**BEFORE THE ADMINISTRATOR**

**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**

In the Matter of the Proposed Operating Permit for:

Kentucky Syngas, LLC, to operate the proposed source located northeast of Central City in Muhlenberg County, Kentucky

Permit No. V-09-001
Source I.D. No. 21-177-00089

Proposed by the Commonwealth of Kentucky, Energy and Environment Cabinet

**PETITION REQUESTING THAT THE ADMINISTRATOR OBJECT TO THE ISSUANCE OF THE PROPOSED TITLE V OPERATING PERMIT FOR THE KENTUCKY SYNGAS FACILITY**

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On behalf of:

SIERRA CLUB

VALLEY WATCH, INC.



Date: October 27, 2010

Pursuant to Clean Air Act § 505(b)(2) and 40 C.F.R. § 70.8(d), Valley Watch and Sierra Club ("Petitioners") hereby petition the Administrator of the United States Environmental Protection Agency ("EPA") to object to the proposed Title V Operating Permit, Permit No. V-09-001, for the source located northeast of Central City in Muhlenberg County ("Permit"), issued by the Kentucky Division for Air Quality ("KDAQ" or "agency") to Kentucky Syngas, LLC ("Kentucky Syngas" or "Applicant").[1] Petitioners provided comments to the Agency on the draft permit leading up to the Permit. A true and accurate copy of these comments is attached.[2] This petition is filed within sixty days following the end of EPA's 45-day review period, as required by Clean Air Act § 505(b)(2).[3] 42 U.S.C. § 7661d(b)(2). The Administrator must grant or deny this petition within sixty days after it is filed. *Id.*

If the Administrator determines that this permit does not comply with the requirements of the Clean Air Act ("CAA") or 40 C.F.R. Part 70, she must object to its issuance. *See* 40 C.F.R. § 70.8(c)(1) ("The 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.") Here, the Permit fails to comply with the applicable CAA requirements and the requirements of 40 C.F.R. Part 70 in multiple respects. First, the Permit was issued pursuant to a faulty public comment period during which, among other things, various plans and other materials relied on by KDAQ in issuing the Permit were absent from the record. Moreover, a final permit was issued even though the public was not afforded the opportunity to review and comment on the revised-proposed permit and materials on which KDAQ relied in issuing that revised-proposed permit, including new $PM_{2.5}$ modeling. Second, KDAQ issued the Permit without considering Petitioners' alternatives, as required by Section 165(a)(2). 42 U.S.C. § 7475(a)(2). Third, KDAQ issued the Permit without adequately assessing whether the Kentucky Syngas facility and the nearby Thoroughbred Mine must be permitted as a single source. Fourth, KDAQ set BACT limit for the facility without satisfying the CAA's clean fuels/clean processes

[1] Exhibit 1, KDAQ, Proposed Air Quality Permit, Permit No. V-09-001, April 9, 2010. Unless otherwise noted, references and citations to the "Permit" are to the Proposed Permit issued on April 9, 2010.

[2] Exhibit 2, Petitioners' Comments on the Draft Air Quality Permit for the Central City Substitute Natural Gas Production Facility, Permit No. V-09-001 (Jan. 19, 2010) (hereafter "Comments").

[3] *See* Exhibit 3, EPA Region 4: Kentucky Proposed Title V Permits, *available at* http://www.epa.gov/region4/air/permits/Kentucky.htm (last visited Oct. 27, 2010) (listing petition deadline of October 27, 2010).

requirements. 42 U.S.C. § 7479(3). Fifth, the Permit is based on a significant underestimation of flaring emissions and fails to contain proper BACT limits for the flare. Sixth, the Applicant and KDAQ underestimated hazardous air pollutant ("HAP") emissions from the facility and failed to ensure that the facility would remain a minor source for HAPs. Seventh, Kentucky Syngas and KDAQ underestimated VOC emissions from the facility. Eighth, the Permit's monitoring provisions are unenforceable as a practical matter, and thus fail to ensure compliance with the Permit's emission limits. Ninth, Kentucky Syngas and KDAQ underestimated particulate matter emissions, thus failing to ensure protection of the $PM_{10}$ and $PM_{2.5}$ NAAQS and PSD increments. Tenth, the Applicant and KDAQ failed to ensure protection of the ozone NAAQS by conducting an inappropriate qualitative assessment of ozone impacts. Finally, in its BACT analyses, the Applicant and KDAQ improperly used $PM_{10}$ as a surrogate for $PM_{2.5}$. For all of these reasons, the Permit is not in compliance with the applicable requirements and the Administrator must object.

## I. BACKGROUND

KDAQ manages a combined program for the state's Title V operating and Prevention of Significant Deterioration ("PSD") construction permits. On December 15, 2008, Kentucky Syngas applied for a PSD/Title V permit for a new substitute natural gas production facility in Muhlenberg County (hereafter "facility" or "proposed facility").[4] On October 27, 2009, Kentucky Syngas submitted a revised permit application (hereafter "Application").[5] KDAQ then issued a draft permit for public comment on December 15, 2009. Petitioners submitted timely comments to KDAQ at a public hearing on January 19, 2010. On April 9, 2010, KDAQ issued a proposed permit without making changes responsive to Petitioners' comments.

The proposed facility will result in hundreds of tons of criteria pollutants each year, in addition to potentially millions of tons of greenhouse gases, which remain uncontrolled under the Permit. As set forth below, the Applicant and KDAQ failed to meet numerous requirements of the Clean Air Act and State Implementation Plan.

[4] Exhibit 4, KDAQ, Proposed Permit Statement of Basis, Permit V-09-001, April 9, 2010 ("SOB").

[5] Exhibit 5, Air Permit Application for New SNG Production Facility, Kentucky NewGas, Central City, Kentucky (Oct. 2009) ("Application"). Unless otherwise noted, all references to Application appendices are referring to appendices to Volume I of the permit application.

## II. STANDARD OF REVIEW

In reviewing a Title V petition, the Administrator must object where petitioners "demonstrate" that the permit "is not in compliance with the requirements of [the Clean Air Act], including the requirements of the applicable implementation plan." *See* 42 U.S.C. § 7661d(b)(2). The Administrator explained in her August 2009 Order for the Trimble Generating Station that EPA will "generally look to see whether the Petitioner has shown that the state did not comply with its SIP-approved regulations governing PSD permitting or whether the state's exercise of discretion under such regulations was unreasonable or arbitrary." Exhibit 6, *In the Matter of Louisville Gas and Electric Company, Trimble County, Kentucky, Title V/PSD Air Quality Permit # V-02-043 Revisions 2 and 3*, Order at 5 (EPA Adm'r Aug. 12, 2009) ("Trimble Order") (citations omitted). This inquiry includes whether the permitting authority "(1) follow[ed] the required procedures in the SIP; (2) [made] PSD determinations on reasonable grounds properly supported on the record; and (3) describe[d] the determinations in enforceable terms." *Id.* (citing 68 Fed. Reg. 9892 (Mar. 3, 2003) and 63 Fed. Reg. 13795 (Mar. 23, 1998)).

To guide her review, the Administrator has looked to the standard of review applied by the Environmental Appeals Board ("EAB") in making parallel determinations under the federal PSD permit program. *Id.* at n.6. The EAB recently reiterated the importance of BACT determinations, stating that they are "one of the most critical elements in the PSD permitting process and thus 'should be well documented in the record, and any decision to eliminate a control option should be adequately explained and justified.'" *In re Desert Rock Energy Company, LLC*, PSD Appeal Nos. 08-03, 08-04, 08-05, & 08-06, slip op. at 50 (EAB Sept. 24, 2009). The Board has remanded permits where the permitting authority's BACT analyses were "incomplete or the rationale was unclear." *Id.* Thus, the Administrator must review KDAQ's BACT determinations with an eye to the completeness of the record and underlying rationale. If either of these aspects is inadequate, the Administrator must object. Given the similar importance of the air quality demonstration and the fact that the determination as to whether there will be a NAAQS violation rides on that demonstration, the Administrator must apply the same level of inquiry is into air quality modeling issues as well.

## III. KDAQ FAILED TO PROVIDE AN OPPORTUNITY FOR MEANINGFUL PUBLIC PARTICIPATION.

### A. The Public Notice Lacked Required Information.

The Administrator must object to the Permit because the public notice failed to include the "end date" of the public comment period. Under Kentucky's Title V regulations, "[t]he *public notice shall include*… [t]he *end date* of the public comment period." 401 KAR 52:100 Section 5(6) (emphasis added). A failure to comply with mandatory notice requirements is grounds for an objection. *See Sierra Club v. Johnson*, 436 F.3d 1269 (11th Cir. 2006); *see also* Trimble Order at 5 (noting that the Administrator reviews whether the permitting agency has complied with the procedural requirements of the SIP).[6] The dictionary meaning of the word "date" is "a particular month, day, and year at which some event happened or will happen,"[7] "time stated in terms of the day, month, and year,"[8] or "a specified day of a month."[9] Thus, KDAQ is required to specify in the notice itself the day, month, and year on which the public comment period will end.

But rather than include the required "end date" in the notice, KDAQ stated merely that written comments "must be postmarked within 30 days following the date of publication [*sic*] this notice."[10] The omission of the *date* from the notice violates the plain language of the regulations.

In addition, even if the public could ascertain the date of the notice independently from the notice itself, the omission of the *end* date creates confusion about when the comment period actually closes. In Kentucky, this confusion is compounded by a lack of clarity about how the agency counts the 30-day period. Prior to January 2010 (and thus during the comment period for the Permit), KDAQ interpreted its regulations to *include* the date of notice in the required 30-day

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[6] *See also* Exhibit 6, August 2009 Trimble Order at 5

[7] Random House Dictionary, Random House, Inc., 2010.

[8] American Heritage Dictionary of the English Language, Fourth Ed., Houghton Mifflin, 2009.

[9] *Id.*

[10] *See, e.g.*, Exhibit 7, KDAQ, Air Quality Permit Notice, Permit # V-09-001.

period.[11] KDAQ subsequently modified its position after consulting with its attorneys and clarified that the 30-day period begins the day *after* publication.[12] Furthermore, KDAQ's notice also caused confusion as to the duration of the comment period because the hearing took place after the end of the 30-day period. This required more clarification by KDAQ regarding whether the comment period would extend all the way through the hearing and whether both written and oral comments would be accepted at the hearing. Nonetheless, instead of simply extending the comment period through the hearing, KDAQ chose to end the written comment period at thirty days and after that time accept only comments (both written and oral) at the hearing. It is unclear why KDAQ would choose such to handle the comment period this way, though it does have the effect of curtailing public participation. In short, the purpose of the explicit regulatory requirement to include the end date of the period is to avoid such confusion. Confusion as to the end date consumes the public's critical comment time in a manner that detracts from the already limited opportunity to comment. This lost time is especially problematic in a state such as Kentucky, which has repeatedly refused to extend the public comment period when requested.

For these reasons, the Administrator must object and direct KDAQ to re-notice the permit with the end date for the 30-day comment period included in the notice itself. At a minimum, the Administrator should require KDAQ to comply with the notice requirements in all future permit proceedings, as the Kentucky SIP expressly requires.

### B. The Plans and Other Information Referenced in the Permit Must be Subjected to Public Notice and Comment.

The Administrator must object because KDAQ omitted necessary information from the permit file available for public review during the comment period. Such materials included various "plans," as well as other information relied on by KDAQ in issuing the Permit. These omissions deprived the public of a meaningful opportunity for comment.

Under state and federal regulations, a Title V application must include detailed emissions information for all sources of emissions (including emission calculations), control technology

[11] *See* Exhibit 8, e-mail from James Morse, KDAQ, to Faith Bugel, ELPC, "Public Comment Period for KY Syngas," January 6, 2010. It is Petitioners' understanding that this interpretation was not in keeping with that of either EPA or other states.

[12] *See id.*

and compliance information, and "information that may be necessary to implement and enforce other applicable requirements of the Act or of [Title V] or to determine the applicability of such requirements." 40 C.F.R. § 70.5(c). By failing to make necessary information "available for review during the title V public comment process," KDAQ violated the Clean Air Act's implementing regulations. *In the Matter of WE Energies Oak Creek Power Plant*, Permit No. 241007690-P10, Order Responding to Petitioner's Request that the Administrator Object to Issuance of State Operating Permit, at 23-27 (June 12, 2009) (all information needed to determine the applicability of requirements and impose required limits must be included in the application and "must be available for review during the title V public comment process," citing 40 C.F.R. § 70.7(h)(2)); *see also In re RockGen Energy Center*, 8 E.A.D. 536, 552-55 (EAB 1999) (remanding permit due to failure to include startup, shutdown and malfunction plan in the permit and subject it to public comment).

Throughout the Permit, KDAQ references, and relies on, various "plans" and other information in concluding that this facility will comply with applicable requirements. But KDAQ did not include this information in the draft permit or elsewhere in the permit record for public comment. Nor was this information included in the Application or, it appears, reviewed by KDAQ prior to proposing the permit to EPA. This is precisely the error that caused EPA to object to the Wisconsin Electric Oak Creek permit last year. *See WE Energies.* The categories of required information that were shielded from public scrutiny during the Kentucky Syngas public comment period are numerous and serious. They include, but are not limited to, the following:

a. the flare monitoring plan referenced on page 11 of the Permit;
b. the startup, shutdown, and malfunction plan ("SSM plan") referenced on page 13 of the Permit;
c. the written operation plan for the sulfur recovery unit ("SRU") and pollution control devices, referenced on page 23 of the Permit;
d. a more-detailed leak detection and repair ("LDAR") plan, if any, relied on to control fugitive emissions;
e. the supporting materials for the estimated controlled emissions under the LDAR plan;
f. any instructions or standards for distinguishing between "normal" and "abnormal" visible emissions from the ABS tower vent (EU-02), *see* Permit at 22;
g. the AGR vent sampling plan referenced on page 31 of the Permit; and

h. the fugitive coal dust emissions control plans referenced on pages 82 and 86-89 of the Permit.

For each of the above-mentioned plans, programs, instructions, or standards, that information must be developed prior to the draft permit, reviewed by KDAQ, subjected to public review and comment, and made part of the permit record. *See RockGen Energy Center*, 8 E.A.D. at 552-55 (holding that provisions requiring a post-permit plan to be submitted were invalid and requiring the permitting agency to subject any provisions relied upon for permitting to public notice and comment).

In their comments on the draft permit, Petitioners pointed out that much of the information listed above was missing from the permitting record, and that this information must be submitted to KDAQ and made available to the public before issuance of a proposed Title V permit. *See, e.g.*, Comments at 38 & n.81, 41-43, 46, 65. But despite Petitioners' comments, KDAQ refused to make all the necessary information publicly available and to establish a new comment period.[13] By disregarding the express requirements of 40 C.F.R. §§ 70.5 and 70.7(h), KDAQ has violated the Clean Air Act's implementing regulations. Moreover, KDAQ fails to acknowledge that its violation of these requirements deprives the public of the opportunity to comment on the sufficiency of the proposed Permit's new analyses and additional permit terms and conditions, which themselves may (and as set forth below, in fact do) continue to fall short of CAA requirements. For these reasons, the Administrator must object and direct KDAQ to make *all* necessary information available to the public and to hold an additional public comment period prior to any issuance of a revised proposed Title V permit.

### C. KDAQ Failed to Provide Public Notice of Its Revised Permit.

The Administrator must object because KDAQ failed to provide notice of a revised-proposed permit it submitted to EPA on July 14, 2010 (the "Revised-Proposed Permit")[14] until a Final Permit for Kentucky Syngas (the "Final Permit," attached hereto as Exhibit 9b) was made available to the public on September 28, 2010, and failed to make available for public review and

[13] *See, e.g.*, Exhibit 9, Comments and Response On The Draft Permit ("Response to Comments" or "RTC"), at J-105 (refusing to make the AGR vent sampling plan publicly available prior to issuance of the final Permit).

[14] *See* Exhibit 9a, Executive Summary for the final Kentucky Syngas Title V/Title I – PSD, Construction/Operating permit, dated September 24, 2010, at 6.

comment the Revised-Proposed Permit and all supporting materials related to it, including a $PM_{2.5}$ modeling analysis conducted by Kentucky Syngas that purports to demonstrate compliance with the NAAQS. These materials were added to the record after the close of public comment. KDAQ's failure to submit these materials for public review and comment violates the Clean Air Act's public participation requirements.

After EPA sent a Title V objection letter to KDAQ on May 24, 2010, KDAQ submitted the Revised-Proposed Permit, along with a new $PM_{2.5}$ modeling analysis and other unknown documents, to EPA on July 14, 2010. KDAQ provided no notice in the newspaper of the Revised-Proposed Permit, nor was any notice sent to KDAQ's mailing list. While the Revised-Proposed Permit was posted on the web in July 2010,[15] such posting does not suffice to provide legal notice. Petitioners did not learn of the Revised-Proposed permit until after September 28, 2010, when KDAQ posted the Final Permit, along with the Revised-Proposed Statement of Basis, the Executive Summary, and the permit Summary on KDAQ's website.[16] And Petitioners only knew to search KDAQ's website for Final Permit due to their unique position as petitioners in an ongoing appeal of the previous version of the permit; the general public, in contrast, did not have that benefit. Thus, the public was never legally notified of the existence of the Revised-Proposed Permit, much less of the opportunity to review and comment on that permit and materials supporting its issuance. As detailed below, KDAQ's failure to provide such notice and comment was contrary to law.

Section 165(a) of the Act, 42 U.S.C. § 7475(a)(2), requires that "a public hearing [be] held with an opportunity for interested persons . . . to appear and submit written or oral presentations *on the air quality impact. . . .*" (Emphasis added.) Additionally, § 7475(a)(3) requires that the facility demonstrate that it will not cause a violation of the NAAQS and § 7475(e)(3)(B) and (C) require the analysis of air quality impacts to be done and the results to "be available *at the time of the public hearing* on the application. . . ." (Emphasis added.) These requirements were not fulfilled for $PM_{2.5}$ since Kentucky Syngas's analysis was not done, and therefore the results were not available, until after the public comment period. Moreover, the

[15] *See* Ex. 9c, email from James Morse to Faith Bugel and Lisa C. Jones, dated Oct. 26, 2010.

[16] *See* Exhibit 9d, KY Department of Environmental Protection Online Search - Kentucky Syngas LLC, *available at* http://dep.gateway.ky.gov/esearch/search_ai_detail.aspx?AgencyID=35762 (last visited Oct. 25, 2010).

model used for $PM_{2.5}$ was not "specif[ied] with reasonable particularity," pursuant to 42 U.S.C. § 7475(e)(3)(D), until well after the comment period closed.[17]

Kentucky regulations also require public review and comment for the Revised-Proposed Permit and all supporting materials. 401 KAR 52:020 Section 25 provides that "[a]ll permits, permit renewals, and permit revisions issued under this administrative regulation, other than administrative permit amendments, shall be offered for review by the public, affected states, and the U.S. EPA pursuant to 401 KAR 52:100 [Kentucky's public review and comment regulations for permit actions]." Administrative permit amendments are limited to the following:

> (a) [c]orrect typographical errors; (b) [c]hange the name, address, or phone number of a person identified in the permit, or make similar minor administrative changes; (c) [c]hange in ownership or operational control if the cabinet determines that no other changes in the permit are necessary; (d) [r]equire more frequent monitoring or reporting; and (e) [i]ncorporate into a Title V permit the requirements from preconstruction review permits . . . .

401 KAR 52:020 Section 13(1). Far from making ministerial changes like those listed above, the Revised-Proposed Permit adds new operating requirements, not included in the April 9 Permit, for the Firewater pump (EU06), the Standby Generators (EU07), and the Gasifier Vent (EU13).[18] These new requirements are not administrative permit amendments. As such, under Kentucky's own regulations, public review and comment apply.

KDAQ's failure to provide a new public comment opportunity on the new $PM_{2.5}$ analysis undermines Congress' purpose in 42 U.S.C. § 7470(5) to assure decisions are only made "after careful evaluation... and after adequate procedural opportunities for informed public participation in the decisionmaking process." The Administrator should object on this basis. *See In re. Haw. Elec. Light Co., Inc.*, 8 E.A.D. 66, 102 (EAB 1998) (holding that "Congress determined that the air quality analysis required by the regulations 'shall by available at the time of the public hearing on the application for such permit.' CAA § 165(e)(3)(C), 42 U.S.C. § 7475(e)(3)(C)" and remanding where public was not given an opportunity to comment on the air quality analysis data); *In re Indeck-Elwood, LLC.*, 13 E.A.D.__, PSD Appeal No. 03-04, Slip. Op. at n.70 (EAB Sept. 27, 2006) (finding that an analysis of soil and vegetation impacts by U.S.

[17] *See* Letter from Kenneth R. Lapierre, EPA, to John S. Lyons, KDAQ (May 24, 2010) (attaching March 23, 2010 memorandum detailing $PM_{2.5}$ modeling protocol).

[18] *See* Final Permit, Exhibit 9b, at 34, 48.

EPA could not save Illinois EPA's failure to do such analysis on the record because U.S. EPA's analysis "[has] not yet been subjected to public scrutiny under the PSD permitting process.")

Federal case law confirms that objection is appropriate. Where an agency fundamentally changes the information or methodology behind its decision, or conducts a new analysis, after the public comment period closes, it must reopen the comment period. *See Ober v. EPA*, 84 F.3d 304, 313-14 (9th Cir. 1996); *Idaho Farm Bureau Federation v. Babbitt*, 58 F.3d 1392, 1402-03 (9th Cir. 1995) (finding a violation of public procedures where Fish and Wildlife Service relied on a new report not previously part of the administrative record). A permitting agency may only supplement data that was unavailable during the notice and comment period where it expands on and confirms information contained in the proposed decision and also addresses alleged deficiencies, provided no prejudice is shown. *Idaho Farm Bureau*, 58 F.3d at 1402 (quoting *Solite Corp. v. EPA*, 952 F.2d 473, 484 (D.C. Cir. 1991)). Where, however, the agency relies on data that is central to its decision and was not available in the record for the proposed decision, a new public opportunity to comment is required. *Id.* at 1403 ("the necessity for notice and opportunity to comment on the USGS study was greatly heightened because FWS relied largely on the USGS study to support its final rule"); *Ober*, 84 F.3d at 314 (finding a new public comment period is required on information added to the record after the close of comment where the information "addressed the submitted Implementation Plan's failure to comply with an essential provision of the Clean Air Act" and the "added material related to the Implementation Plan's compliance with a critical statutory provision"). The $PM_{2.5}$ analysis conducted by Kentucky Syngas was entirely new: it did not expand on or supplement information already in the record because the only prior modeling done was modeling for $PM_{10}$ – a modeling analysis EPA *specifically rejected* as failing to demonstrate compliance with the $PM_{2.5}$ NAAQS.[19]

For these reasons, the Administrator must object and direct KDAQ to make the Revised-Proposed Permit and all supporting documentation, including Kentucky Syngas' $PM_{2.5}$ modeling analysis, available to the public for review and comment prior to the issuance of any new revised proposed Title V permit.

[19] *See* Letter from Kenneth R. Lapierre, EPA, to John S. Lyons, KDAQ (May 24, 2010), *supra* note 15.

## IV. KDAQ FAILED TO CONSIDER AND RESPOND TO COMMENTS ON ALTERNATIVES.

The Administrator must object because KDAQ failed to consider, and respond to all comments about cleaner alternatives to the proposed Kentucky Syngas facility. *See* 42 U.S.C. § 7475(a)(2), 40 C.F.R. § 51.166(q)(vi).

Section 165(a)(2) of the Clean Air Act requires as part of the permitting for a proposed major source that the public be provided the opportunity to submit testimony on the "air quality impacts of such source, *alternatives thereto*, control technology requirements, and other appropriate considerations." 42 U.S.C. § 7475(a)(2) (emphasis added); *see also In re Prairie State Generating Co.*, PSD Appeal No. 05-05, Slip Op. at 40 (EAB 2006). In addition, a permitting agency has the duty to respond to all substantive comments raised during the public comment period, including those raising alternatives. *See In the Matter of Cash Creek Generation*, LLC, Petition Nos. IV-2008-1 & IV-2008-2, Order Responding to Petitioner's Request that the Administrator Object to Issuance of State Operating Permit, at 17-19 (EPA Adm'r Dec. 15, 2009). Because KDAQ is required to respond to comments submitted by the public, the agency must substantively address the alternatives issues raised in Petitioners' and other public comments. Here, KDAQ violated the CAA in failing to evaluate alternatives to the proposed facility, including a no-build alternative and other alternatives including, but not limited to, energy efficiency and renewable energy.

In their comments on the draft permit, Petitioners specifically identified several alternatives to the proposed facility, including a no-build alternative, energy efficiency alternatives, and renewable energy alternatives. *See* Comments at 2-4 (hereafter "Comments"). Thus, under Section 165(a)(2), KDAQ was required to consider these alternatives.

Instead, in its Response to Comments KDAQ flatly refused to consider the alternatives, asserting that the law does not require "an applicant for an air permit to demonstrate that there is a need for the proposed facility." RTC at J-10. Additionally, KDAQ argued that no further response was needed because these issues are "beyond the purview of the Kentucky Division for Air Quality for this permitting action." *Id.* By claiming that it did not have authority to consider these alternatives, KDAQ has staked out a position contrary to the Environmental Appeals Board's ("EAB") decision in *Prairie State*, which concluded that "permit issuers have authority to consider 'alternatives' to the proposed facility," such as renewable energy facilities. Slip op.

at 38; *see also id.* at 42 ("[W]e decline to adopt the view that consideration of need for a facility is outside the scope of section 165(a)(2) of the Clean Air Act."). KDAQ's failure to consider these alternatives is unlawful, and the Administrator must object to issuance of the Permit.

## V. KDAQ'S DECISION TO PERMIT THE KENTUCKY SYNGAS FACILITY AND THOROUGHBRED MINE SEPARATELY IS ARBITRARY AND CAPRICIOUS.

The Administrator must object because KDAQ failed to adequately inquire whether the Kentucky Syngas facility must be permitted with the adjacent Thoroughbred Mine as a single source.

Under the Clean Air Act, if a cluster of related facilities meet certain criteria, they must be permitted as a single source. *See Alabama Power Co. v. EPA*, 636 F.2d 323, 397 (D.C. Cir. 1979) (noting that Congress "clearly envisioned that entire plants could be considered to be single 'sources'"). Under EPA regulations, related facilities are aggregated as a single source if they are contiguous or adjacent, under common control, and classified in the same 2-digit SIC group. *See* 40 C.F.R. §§ 51.166(b)(5), (b)(6). Kentucky's federally-approved state implementation plan ("SIP") is consistent with EPA regulations. *See* 401 KAR 51:017 Section 1(9); 401 KAR 51:017 Section 1(38) (Mar. 12, 1997). In addition, if two facilities meet the first two criteria, but are not classified under the same two-digit SIC code, they must be still be permitted together if one facility is a "support facility" for the other. *See, e.g.*, 45 Fed. Reg. 52676, 52695 (Aug. 7, 1980).

Here, KDAQ erred by failing to properly analyze the mine's status as a support facility. The Kentucky Syngas facility and Thoroughbred Mine meet the first two criteria, and the available evidence indicates that Thoroughbred would be a support facility to the Syngas facility. First, the Thoroughbred Mine and Kentucky Syngas facility meet the common control requirement. *See, e.g.*, Exhibit 10, Project Fact Sheet, *available at* http://www.kentuckynewgas.com/wp-content/uploads/2008/12/ProjectFactSheet1.pdf. Second, Kentucky Syngas and the Thoroughbred Mine also meet the adjacency requirement. As Petitioners explained in their comments on the draft permit, when two facilities are functionally related, interdependent (i.e., connected by pipelines), or otherwise connected by unique structures, they are considered adjacent for CAA purposes.[20] Indeed, Kentucky Syngas has already conceded that the proposed facility is adjacent to the mine: "Peabody has large coal reserves adjacent to the site." Exhibit 10, Project Fact Sheet. In addition, coal from the mine would be delivered by conveyor, constituting a unique structure tying the two sources together. *See* SOB at 2, 90. Consequently, the Thoroughbred Mine and the Kentucky Syngas facility meet the adjacency requirement, and KDAQ erred in concluding otherwise. *Cf.* RTC at J-15 (concluding that the facility and mine are not adjacent).

As to the third criterion, facilities do not have to have the same SIC code to be considered interrelated. EPA has a longstanding policy that facilities are to be aggregated, even if they have different SIC codes, if they are "support facilities" that are integrally related with the primary activity at the site. As EPA explained, "one source classification encompasses both primary and support facilities, even when the latter includes units with a different two-digit SIC code. Support facilities are typically those which convey, store, or otherwise assist in the production of the principal product." 45 Fed. Reg. at 52695. EPA has identified other relevant factors that could establish one facility as supporting another. *See* Letter from EPA Region 5 to Wisconsin Dept. of Natural Resources Re: Oscar Mayer Foods (Aug. 25, 1999). But, the fact remains that the extent to which the support facility provides output for the primary facility bears directly on whether those facilities must be jointly permitted. In other words, if the majority of the Thoroughbred Mine's output goes to the Kentucky Syngas facility, the mine likely constitutes a support facility.

Here, however, KDAQ failed to adequately assess whether Thoroughbred is a support facility for the Kentucky Syngas facility.[21] The permitting record lacks the information

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[20] *See, e.g.*, Letter from EPA Region 8 to Utah Division of Air Quality Re: Utility Trailer Manufacturing Co. (May 21, 1998) (finding that mine and a processing plant constituted a single source even though they were 35-40 miles apart, because they were connected by a 44-mile-long dedicated pipeline that made them "functionally interdependent"); Letter from EPA Region 8 to Utah Dept. of Environmental Quality Re: Great Salt Lake Minerals (Aug. 8, 1997) (finding that a salt processing plant and a pump station 21.5 miles apart were a single source, because the dedicated pipeline between them demonstrated that they were functionally interrelated); *see generally* Comments at 5-6 (citing additional examples).

[21] Rather than independently investigate whether the facility and Thoroughbred should be permitted as a single source, KDAQ simply asked the Applicant whether the two projects should be permitted jointly. Kentucky Syngas responded, "Although it is anticipated that the Thoroughbred Mine will be the main coal source for the Kentucky NewGas facility because it will be the most economical, coal from the Thoroughbred Mine is neither required nor anticipated to be the sole coal source for the facility." Exhibit 11, e-mail from Ralph Gosney to Heather Abrams (Apr. 8, 2009) ("Gosney e-mail"). "The Thoroughbred

necessary to make that determination. Because Kentucky Syngas provided too little detail as to the percentage of Thoroughbred coal that will be processed at the Kentucky Syngas facility, KDAQ had inadequate information upon which to base its decision. KDAQ must thoroughly investigate the extent to which the Thoroughbred Mine's output will be processed by Kentucky Syngas, and whether there are other factors establishing the Thoroughbred Mine as a support facility. Because KDAQ's decision to permit the two facilities separately was contrary to law, the Administrator must object to issuance of the Permit.

## VI. THE BACT ANALYSES OMITTED CONSIDERATION OF CLEAN FUELS AND PROCESSES.

The Administrator must object because KDAQ and the Applicant failed to adequately consider use of clean fuels and cleaner production processes in setting BACT limits for the facility. Under the Clean Air Act, a BACT determination must include consideration of "clean fuels." 42 U.S.C. § 7479(3); *see also Sierra Club v. EPA*, 499 F.3d 653, 655 (7th Cir. 2007) ("The Act is explicit that 'clean fuels' is one of the control methods that EPA has to consider."). Indeed, "[c]ongressional direction to permitting applicants and public officials is emphatic. In making determinations, they are to give prominent consideration to fuels." *In re Northern Michigan University Ripley Heating Plant*, PSD Appeal No. 08-02, slip op. at 17-18 (EAB 2009). The Kentucky SIP likewise defines BACT as requiring consideration of less-polluting fuels. *See* 401 KAR 51:001, Section 1(8) (SIP-approved version). As the EAB has explained:

> The phrase 'clean fuels' was added to the definition of BACT in the 1990 Clean Air Act amendments. EPA described the amendment to add 'clean fuels' to the definition of BACT at the time the Act passed, 'as * * * codifying its present practice, which holds that *clean fuels are an available means of reducing emissions to be considered along with other approaches to identifying BACT level controls*.' EPA policy with regard to BACT has for a long time required that the permit writer examine the inherent cleanliness of the fuel.

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Mine will not operate solely to supply coal to the Kentucky NewGas facility and may sell coal to other users." *Id.* Based on these statements, KDAQ apparently concluded that the facilities need not be permitted as a single source. KDAQ, however, held the facility to the wrong threshold. The standard is not whether the mine is the sole coal source for the facility, nor whether the facility is the sole recipient of coal from the mine. As explained above, the test is whether the *majority* of the coal from the mine is sent to the Kentucky Syngas facility.

*Inter-Power of New York*, 5 E.A.D. 130, 134 (EAB 1994) (emphasis added, internal citations omitted); *see also In re Knauf Fiberglass, GmbH*, 8 E.A.D. 121, 136 (EAB 1999); *Old Dominion Electric Cooperative*, 3 E.A.D. 779, 794 n. 39 (EPA Adm'r 1992) ("BACT analysis should include consideration of cleaner forms of the fuel proposed by the source."); *Hibbing Taconite*, 2 E.A.D. 838, 842-843 (EPA Adm'r 1989) (remanding a permit because the permitting agency failed to consider burning natural gas as a viable pollution control strategy); *In re East Kentucky Power Coop. Inc.*, Order Objecting to State Issued Permit V-06-007, at 30 (EPA Adm'r Aug. 30, 2007) (objecting to Title V permit for failure to demonstrate that cleaner fuel, low-sulfur coal, was not achievable and should not be used to establish BACT). Cleaner fuels must therefore be considered in a BACT analysis.[22]

The CAA also requires that BACT limits be established "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 each such pollutant." 42 U.S.C. § 7479(3) (emphasis added). In other words, BACT requires that cleaner processes be employed in order to achieve the maximum achievable degree of reduction in PSD pollutants.

For a gasification plant like the Kentucky Syngas facility, the clean fuels/clean processes standard may require, among other things, the use of natural gas or landfill gas in some processes (especially to replace syngas or SNG for production and combustion processes), gasification of less-polluting feedstocks such as biomass or lower-sulfur coal, and limits on gasification of heavily-polluting feedstocks such as petroleum coke. Because KDAQ failed to properly consider clean fuels and production processes in the BACT analysis, the Permit is legally deficient.

[22] An applicant may escape the requirement to use the fuel or fuel blend associated with the lowest levels of emissions only if using that fuel would not be achievable due to economic, energy, or other environmental concerns. *See Alaska Dep't of Envt'l Cons. v. EPA*, 540 U.S. 461, 476 (2004) (citing Draft NSR Manual at B.6 (1990)); *In re E. Ky Power Coop.* A permitting agency may only sparingly make a finding that clean fuel is not feasible, and only based on circumstances unique to the project. *See In re Kawaihae Cogeneration Project*, 7 E.A.D. 107, 116-17 (EAB 1997); *see also In re World Color Press, Inc.*, 3 E.A.D. 474, 478 (Adm'r 1990).

### A. KDAQ and the Applicant Failed to Adequately Consider Clean Fuel Alternatives For The Facility's Feedstocks.

In its RTC, KDAQ suggests that a clean fuels analysis of the facility's feedstock alternatives is unnecessary because coal and petroleum coke are being used to make other products, rather than being burned as fuel. RTC at J-23 to -24. Kentucky Syngas and KDAQ, nonetheless, have already conceded that feedstock alternatives are properly subject to a clean fuels analysis. *See* Application at 5-6; SOB at 90. Moreover, even if the facility's feedstocks were not characterized as fuels, KDAQ would still be required to analyze the potential emissions of different feedstock alternatives under BACT. The BACT inquiry broadly encompasses "production processes or available methods, systems, and techniques" for reducing pollution, 40 C.F.R. § 51.166(b)(12), clearly extending to both clean fuels and feedstocks (to the extent that feedstocks can even be distinguished from clean fuels). KDAQ must thoroughly evaluate the use of biomass and lower-sulfur coal, and a prohibition on petroleum coke, in a clean fuels/clean processes BACT analysis.

#### 1. Biomass

KDAQ erred in failing to conduct a proper top-down BACT analysis that considers the use of biomass as a feedstock alternative and in failing to require Kentucky Syngas to submit an evaluation of biomass as part of the BACT analyses for the facility. Neither the Application nor KDAQ's SOB discusses the use of biomass as a feedstock alternative. If low-impact biomass were used to satisfy some or all of the facility's feedstock requirements, the facility would produce fewer emissions of greenhouse gases, hazardous air pollutants, sulfur dioxide, sulfuric acid mist, and other pollutants. A proper top-down BACT analysis must consider low-impact biomass inputs into the gasification process, whether alone or in combination with coal, as opposed to coal alone. And biomass gasification has already been demonstrated as a feasible technology.

One recent example of biomass gasification was the announcement by Progress Energy Florida that it signed another contract with Biomass Gas & Electric LLC ("BG&E") to purchase electricity from a waste-wood biomass plant planned for Florida.[23] This was the second biomass

[23] *See* Exhibit 12, http://www.ct-si.org/news/press/item.html?id=240; http://www.green-energy-news.com/nwslnks/clips208/feb08014.html.

gasification plant that BG&E signed a contract to build, and the company proposes to build a total of four. The Progress Energy plant, which will be built in north or central Florida, will use waste wood products—such as yard trimmings, tree bark, and wood knots from paper mills—to create electricity. The gasification process would supply sufficient fuel to generate about 75 MW of power. Commercial operation is projected to begin in June 2011.

More recently, Xcel Energy proposed to build a biomass gasification plant at the site of its existing Bay Front Generating Station in Ashland, Wisconsin.[24] According to Xcel Energy:

> Biomass gasification is a technology that has been studied and developed over the past half century and continues to have global activity due to growing interest in clean, renewable energy. Hundreds of biomass gasifiers are in operation around the world. The majority of these are in Asia and Europe and are small-scale plants providing less than 5 MWe of heat or electricity to farms and small industries. To date, biomass gasification installations for production of electricity in the U.S. have predominantly been small-scale plants; however, some larger-scale plants have been installed in recent years. The pulp and paper and food processing industries have employed biomass gasification to a much greater extent in the U.S. to provide steam . . . .[25]

The Xcel gasifier will gasify 200,000 to 250,000 tons of biomass annually.[26] Recent publicly-available cost information shows that using biomass is cost-effective. The Xcel Bay Front facility is currently paying between $25.00 and $29.00 per ton of wood waste, which provides between 5,500 and 6,500 Btu/pound ($3.85 to $5.27/MMBtu).[27]

Kentucky likewise has tremendous biomass potential. As the Governor's Executive Task Force on Task Force on Biomass and Biofuels Development recently noted, Kentucky could

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[24] *See* Exhibit 13, Application of Northern States Power Company, a Wisconsin Corporation, for a Certificate of Authority and Any Other Authorizations Needed to Construct and Place Into Operation a Biomass Gasifier at Its Bay Front Generating Facility, Docket No. 4220-CE-169, PSC Ref # 108437, at 6 (Feb. 23, 2009).

[25] *Id.* at 6.

[26] *Id.* at 8.

[27] *See* Exhibit 14, Assessment of Biomass Resources for Energy Generation at Xcel Energy's Bay Front Generating Station at Ashland, Wisconsin, Energy Center of Wisconsin, 2007.

produce an estimated 12-15 million tons per year of biomass production capability with minimal land use changes, and 25 million tons could be produced sustainably by 2025.[28]

In order to satisfy CAA requirements, KDAQ must require Kentucky Syngas to submit an evaluation of biomass as part of the BACT analyses for the facility, and KDAQ can allow Kentucky Syngas to avoid using biomass only if the company can demonstrate, and KDAQ can independently confirm, that the cost of pollutant removal from using such fuel is "disproportionately high when compared to the cost of control for that particular pollutant and source in recent BACT determinations." Exhibit 16, EPA, Draft NSR Manual (1990) ("NSR Manual") at B.31-.32.

KDAQ failed to analyze biomass as a feedstock alternative before issuing the Kentucky Syngas Permit. Indeed, KDAQ refused to do so, asserting that "biomass is not an available option for Kentucky Syngas." RTC at J-26. This unsupported claim is an insufficient basis for refusing to consider biomass as a potential clean fuel alternative for the facility's feedstocks.

### 2. Lower-Sulfur Coal

Although Kentucky Syngas and KDAQ purported to consider lower-sulfur coals, Application at 5-5 to 5-8, SOB at 90-92, their evaluation of this potential feedstock was deficient in several respects. Low-sulfur coal, whether it be subbituminous coal from the Powder River Basin ("PRB coal") or low-sulfur bituminous coal from the East, was rejected based on cost. Although economic considerations may be properly considered in a BACT analysis, KDAQ's rejection of lower-sulfur coal was inadequate for the reasons explained below.

Lack of Supporting Evidence. As a threshold matter, KDAQ's rejection of low-sulfur was unwarranted because the agency failed to provide a sufficient evidentiary basis for its conclusion. As EPA has repeatedly emphasized, a permitting authority cannot reject a clean fuel alternative simply because the applicant's preferred feedstock source is cheaper. *See In re East Kentucky Power Coop.*, Order at 30 (objecting to Title V permit issued by KDAQ for failure to demonstrate that low-sulfur coal was not achievable); Exhibit 17, EPA Region 4, Air Permits Section, Comments on Draft PSD Permit for Duke Energy Carolinas, LLC, Cliffside Steam

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[28] Exhibit 15, Executive Task Force on Biomass and Biofuels Development in Kentucky, Final Report, at 19-20 (Dec. 10, 2009), *available at* http://www.energy.ky.gov/NR/rdonlyres/EB1A582B-7FC4-440D-A697-D673929A5B55/0/FinalReport.pdf.

Station, Unit 6 Project at 4 (Oct. 3, 2007) (because the proposed unit can burn either subbituminous or bituminous coal, the fuel type is not fundamental to the project and BACT must be established based on the cleaner PRB coal).

In this instance, KDAQ's SOB relies entirely upon Kentucky Syngas's assertion that the use of lower-sulfur alternatives would be prohibitively expensive. By uncritically accepting Kentucky Syngas's cost figures, and by failing to provide any independent data or information to support those numbers, KDAQ has failed to "adequately document its decision making." *Indeck-Elwood LLC*, 13 E.A.D. __ , PSD Appeal No. 03-04, slip op. at 29 (EAB Sept. 27, 2006). Rather than simply cut-and-paste from the permit application, KDAQ must provide an independent evaluation of the costs of different feedstock sources, and explain why it agrees with the Applicant's conclusions.[29]

Failure to Consider Other Lower-Sulfur Options. Although KDAQ considered one low-sulfur alternative from the East – the "lowest-sulfur" eastern coal with a purported cost of \$123.5/ton[30] – the agency failed to consider other lower-sulfur alternatives. Rather than only considering eastern coal with a 0.72% sulfur content, KDAQ should have considered other, less-expensive eastern coals that have a lower sulfur content than the applicant's preferred source. For example, the most recent price for Central Appalachian coal, which has a 1.2% sulfur content (much lower than the 4.4% sulfur content of the applicant's preferred feedstocks), is only

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[29] There is, in fact, much to question about the reliability of Kentucky Syngas's cost figures. The company asserts, without elaboration, that its figures are "based [*sic*] reference data from SNL Energy, a market research firm," but the application provides none of the underlying data. Application at 5-7. And the company claims that the delivered cost of the applicant's preferred feedstocks would be \$35.8/ton, while PRB coal would cost \$52.5/ton and low-sulfur eastern bituminous coal would cost \$123.5/ton. *Id.* The PRB and eastern low-sulfur figures seem high, especially given that recent spot prices for PRB coal were \$8.4/ton. *See* Exhibit 18, Energy Information Administration, *Average Weekly Coal Commodity Spot Prices* (Dec. 22, 2009). Although transportation costs from the PRB would undoubtedly be higher than those for Kentucky-based sources, the Applicant and KDAQ failed to provide an explanation for this discrepancy in price. Kentucky Syngas's figure of \$123.50/ton for low-sulfur eastern coal is likewise difficult to accept without supporting information. Indeed, in a Statement of Basis issued only a year before Kentucky Syngas's initial permit application, KDAQ cited a cost of low-sulfur eastern bituminous coal of \$50-\$72/ton. *See* KDAQ, Permit Statement of Basis, East Kentucky Power Cooperative, Inc., Hugh L. Spurlock Generating Station (Dec. 22, 2007), at 3-4. If, as KDAQ's SOB suggests, the price of low-sulfur eastern coal has risen between 172% and 247% within a single year, KDAQ must provide evidence to support that assumption. Even after Petitioners raised this issue in their Comments, KDAQ and Kentucky Syngas failed to provide evidence to support their cost figures. *See generally* RTC at J-27 to J-28.

[30] Application at 5-6; SOB at 91.

\$54.15/ton[31] – substantially lower than the delivered cost of the "lowest-sulfur" eastern coal. In its Response to Comments, KDAQ went on to suggest without any additional basis that a lower-sulfur coal would be cost prohibitive, RTC at J-28, and failed to explain why. Not only does the evidence not support this claim, but increased costs, standing alone, are insufficient to justify rejecting cleaner fuels as a control option for regulated pollutants. *See Alaska Dep't*, 540 U.S. at 476.

Faulty Cost Analysis. Even assuming the cost figures for different coal sources were accurate, and even assuming KDAQ could ignore both biomass and other lower-sulfur coal sources, the agency's conclusion that the use of low-sulfur feedstocks is not economically viable is still fatally deficient. Permitting agencies must follow a specific methodology when rejecting clean fuels based on cost, and KDAQ failed to follow that methodology here.

Under the CAA, increased costs, standing alone, are insufficient to justify rejecting cleaner fuels as a control option for regulated pollutants. *See Alaska Dep't*, 540 U.S. at 476 (rejecting a BACT analysis where the agency eliminated a control option on claims of economic infeasibility without adequate justification). Rather, to justify rejecting clean fuels as a pollution control option in a BACT analysis, the cost-per-ton of pollutant prevented must be disproportionate to the cost-per-ton incurred by other sources controlling the pollutant in recent BACT determinations. *See In re Masonite Corporation*, 5 E.A.D. 551 (EAB 1994); *see also* NSR Manual at B.44 (noting that a permitting agency must determine that the cost-per-ton reduced is beyond "the cost borne by other sources of the same type in applying that control alternative"); *see also In re Steel Dynamics*, 9 E.A.D. 165, 202 (EAB 2000); *Inter-Power*, 5 E.A.D. at 135 ("In essence, *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.*") (quoting NSR Manual at B.44) (emphasis in original). In sum, to determine whether the use of a control option is cost effective, the permitting agency must compare that option's cost-effectiveness with what other companies in the same industry have been required to pay for that option. Because KDAQ's clean fuels BACT analysis lacks any comparison with other similar emission sources,

[31] *See* Exhibit 18, Energy Information Administration, *Average Weekly Coal Commodity Spot Prices* (Dec. 22, 2009). And again, PRC coal is quoted at only \$8.4/ton.

*see* SOB at 90-92, including a threshold for costs that are excessive relative to other plants, the BACT analysis remains incomplete and inadequate.

KDAQ's conclusion – that lower-sulfur coal is not an economically viable alternative – is also deficient because the agency relied solely on incremental costs rather than average costs. Cost considerations in determining BACT are expressed in one of two ways: average cost effectiveness or incremental cost effectiveness. Incremental cost effectiveness is an optional consideration that must always be paired with average cost effectiveness. *See* NSR Manual at B.41 ("[I]ncremental cost effectiveness should be examined in combination with the total cost effectiveness in order to justify elimination of a control option."), B.43 ("As a precaution, differences in incremental cost among dominant alternatives cannot be used by itself to argue one dominant alternative is preferred to another."). The NSR Manual warns that "undue focus on incremental cost effectiveness can give an impression that the cost of a control alternative is unreasonably high, when, in fact, the total cost effectiveness, in terms of dollars per total ton removed, is well within the normal range of acceptable BACT costs." *Id.* at B.45-.46. Here, both KDAQ and Kentucky Syngas ignored the average cost of lower-sulfur coal in reaching their conclusion that such coal is not economically viable. Instead, they relied *entirely* upon lower-sulfur coal's purported incremental cost in reaching this conclusion. This "undue focus on incremental cost[s]" was improper. *Id.*

<u>Failure to Consider Other Pollutants</u>. KDAQ's clean fuels analysis for the facility's feedstock is also faulty because the agency failed to consider pollutants other than $SO_2$. As Kentucky Syngas acknowledged in its application, using "subbituminous coal [such as PRB coal] . . . may have an effect on emissions of other PSD triggering pollutants." Application at 5-6. Despite this acknowledgment, the company's clean fuels analysis only considered the potential reductions in $SO_2$, since the company deemed that pollutant to be the "most significant." *Id.* Again, KDAQ uncritically accepted the company's claims, making no attempt to consider whether the use of PRB coal, lower-sulfur eastern coal, or biomass would affect emissions of pollutants other than $SO_2$.

KDAQ's oversight is particularly troubling because there is strong reason to believe that the use of a cleaner feedstock would impact a range of pollutants. For example, low-sulfur fuels would impact the amount of sulfuric acid mist resulting from the plant, as well as $PM_{2.5}$ emissions, because $SO_2$ contributes to formation of secondary particulate matter. Thus, the required $PM_{2.5}$ BACT analysis – and any SAM BACT analysis if required – must consider the use of lower-sulfur fuels as well. Other components of particulate matter also may vary by fuel, and thus feedstock alternatives may be appropriate for consideration of PM/ $PM_{10}$ BACT.

The amount of $NO_x$ is also dependent on the fuel source. As EPA has noted, combustion of biomass generally results in lower PM and $NO_x$ emissions than coal. 74 Fed. Reg. 41, 47 (Jan. 2, 2009). And although they are not dispositive, the AP-42 emission factors suggest that the burning of subbituminous coal (such as PRB coal) generally has lower emissions of $NO_x$ than bituminous coal.[32]

In sum, before rejecting the use of cleaner fuels for the facility's feedstocks due to cost considerations, KDAQ must spread the cost of this control option across all pollutants that would be reduced through the use of that option. Unless and until that analysis has been done, the BACT analysis remains incomplete.

### 3. Petroleum Coke

The BACT analysis of the Kentucky Syngas facility's feedstocks is deficient for the additional reason that KDAQ failed to consider whether petroleum coke should be prohibited as a feedstock, on the basis that cleaner feedstocks are available and will result in greater reduction in emissions. The sulfur content of the petroleum coke to be used for this facility is substantially greater than that of the high-sulfur coal that will also be used as a feedstock. *See* Application at 2-8. Petroleum coke also frequently has higher concentrations of certain heavy metals, such as nickel and vanadium.[33] Given the higher potential emissions resulting from the use of petroleum coke, KDAQ must consider whether petroleum coke should be prohibited as a feedstock (or, alternatively, whether there should be a limit on the percentage of feedstocks from petroleum coke) in setting BACT limits. KDAQ's failure to do so renders the Permit unlawful. In fact, the Permit contains no limit on the percentage of petroleum coke that the plant might process, and the Applicant claims to be fuel flexible with the ability to process up to 100% petroleum coke.[34]

[32] Exhibit 19, AP-42, External Combustion Sources, § 1.1, at 1.1-16 to -17.

[33] Exhibits 20a & 20b, Crude Quality Inc. *Report to Stakeholders: Report on December 2007 Results and Results to Date Summary Report* (Feb. 4, 2008); *see also* Crudemonitor.ca. December 2007 Heavy Crude Report and December Light Crude Report.

[34] *See* Exhibit 11, Gosney e-mail.

The implications of this use of petroleum coke must be considered when calculating PTE and in a BACT analysis of cleaner fuels.

Although Petitioners raised this issue in their comments, KDAQ refused to conduct any further BACT analysis, or impose any additional limits in the Permit. Instead, the agency stated that "Kentucky Syngas evaluated emissions using 100% petroleum coke and the emissions limits proposed for the facility account for such use." RTC at J-34. KDAQ further stated that "the proposed BACT emission limitations . . . for the project are considered 'worst-case' despite the fact that they were established based on . . . the design feedstock mixture percentage of 2:1 coal to petroleum coke." RTC at J-34. In other words, KDAQ set the facility's BACT limits based on the use of 100% petroleum coke – a feedstock that would result in even greater emissions than those resulting from Eastern bituminous coal. In doing so, KDAQ has flipped the BACT requirement on its head: rather than setting limits that are "based on the maximum degree of reduction of each pollutant . . . achievable for [the] facility," 42 U.S.C. § 7479(3), KDAQ has apparently established *weaker* emission limits based on the dirtiest potential feedstock mixture (100% petroleum coke). The Administrator must object to this misapplication of the BACT standards.

### B. KDAQ and the Applicant Failed to Consider Clean Fuels/Clean Processes Alternatives For Several Emission Units.

KDAQ also violated the clean fuels/clean processes standard by failing to consider the exclusive use of natural gas as BACT for the following emission units: EU-01, -02, -13, -08, and -09. In a recent order, the EPA Administrator reaffirmed that state permitting agencies must consider natural gas as a clean fuel alternative to dirtier coal-based fuels such as syngas or SNG. *In re Cash Creek Generation*, Order at 7, 9. Here, the proposed facility includes several emission units which can use either SNG or natural gas as its primary fuel, but for which no clean fuels/processes analysis was performed. In order to satisfy the Act's clean fuels requirement, KDAQ must consider whether the exclusive use of natural gas represents BACT for those emission units. The agency's failure to consider clean fuels for the above-mentioned units renders the Permit legally inadequate.

In its Response to Comments, KDAQ claims that it did not need to conduct a clean fuels BACT analysis because the emission limits for firing SNG and natural gas are identical. RTC at

J-24. But the mere fact that KDAQ established an identical emission limit for these two fuels does not mean that this limit represents BACT. A proper clean fuels analysis was required to determine whether the emission limit would have been lower with a prohibition on the use of SNG. And even assuming, as Kentucky Syngas asserts, that the *combustion* of SNG would result in fewer emissions than natural gas, the *production* of coal- or petcoke-based SNG creates more emissions than natural gas. Thus, allowing the use of SNG for these emission units violates the BACT clean processes standard. [35]

## VII. THE EMISSIONS ESTIMATES FROM THE FLARE AND BACT FOR THE FLARE ARE IN ERROR.

The Administrator must object because the Applicant and KDAQ relied on a faulty and incomplete assessment of emissions from active flaring, as well as a flawed BACT analysis and inadequate BACT limits for the flare. Errors in estimating emissions from the flare are significant because the agency used these estimates to support its determination that the proposed facility is a minor source of VOCs, $H_2S$, and HAPs. The flawed BACT limits, in turn, fail to ensure the maximum reduction in pollution from the flare.

### A. PTE Must Include Startup, Shutdown and Malfunction Emissions, Including Those From Active Flaring.

The applicable Kentucky provision defines PTE as follows:

> (a) The maximum capacity of a stationary source to emit a pollutant under its physical and operational design, in which:
>
> 1. A physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, is treated as

[35] Likewise, because diesel may have cleaner-burning alternatives (such as natural gas), KDAQ must also consider clean fuels in its BACT analysis for the firewater pump (EU-06) and standby generators (EU-07). The Applicant's claim that diesel is necessary for these units, RTC at J-24, is unsupported by any evidence. And the Applicant's claim is contradicted by the recently-permitted Cash Creek facility, which would use natural gas for its firewater pumps and standby generators. *See* Exhibit 21, Permit Statement of Basis, Permit No. V-09-006, Cash Creek Generating Facility, at 6 (Mar. 1, 2010) (excerpt). KDAQ and the Applicant were required to consider clean fuel alternatives to diesel, and their failure to do so renders the Permit unlawful.

> part of its design if the limitation is enforceable as a practical matter; and
>
> 2. This definition does not alter or affect the use of this term for other purposes of the Clean Air Act, 42 U.S.C. 7401-7671q, or the term "capacity factor" as used in the Acid Rain Program.
>
> (b) For the PSD and NSR programs, the maximum capacity of a stationary source to emit a pollutant under its physical or operational design, in which:
>
> 1. A physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, is treated as part of its design if the limitation or the effect it would have on emissions:
>
> a. Is federally enforceable . . . .; and
>
> 2. Secondary emissions are not counted.

401 KAR 51:001 Section 1(190); *see also* 401 KAR 51:001 Section 1(142) (SIP-approved version) (providing substantively similar definition of PTE). This provision requires that PTE reflect the *maximum* capacity to emit a pollutant. Because flares emit pollutants and contribute to this maximum capacity, their emissions must be included in PTE. Nowhere does the definition make a blanket exception for emissions during startups, shutdowns, and malfunctions ("SSM") of the facility. This definition also requires that, to the extent that the applicant or agency claims that maximum capacity to emit is constrained in any way, that constraint must be explicitly set forth in the permit as a *physical or operational* limit – i.e., a specific limit on fuel, hours of operation, or pollution control equipment operating parameters – that is practicably enforceable.

Accurately estimating PTE is crucial in determining whether PSD review is required for various pollutants. Determining if BACT applies to a particular pollutant first involves calculating whether the source has the potential to emit that pollutant in significant amounts. 401 KAR 51:017 Section 8(2). This process entails adding together the PTE of each emissions unit. The Kentucky regulations define "emissions unit" broadly to include "any part of a stationary source . . . that emits or has the potential to emit a regulated NSR pollutant." 401 KAR 51:001

Section 1(64). Because flares emit regulated NSR pollutants, they are among the emissions units at a facility. *See* Permit at 5 (describing flare as "Emission Unit 01"); *see also In re: ConocoPhillips Co.*, 13 E.A.D. 768, 773-74 (EAB June 2, 2008) (recognizing that flares are "among the [] *emissions units* that will contribute to the increase" in pollutants counted towards triggering PSD or nonattainment new source review) (emphasis added). Moreover, flares emit pollutants while operating pursuant to their "physical and operational design," 401 KAR 51:001 Section 1(190), which is aimed at controlling emissions from the larger facility, e.g., during periods of SSM. The PTE of a source must therefore reflect the maximum capacity of that flare to emit a pollutant during active flaring. It follows that all active flaring emissions must be included in the source's PTE.

EPA has confirmed that facility SSM emissions must be included in PTE calculations. In a recent response to a Title V petition, which specifically dealt with pollution from flares, the Administrator objected to the permit because it failed to fully take account of flaring emissions, either by including them in PTE or limiting them under federally enforceable permit conditions. *In the Matter of BP Products, North America, Inc., Whiting Business Unit*, Order Partially Denying and Partially Granting Petition for Objection to Permit, October 16, 2009 ("BP Title V Order"), at 5-7 (Exhibit 22). Likewise, in recent comments on a PSD permit, EPA stated that "[t]he regulations do not provide exemptions for excluding startup emissions from a facility's Potential to Emit (PTE)."[36] In addition, EPA has issued guidance stating:

> The consensus is that for the purposes of determining PTE in the New Source Review (NSR) and Title V programs, EPA has no policy that specifically requires exclusion of "emergency" (or malfunction) emissions. Rather, *to determine PTE, a source must estimate its emissions based on the worst case scenario taking into account startups, shutdowns, and malfunctions.*[37]

If SSM emissions could be excluded from PTE, the purpose of PSD/NSR – to protect air quality by requiring stringent control of polluting facilities – would be significantly weakened.

[36] Exhibit 23, EPA Comments on the Draft Prevention of Significant Deterioration (PSD) Permit, AP-5873, to Construct at Medicine Bow Fuel and Power's Industrial Gasification and Liquefaction Plant, August 4, 2008.

[37] *See* Exhibit 24, Letter from Steven C. Riva, EPA to William O'Sullivan, Division of Air Quality, N.J. Dept. of Environmental Protection, February 14, 2006 (emphasis added).

Facilities, moreover, would have little incentive to minimize SSM to the greatest extent possible in the design and operation planning stages.

With respect to physical or operational limits on PTE, courts have emphasized the need to ensure that any constraints assumed for PTE are grounded in enforcement reality. *United States v. Louisiana-Pacific Corp.*, 682 F. Supp. 1122 (D. Colo. 1987);[38] *see also Weiler v. Chatham Forest Products*, 370 F.3d 339, 241 (2nd Cir. 2004) ("In short, then, a proposed facility that is physically capable of emitting major levels of the relevant pollutants is to be considered a major emitting facility under the Act unless there are legally and practicably enforceable mechanisms in place to make certain that the emissions remain below the relevant levels."). The *Louisiana-Pacific* court described PTE as "the cornerstone of the entire PSD program," and observed that allowing illusory and unenforceable limits to curtain PTE would create a loophole that could effectively wipe out PSD requirements entirely. 682 F. Supp. at 1133. To include enforceable limits on PTE, a permit must create mandatory obligations (standards, time periods, methods). Specifically, a permit condition must: (1) provide a clear explanation of how the actual limitation or requirement applies to the facility; and (2) make it possible for KDAQ, EPA, and citizens to determine whether the facility is complying with the condition. *See Sierra Club v. Public Serv. Co.*, 894 F. Supp. 1455, 1460 (D. Colo. 1995); *see also* BP Title V Order at 7 (upholding requirement that PTE calculations be made enforceable through adequate permit limits). Under the relevant Kentucky SIP provision, case law, and EPA guidance,[39] the only limits that are enforceable for purposes of PTE are specific restrictions on operation and design set forth in the permit, adherence to which can be verified by authorities. Permit conditions requiring monitoring only, and not specifying measures by which emissions will be kept below their permitted limits, do not constitute sufficient limits on PTE. *See* BP Title V Order at 8, 9-10.

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[38] The specific holding of *Louisiana-Pacific* – that limits on PTE must be federally enforceable – has been overruled by authority stating that the limits may also be "enforceable as a practical matter." *See National Mining Ass'n v. EPA*, 59 F.3d 1351 (D.C. Cir. 2004) (holding that limits on PTE must be enforceable as a practical matter but need not necessarily be federally enforceable). But the basic principles concerning PTE articulated in *Louisiana-Pacific* remain standing.

[39] 401 KAR 52:001(56); *Louisiana Pacific, supra* and *Weiler, supra*; Exhibit 25, Terrell Hunt, Associate Enforcement Counsel, EPA Air Enforcement Division, and John Seitz, Director, EPA Stationary Source Compliance Division, "Guidance on Limiting Potential to Emit in New Source Permitting," (June 13, 1989).

## B. KDAQ Failed to Estimate the Full Emissions From Active Flaring.

During the public comment period, Petitioners raised concerns with potential emissions from active flaring, which will occur when the facility goes through SSM. *See, e.g.*, Comments at 29-32. Petitioners specifically commented on the complete omission of flaring emissions during unplanned shutdown and malfunction. *See, e.g.*, Application, Appx. C-3 (providing emissions estimates only for steady-state operation, cold plant startup, total plant shutdown, and gasifier rotations); SOB at 31 ("The flare at the Kentucky Syngas facility will receive various vent streams during routine gasifier rotations, cold plant startups, and total plant shutdowns.").

Petitioners further explained that including malfunction-related emissions in PTE is especially crucial for flares because their purpose is to control the release of gases from process units, including during malfunctions. In the Permit, KDAQ acknowledges this point, stating that the flare will be used for malfunction events, i.e., "flaring incidents," and that emissions during those incidents will be large. A Flaring Incident is defined as a "non-routine flaring event that produces more than 500 lb $SO_2$/day above permit limits and accompanies the unscheduled shutdown of a gasi[fier] or syngas processing train or a malfunction of a process unit generating process gas routed to the flare." Permit at 12.

Notwithstanding the legal mandates to account for emissions related to malfunctions and unplanned shutdowns, and the fact that such emissions will be substantial, the permit application includes no estimate for malfunction-related emissions. There are no estimates at all of the frequency of, duration of, or emissions resulting from emergency and upset conditions.[40]

KDAQ responded to Petitioners' comments by arguing repeatedly that PTE excludes malfunctions. *See, e.g.*, RTC at J-17 ("Unplanned startup, shutdown, and malfunction events are

[40] Even one upset per gasifier per year can result in tons of additional $SO_2$ and PM, and additional emissions of $NO_x$, CO, VOC, H2S, COS, mercury, hydrochloric acid, hydrofluoric acid, and other pollutants. This is because certain process conditions are typically present when a malfunction occurs and there is reduced efficiency of flaring when a large amount of gas needs to be flared very quickly. As a result, much higher emissions are seen during flaring from malfunctions (when the process is not controlled) than flaring during planned startup shutdown when the process is predictable and controlled. For example, the acid gas removal unit ("AGR") vents to the flare during AGR malfunction. Application, Appx. C-25, at 105. In that circumstance, sulfur from the gas will not be fully removed by the AGR, and methanol-rich gas might be vented to the flare. Also, although the timing of when a malfunction may occur on an operating gasifier is uncertain, when it occurs the gaseous contents of the gasifier must be exhausted via the flare. This has implications for the sulfur content of the gas being flared. Thus, emissions from the flare will depend on the process conditions such as the chemical composition of the gasifier contents.

not required to be accounted for in a facility's potential to emit."); *id.* at J-50 ("PTE estimations are based on operating the source as it is intended to be operated normally, not on unplanned events or malfunctions . . . ."); J-56 (same). KDAQ's position is erroneous. It ignores the regulation's unit-by-unit PTE summation process outlined above. More importantly, KDAQ has staked out a position directly contrary to EPA's interpretations regarding PSD applicability. As the Administrator recently explained, malfunction-related emissions must be included in PTE. BP Title V Order at 5-7. KDAQ therefore erred in concluding that PTE excludes malfunctions and unplanned shutdowns.

KDAQ's further claim, that the Permit "does address flare emissions" from malfunctions because emission limits are the same, RTC at J-50, fails to grasp the importance of properly estimating PTE. Properly estimating a facility's potential to emit is necessary to determine whether that facility is subject to full PSD review. This is especially relevant for the Kentucky Syngas facility, which KDAQ concluded is not subject to full PSD review for VOCs, $H_2S$, and other pollutants. SOB at 40-41.

The Permit's failure to address flaring emissions in the event of malfunctions and unplanned shutdowns is especially troubling given the faulty assumptions built into the Permit. Kentucky Syngas and KDAQ both blithely assumed that only sweet syngas will be vented to the flare because all sulfur-rich gases will be routed through the AGR unit. *See, e.g.*, Application at 1-7, 2-21; SOB at 4. Neither accounted for the emissions implications of an AGR malfunction. Given that the AGR unit's pressure relief valves ("PRVs") vent directly to the flare, *see* Application, Appx. C-25, at 105, when the AGR unit malfunctions, the flare will inevitably begin flaring sour syngas or sulfur-rich process gases. None of this, however, has been factored into the emissions estimates or the Permit more generally.[41] Because KDAQ failed to address the malfunction-related emissions of the flare, the Permit is unlawful.

[41] KDAQ responded to Petitioners' comment by arguing that "these PRV releases are *not necessarily all* sour syngas and sulfur-rich process gas." RTC at J-51 (emphasis added). Although this statement implicitly concedes that *some* sour syngas will be vented to the flare, KDAQ emphatically refused to alter the Permit. *See id.* ('The Division notes that no changes were made to the permit as a result of this comment.").

### C. The Permit Lacks Enforceable Conditions to Ensure Low Levels of Flaring Emissions.

In addition to failing to properly estimate flaring emissions, the Permit lacks specific terms and conditions necessary for ensuring consistency with the assumptions of the application and minor source determinations. In other words, the Permit lacks enforceable limits on the flare's PTE. While the permit contains annual limits of 604.5 tpy CO, 19.5 tpy $NO_x$, and .9 tpy $SO_2$, these reflect the PTE calculations. Permit, Cond. 2.a., at 7; Application, Appx. C-3, at 6-12. These limits cannot be met given that there will be malfunction emissions and those emissions were not included in the PTE calculations. These emissions limits are not backed up by any enforceable design or operational limits, and thus fail to control PTE.

First, pollutants such as VOCs, which may be present in the flare gas but are not mass conserved, are estimated as follows: VOCs emitted = inlet VOC mass in the flare gas x (1-control efficiency). *See* Application, Appx. C-6, at 8. Since the VOC control efficiency is not being measured at all, this calculation is unverifiable. In short, there is no way of ensuring that the sourcewide VOC limit of 36 tpy is being met. *See* Permit at 91.

Second, while there is much reliance in the Application and SOB on a "proprietary low sulfur startup" procedure, SOB at 74, there are no concrete permit limits requiring such a procedure. *See* Permit at 5. Since the Application, PTE emissions calculations, and Statement of Basis relied on this low sulfur startup procedure, the full procedure must be included as an enforceable operating limit. When Petitioners raised this issue in their comments, KDAQ responded that *some* of the elements of this procedure are in the Permit. RTC at J-58. The agency, nevertheless, admitted that many of those elements have not been included in the Permit, and will only be made available in a to-be-determined SSM plan. *Id.* As explained above, KDAQ's failure to release this plan and subject it to public review and comment violates CAA requirements. *WE Energies*, Order at 23-27; *RockGen Energy Center*, 8 E.A.D. at 552-55. Withholding this plan violates the Act for the additional reason that it renders the PTE limits unenforceable. Moreover, the Permit explicitly states that the SSM plan may be subsequently changed without agency notice or approval. Permit at 13 ("The permittee may periodically revise the SSM plan for the affected source as necessary to satisfy the above requirements or to reflect changes in equipment or procedures associated with the flare. The permittee may make such revisions to the SSM plan without prior approval by the Division."). Likewise, to the extent compliance with VOC limits rests on compliance with CO emission limits for the flare (*see* Permit at 91), that limit is unenforceable because, among other things, it relies on a to-be-determined flare monitoring plan. Permit at 11.

Third, although the PTE calculations assume one event per year for cold startups and one event per year for total plant shutdowns (Application, Appx. C-3, at 10), the Permit only limits hours per startup or shutdown event; it does not place a limit on hours per year or events per year (other than a limit for gasifier rotations). Permit at 6. Thus, because the Permit does not include the same limits on flaring that were assumed in the PTE calculations, the limits on PTE are unenforceable.

Finally, the Permit requirements do not limit the number of unplanned shutdown and malfunction events, nor the duration of malfunction events, and thus does not functionally limit emissions during such events. The only requirement related to malfunction flaring events is the need to perform a Root Cause Analysis, but this contains no concrete steps or requirements. The Permit requires a Root Cause Analysis of each Flaring Incident. Permit at 12. As mentioned above, a Flaring Incident is "produces more than 500 lb $SO_2$/day above permit limits." *Id.* For a permit that limits $SO_2$ to 33.8 lb/hr and .9 tpy, 500 lbs per day is significant (25% of the annual limit). And the provisions regarding flaring incidents make clear that the Permit is tacitly allowing emissions during such events, emissions that exceed permit limits.

The monitoring provisions that could identify exceedances of 500 lbs/day $SO_2$ in these permit limits are missing. No minimum detection limits at all are identified for monitoring flare gas flow or the minimum concentration of chemicals detectible within flare gas. There is no requirement that the Applicant even be able to detect 500 lbs of $SO_2$ in the flare gas per day. In order to detect 500 lbs/day, monitoring equipment must be capable of detecting the equivalent of 0.0058 lbs/second sulfur compounds within the flare (500 lbs/day / 24 hours /day / 60 mins/hour / 60 seconds/min = 0.0058 lbs/second).[42]

Nor does the Permit set any minimum detection limit for either the volume of gas flow (detected by a flow monitor), the concentration of gases within that volume (detected by other flare equipment such as continuous gas chromatography), nor any flow verification methods.

[42] Note that the sulfur compounds present inside the flare producing the mass of $SO_2$ coming out will be in a different form, such as $H_2S$ inside the flare. These have different molecular weights compared to the $SO_2$ coming out of the flare.

Methods for meeting necessary detection limits are readily available and in use, and have already been explicitly required in the Bay Area Air Quality Management District ("BAAQMD") flare monitoring regulation 12-11. *See* Exhibit 26, BAAQMD Regulation 12-11, Section 12-11-501 Vent Gas Flow Monitoring. They require installation of equipment capable of detecting gas flow with a minimum detection limit of 0.1 feet/second, and continuous monitoring capability of a range of gases from 0.5 to a maximum of 275 feet/second (because flares are designed to emit drastically varying amounts of gases from low to high).

The BAAQMD regulations also require specific methods, detection limits, and verification methods for detecting sulfur and VOC gases, as does BAAQMD Rule 12-12 flare control regulation. Such minimum detection limits are necessary if any emission limit for the flare at all in the Permit is to be met. With no minimum detection limit for monitoring equipment, constant flaring can occur without any detection or reporting. Furthermore, without a maximum detection limit, emissions from very large events could be easily underreported, because monitoring equipment has been known to "peg" high, where it cannot go any further. This lack of minimum detection limits means that the permit cannot be verified to meet the VOC limit of 36 tpy. Because the Permit lacks enforceable limits on the flare's PTE, the Administrator must object.

**D. The Flare Permit Measures Are Not BACT.**

No proper BACT analysis was performed for the flare, and, as a result, the Permit does not require BACT, does not adequately limit shutdown and emergency emissions, and sets emissions limits for the flare that are insufficient to meet BACT requirements. BACT is not just an emissions limit but can involve operational or design requirements. 401 KAR 52:001(56). There are several widely used methods to control emergency flaring emissions. These include, but are not limited to, a flare minimization plan, a root cause analysis, and treating all gases routed to the flare.

First, a complete flare minimization plan must be developed for the facility, reviewed by KDAQ, subjected to public review and comment, and included in the permit record. *See RockGen Energy Center*, 8 E.A.D. at 552-55 (requiring the permitting agency to subject any provisions relied upon for permitting to public notice and comment). Moreover, development of such Plans at this time (*i.e.*, when the plant is in the design stages), is necessary since minimization of flaring is not simply an operational issue to be addressed after the plant is built. Rather, flare minimization requires changes in plant design, material selection, instrumentation and controls, and other factors that must be designed and planned for now—before the plant is built—to truly minimize flaring from the plant. Unfortunately, the Permit contains no such minimization plan. This contrasts with other air permits, which require much more specific methods and, therefore, establish BACT. These include the detailed assessments required by the BAAQMD and South Coast Air Quality Management District (SCAQMD) flare monitoring and control regulations, and, for example, the Flare Minimization Plan for the Shell refinery in Martinez, California. *See* Exhibit 26, BAAQMD Flare Monitoring and Flare Control Rules -- Regulation 12-11; Exhibit 27, *id.*, Regulation 12-12; Exhibit 28, SCAQMD flare monitoring and control regulation – Rule 1118; Exhibit 29, *Shell Martinez Refinery, Regulation 12 Rule 12, Flare Minimization Plan, Redacted Version, Revised March 25 2007, Submitted to: Bay Area Air Quality Management District.*

Although the Permit includes a Root Cause Analysis requirement, that cannot substitute for the lack of a Flare Minimization Plan. First, the Root Cause Analysis is a "Monitoring Requirement," Permit at 12, and not an operating limitation. Second, it contains no concrete steps or measures to reduce flaring. It requires only that the permittee "take reasonable steps to correct the conditions that caused or contributed to the incident, and to further minimize emissions from flaring." Permit at 12. It requires a corrective action program only "if necessary . . . to minimize the likelihood of a recurrence of the cause(s) of the incident." *Id.* Such vague and subjective requirements are unenforceable as a practical matter.

In its Response to Comments, KDAQ suggests that the elements of a flare minimization plan are incorporated into the Permit through the following: development of an "[SSM] plan, flare monitoring plan, and root cause analysis procedures." RTC at J-62. But this response merely underscores the Permit's deficiencies. As noted above, a root cause analysis cannot serve as a substitute for a flare minimization plan. And to the extent KDAQ's flare minimization plan consists of two documents that have not been drafted – the flare monitoring and SSM plans (not to mention root cause analysis procedures that remain to be drafted) – the agency's plan violates CAA requirements. As the Environmental Appeals Board stated in a similar situation, rather than rely on post-hoc submissions, the "procedures for operating and maintaining the affected sources generating process gas routed to the flare during periods of SSM and a program of corrective action" must be spelled out in the permit itself. *See RockGen Energy Center*, 8 E.A.D. at 552-55. In short, KDAQ must require that all provisions of the flare minimization plan be incorporated into the Permit and subject to public comment. Substantively, to meet BACT requirements, the BAAQMD, SCAQMD, and Shell Martinez provisions should be used in establishing an adequate minimization plan.

The Permit's flaring emission limitations fail to meet BACT requirements for other reasons as well. For example, the Permit allows generalized compliance and alternatives to complying with federal regulations, and allows infrequent and inadequate monitoring (such as visual detection on a weekly or longer basis). These simplified versions of monitoring requirements and emissions limitations do not meet rigorous BACT standards for detection limits and for ensuring that all flare events are detected, measured, recorded, reported, and tallied, within a specific annual limit. No top-down BACT determination was made comparing these practices to BACT. The Permit provides broad loopholes, and identifies general terms without the means to measure whether these terms are met (such as flame stability, low flow conditions).

The Permit does include emission limits for CO, $NO_x$, and $SO_2$ (Permit at 7) from flaring on an hourly and annual basis, but no top-down BACT analysis was provided demonstrating these levels as BACT for hourly and annual emissions. Moreover, vagueness in the design, monitoring, and other permit requirements results in requirements lacking the specificity necessary to ensure that these levels are met. Furthermore, the 14,591 lb/hr 8-hr average CO limit is very large, which is set to "ensure compliance with the CO NAAQS," but this high number does not represent a BACT level, and no BACT determination was provided to support this level. Likewise, no BACT determination was provided for the $H_2S$ (165ppm) and $SO_2$ (250 ppm) flare limits.

## VIII. THE PERMIT FAILS TO MEET NESHAPS AND MACT REQUIREMENTS.

The Administrator must object because the Permit continues to lack appropriate case-by-case MACT determinations for HAPs, instead relying on an erroneous minor source determination. HAPs are regulated under Section 112 of the Clean Air Act. 42 U.S.C. § 7412. The purpose of the Clean Air Act's HAPs program is to force the stringent control of these highly detrimental pollutants because they could "cause, or contribute to, an increase in mortality or an increase in serious irreversible[] or incapacitating reversible[] illness." *New Jersey v. EPA*, 517 F.3d 574, 577 (D.C. Cir. 2008) (quoting legislative history of Section 112). Due to the importance of controlling HAPs, it is crucial that sources accurately identify HAP emissions. If, as here, a source feigns its way into the minor source category and thereby illegally circumvents the requirement for stringent controls, it defeats the purpose of the MACT program.

The first major error in the MACT analysis for the Kentucky Syngas Permit is that it relies on faulty and unsupported estimates of PTE. The Applicant did a potential to emit calculation for HAPs and concluded that the facility will be a minor source, reaching neither the 10 tpy level for an individual HAP nor the 25 tpy level for collective HAPs that triggers MACT. Application at 4-7. There are numerous errors with the Applicant's calculations, most notably the failure to calculate maximum (worst case) emissions. The Permit then compounds the errors by failing to reflect the emission calculations in enforceable permit limits.

The Applicant makes clear that it calculated HAPS using PTE. "Potential to emit calculations by emissions source were performed . . . ." Application at 4-7. The two major errors in the PTE calculations were failure to account for HAP emissions during malfunction and emissions calculations of fugitive methanol from the AGR that assume unreasonably high control efficiencies.

The Permit translates these calculations into only a very few permit conditions purportedly limiting HAPs. First, the Permit only sets a limit on methanol. In other words, not only are all combined HAP emissions unaccounted for, but the Permit fails to limit combined HAP emissions. KDAQ and the public are left with no accurate data on total HAP emissions, no monitoring of total HAP emissions, and a permit with no compliance and enforcement mechanisms on total HAP emissions.

Regarding permit conditions that limit HAPs, the Application states:

> To preclude applicability of the NESHAP program incorporated by reference at 401 KAR 63:001, Kentucky NewGas is requesting specific federally enforceable operating requirements for the equipment leak components in the AGR process area (FS-2) and for the methanol storage tank (EP-11). Implementing these voluntary operating restrictions will allow the facility to demonstrate compliance with the proposed synthetic minor emission limitation for the maximum single HAP - 9.0 tpy for methanol.

Application at 4-9. These statements underscore the errors. First, the operating requirements do not provide any assurance of staying below the major source threshold and do not provide an emission limit that is enforceable from a practical perspective. Second, there is only one Permit condition that limits individual HAPs: "To preclude the applicability of 40 CFR 63, Subpart B, source-wide emissions of methanol shall be less than nine (9) tons per twelve (12) month rolling total." Permit at 92. And KDAQ concluded that the NESHAP program was non-applicable. SOB at 51.

Moreover, compliance with this permit condition is based upon the very same fugitive methanol HAPS Leak Detection and Repair control efficiency for the AGR that was used to calculate the post-control expected emissions for fugitive methanol HAPS from the AGR. In other words, compliance with the Permit limit is demonstrated by repeating the PTE calculations. This is completely circular. Consequently, the emission estimates and resultant permit conditions fail to comply with applicable law. In its Response to Comments, KDAQ made no effort to correct these Permit deficiencies. Compliance with these Permit limits continues to consist of nothing more than the PTE calculations themselves.

## A. The PTE Calculations Are Not Worst Case

### 1. Failure to Calculate and Count HAPS from Flaring Malfunctions

PTE calculations for HAPs must account for *all* HAP emissions. The PTE calculations for the Kentucky Syngas facility are incomplete because they fail to include HAP emissions during malfunctions or unplanned shutdowns. The Application acknowledges this failure to include HAPs from malfunction flaring events, stating that it only covers "Flaring During Planned SU/SD Events." Application at 4-10. Since the units with the highest potential for HAP emissions (i.e., the AGR) have pressure relief valves (PRVs) that are routed to the flares during malfunctions, the most significant HAP emissions during malfunction or unplanned shutdown will be seen at the flare. Application, Appx. C-25, at 105. Further, unlike planned startups and shutdowns, malfunctions constitute the operating scenario when the flare will be receiving the process gases with the highest HAP emissions profile. Depending on the unit or units at the facility that are in breakdown mode, there is no assurance that the HAPs will be removed or controlled before flaring. Application at 7-4. Again, the AGR is the source of the highest HAP emissions, which Kentucky Syngas admits has the potential for 21.39 tpy uncontrolled emissions of methanol. During a malfunction event, routing one of the high methanol process gas streams from the AGR to the flare poses the risk of high methanol emissions. While routing the PRVs to the flare is viewed as 100% control of the PRVs for fugitive HAP purposes (Application, Appx. C-25, at 105), no increased methanol emissions from the flare are counted. Considering that the flares will be venting .04 tpy of methanol during *planned* startups and shutdowns (when it is only receiving gas streams that have been cleaned), these malfunction-related methanol emissions from the flare will likely contribute more than 2 tpy, thus rendering this facility a major source for HAPs.

KDAQ's treatment of HAPs is wholly inconsistent with MACT requirements, which require (a) consideration of emissions during periods of startup, shutdown or malfunctions when establishing the proposed limit, and (b) a demonstration of how emissions are estimated to assure the source is below major source levels. As EPA recently stated:

> The State must include a discussion of how emissions during periods of startup, shutdown or malfunctions were considered in establishing the potential to emit HAP for Unit #13, and if periods of startup, shutdown or malfunctions were not considered, the State must explain how the source will comply with the potential to emit limitation if such events occur in any 12-month period.

Exhibit 30, EPA, Region 8 Objections to Proposed Title V Renewal Operating Permit for Big Stone Power Plant in South Dakota and cover letter (Jan. 22, 2009) ("Big Stone Objection"), Objections at 11. The wholesale disregard of malfunction and unplanned shutdown emissions in the Application, SOB, and Permit for Kentucky Syngas does not meet the requirements of EPA's Big Stone Objection. By omitting the emissions from flaring during malfunction, the potential to emit calculations are erroneously low, and the facility is a major source thresholds for HAPs.

### 2. Unsupported Control Equipment Efficiencies for Methanol

As noted above, methanol is the only HAP that is actually limited by the permit. *See* Permit at 92 ("To preclude the applicability of 40 CFR 63, Subpart B, source-wide emissions of methanol shall be less than nine (9) tons per twelve (12) month rolling total."). With respect to methanol, the single HAP with the largest potential emissions, the Applicant again underestimated emissions, resulting in a PTE that is artificially below the major source threshold for an individual HAP. For this reason, the claim that Kentucky Syngas is not a major source of HAPs must be rejected.

The vast majority of calculated HAPs (not including the omitted malfunction emissions discussed above) come from fugitive leaks of methanol at the AGR. The uncontrolled PTE of methanol from the AGR is calculated to be 21.39 tpy. This source of HAPs is also the largest source of HAPs from the facility and the source most likely to push the facility over the edge for both individual HAP emissions of 10 tpy and combined HAP emissons of 25 tpy. (These emissions are in addition to the 5.65 tpy of methanol that the AGR will emit from the vent.) In its Application, Kentucky Syngas claimed that controlled methanol emissions from AGR Fugitive Equipment Leaks will be 2.22 tpy. Application at 4-10. This assumes an average control efficiency of 90% and specific control efficiencies of 75%, 85%, of 97% for various sources of leaks, not considering 100% for the PRVs due to the routing to the flares. Application at 4-11; *id.*, Appx. C-25, at 105. These are extraordinarily high assumed control efficiencies from a Leak Detection and Repair ("LDAR") program. An assumption of 90% control from an LDAR program is unreasonable. Kentucky Syngas should instead rely on EPA's Protocol for Equipment Leak Emissions Estimates. For SOCMI facilities with LDAR programs and quarterly monitoring similar to the monitoring proposed by the Syngas permit, leak rates are calculated to be in the 45%-67% range instead of the 75%-95% calculated by Kentucky Syngas. Exhibit 31, EPA Protocol, Table 5-2.[43] Moreover, the LDAR program included in the Permit was a mere few pages and insufficient to assure such stringent control efficiencies assumed by the Applicant and KDAQ. For all these reasons, the 90% assumption is unrealistic and unenforceable.

Finally, as explained below, compliance with the 9 tpy permit limit is based upon the very same fugitive methanol HAPS LDAR control efficiency for the AGR that was used to calculate the post-control expected emissions for fugitive methanol HAPS from the AGR. This is completely circular and allows for a self-fulfilling prophecy in terms of compliance. A permit cannot be based on such faulty calculations and emissions limitations that do not assure compliance. *See* Baard Expert Report at 36-37 (attached as Exhibit 32).

**a. Undercounting From The AGR**

The application describes the exhaust stream from the Rectisol AGR unit. The description includes CO2 at 97.72 mol%, CO at .31%, COS at .0002%, $H_2S$ at .0003%, and methanol at .01%. Application, Appx. C-7, at 32. Rectisol is a flexible process that can be

[43] Unless of course, Kentucky Syngas agrees that it is subject to the NESHAP regulation, which contains concrete enforceable requirements that achieve 75%-93% control efficiencies, as shown by the third column. *Id.*

customized a number of different ways. It also has been used in many different applications since it was developed in the 1950s. Composition of exhaust streams varies somewhat depending on the process configuration and inputs. Nonetheless, based on emissions from other Rectisol units, the additional content of the exhaust stream can be presumed to contain some other VOCs which are also a HAP. One recent draft construction permit, for the Rentech facility in Illinois, concluded that potential methanol emissions from the Rectisol unit (including the solvent stripper vent and fugitive emissions from leaking components) exceeded the 10 TPY HAP threshold, triggering a MACT analysis. Another recent BACT determination, for the Rectisol vent from the Air Products Baytown facility in Texas, included a limit for methanol emissions of 1.3 lbs/hr.[44] Regeneration of used methanol is included as part of the Rectisol unit. Regardless of the process specifics, it is clear that both fugitive emissions of methanol and direct and fugitive emissions of other VOCs were omitted from the application and have not been accounted for in the Permit.

#### b. Other Fugitive Components

The fugitive emissions calculations for the Kentucky Syngas facility were based on: (1) SOCMI emission factors for each type of component and service (gas, liquid) from TCEQ guidance; (2) the number of each type of component; and (3) the control efficiency that will purportedly be achieved by the facility's LDAR program. Application, Appx. C-24 to C-27, at 104-106. The Permit does not require that any of this information be corroborated, but rather allows the use of the same emission factors and other assumptions as utilized in the emissions calculations. Permit at 92-94. Sole reliance on emission factors and control efficiencies, for both emissions calculations and ensuring compliance with emissions limits, is improper.

## B. The Permit Lacks Enforceable Terms And Conditions And Thus Fails To Properly Limit PTE.

### 1. The Permit Lacks Design and Operational Limits Needed To Assure Compliance With The Claimed Control Efficiencies.

As discussed above, the 90% assumed control efficiency from the LDAR program for fugitive leaks from the AGR is an unrealistic and unreasonable control efficiency for emissions

[44] *See* RACT/BACT/LAER database, *available at* http://cfpub1.epa.gov/RBLC/.

calculations purposes. It also fails to assure compliance and is unenforceable. Nothing in the Permit itself actually ensures compliance with the 90% assumed control efficiency, emissions calculations, MACT minor source emissions thresholds, or 9 tpy methanol limit. Nor, as discussed below, does the Permit require any monitoring to determine whether these projected control efficiencies and leak rates are being achieved in practice. Rather than requiring a demonstration that these unsupported projections are valid, the Permit instead allows Kentucky Syngas to submit periodic emission evaluations by using *these same leak rates and control efficiencies* in the same fashion they were used in the PTE calculations for determining whether the project exceeded the MACT threshold. In other words, the applicant can demonstrate "compliance" with its methanol emission limit by simply repeating the calculations it used to estimate methanol emissions in the first place. *Compare* emissions calculations at Application C-24 to C-27, at 104-107 (LDAR control efficiencies used to calculate controlled emissions rates, fn 4) *with* Permit at 92-94, Cond. 6, Compliance Demonstration Method (using same LDAR control efficiencies in compliance calculations). Thus, the permit automatically ensures that the estimated fugitive emissions rate will be achieved.

Moreover, as its LDAR plan, the Permit contains a mere ten conditions regarding leak detection and repair. Some of the leak detection is only required to be done on a quarterly basis (Permit at 39, conditions c. and g.); some only on an annual basis (Permit at 40, condition j). The conditions regarding actual leak repair are even weaker. The Permit only requires a "first attempt" to repair damaged or leaking equipment "within 5 days." Permit at 40. There is no requirement that Kentucky Syngas make any further "attempts" if that first attempt, as the term implies, is unsuccessful. The next condition goes on to require "Every reasonable effort shall be made to repair a leaking component within 15 days after the leak is found." Permit at 40. This condition is patently deficient. As EPA has stated repeatedly, a permit condition requiring "reasonable efforts" is subjective and thus unenforceable.[45] In sum, these conditions are thin, subjective, and unenforceable. Without a more complete LDAR plan, the Applicant's claims of 90% control from such a plan are without basis. Kentucky Syngas and KDAQ's use of this unsupported 90% control efficiency has not only led to erroneously low PTE calculations, but

[45] Exhibit 33, Letter from Bharat Mathur, EPA Region 5, to Robert F. Hodanbosi, Ohio EPA, Attachment (Nov. 21, 2001); Exhibit 34, U.S. EPA Region 9, "Title V Permit Review Guidelines: Practical Enforceability," (Sept. 9, 1999).

has also resulted in a permit that fails to assure compliance with its limits. For all these reasons, the Administrator must object.

### 2. The Permit Has Insufficient Monitoring To Ensure Compliance With The Limits On PTE.

Title V permits must include compliance certification, testing, monitoring, reporting and recordkeeping requirements sufficient to assure compliance with the terms and conditions of the permit. 40 C.F.R. § 70.6(c)(1). Further, Title V permits must include periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit. *Id.* § 70.6(a)(3)(i)(B). The D.C. Circuit Court of Appeals has likewise emphasized the need to include adequate monitoring, noting that under Title V "a monitoring requirement insufficient 'to assure compliance' with emission limits has no place in a permit unless and until it is supplemented by more rigorous standards." *Sierra Club v. EPA*, 536 F.3d 673, 674 (D.C. Cir. 2008); *see also id.* at 678 ("Title V requires that '[e]very one' of the permits issued by permitting authorities include adequate monitoring requirements.").

Here, not only does the Permit contain a limit for just one HAP (methanol), but it requires no genuine monitoring of HAP emissions at all. As discussed above, the only compliance method required for the methanol limit consists of performing the same emissions calculations that were used to establish the methanol PTE. The use of this circular compliance method renders the 9 tpy limit totally unenforceable. This very issue was addressed by EPA in its Big Stone Objection. There, EPA stated that the permit failed "to indicate how the permittee must demonstrate that it is maintaining emissions at a level below the major source thresholds in section 112, both on an individual HAP basis (i.e., <10 tons per year individual HAP) and on a total HAP basis (i.e., <25 tons per year total HAP)." Big Stone Objection at 11. Regarding total HAPs, EPA went on to say that the State must revise the permit to include

> A requirement specifying how the permittee must demonstrate compliance with the total HAP limit of 23.8 tons per rolling 12-month period, or, alternatively, the State must include an explanation of why monitoring and reporting of HAP emissions above what is required for acid gas and mercury HAP is not necessary to assure compliance with the limit.

*Id.* EPA elaborated on the need for monitoring: "Where emission measurements are to be required, the required method for measurement and the required frequency of measurement must be specified. . . . As mentioned above, the State must develop periodic monitoring requirements that assure compliance with the permit conditions and explain why the proposed requirements will, in fact, assure compliance." *Id.* Likewise, the Kentucky Syngas Permit must include monitoring of both individual HAPS (especially methanol) at all units with the potential to emit methanol, including the AGR vent, the methanol tank, AGR fugitives and the flare, and monitoring of total HAPs or an explanation of why monitoring and reporting of total HAPs is unnecessary. This is especially critical considering the likelihood that HAP emissions will exceed the major source threshold.

Without such monitoring of total HAPs, and combined with the lack of specific design and operational standards regarding control equipment, the limit of 9 tpy methanol is an unenforceable and impermissible blanket limitation on PTE. Bald conclusory statements that emissions will be held under a certain level and are not backed up by specifics do not constitute "physical or operational" limits on maximum capacity to emit:

> [A] fundamental distinction can be drawn between the federally enforceable limitations which are expressly included in the definition of potential to emit and the limitations which defendant argues must be included. Restrictions on hours of operation or on the amount of material which may be combusted or produced are conditions which are, relatively speaking, much easier to "federally enforce." Compliance with such conditions could be easily verified through the testimony of officers, all manner of internal correspondence, and accounting, purchasing, and production records. *In contrast, compliance with blanket restrictions on actual emissions would be virtually impossible to verify or enforce.*

*Louisiana-Pacific Corp.*, 682 F. Supp. at 1133 (emphasis added). This holding has been incorporated into EPA guidance concerning PTE.[46]

Finally, any claims about emissions of organic HAPs are also completely unenforceable due to lack of monitoring. Just as there is no monitoring of combined HAPs, there is also no monitoring for organic HAPS. Any claim that VOCs might act as a surrogate for organic HAPs is unsupported, because the Permit also fails to require CEMS or CAM for VOCs. As the Permit recognizes, *see* Permit at 30, CEMS are available for VOCs. The Permit presumes that compliance with CO limits ensures compliance with VOCs, yet never establishes a correlation between VOCs and CO to be used to determine compliance. Without a quantified relationship between CO and VOCs, CO cannot be further extended to act as a surrogate for organic HAPs.

[46] *See* Exhibit 25, "EPA PTE Guidance."

VOCs and CO are not adequate surrogates for all organic HAPs. There are three classes of organic HAPs that behave differently during combustion: (1) volatile organic compounds, which are gases, for which the VOC as proposed may be an appropriate surrogate; (2) semi-volatile organic compounds, which may be gases or solids, depending on where in the exhaust gas train they are; and (3) particulate organic compounds, such as polynuclear aromatic compounds and dioxins, which are present in the particulate fraction. The different characteristics of these groups are evident in physical and chemical data for the subject organic HAPs as reported in standard handbooks.[47] A single indicator, either VOC or CO, cannot be used as a monitoring surrogate for these three diverse groups of chemicals, as they are chemically and physically dissimilar.

Several of these compounds are not products of incomplete combustion, like VOCs and CO, but rather are formed via distinct chemical reaction pathways. Polynuclear aromatic hydrocarbons are formed in condensation reactions.[48] Dioxins are formed from the reaction of unburned hydrocarbons and chlorine. Dioxins form in the pollution control equipment at flue gas temperatures of 450 to 650 F. Low chlorine fuels, such as subbituminous coals, would form fewer dioxins than bituminous coals, which contain much higher amounts of chlorine.[49] Consequently, there is no monitoring for organic HAPs overall, let alone during startup/shutdown/malfunction when organic HAPs pose the potential to be higher. As discussed above, such emissions have the potential to push Kentucky Syngas over the major source threshold for HAPs, especially once malfunction-related emissions are properly estimated.

The Permit should be revised to include, among other things, the components of a much more complete LDAR program as an enforceable requirement, and then re-circulated for public review. The Permit should also require the use of gas leak imaging cameras[50] as a complement to the usual Method 21 leak surveys, especially in areas not included in Method 21 surveys, due

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[47] John A. Dean, Lange's Handbook of Chemistry, 13th Ed., McGraw Hill Book Co., 1985; Robert H. Perry and Don W. Green, Perry's Chemical Engineers' Handbook, 7th Ed., 1997; David R. Lide (Ed.), CRC Handbook of Chemistry and Physics, CRC Press, 75th Ed., 1994.

[48] William Bartok and Adel F. Sarofim, Fossil Fuel Combustion: A Source Book, John Wiley & Sons,, 1991; J. Warnatz, U. Maas, and R.W. Dibble, Combustion: Physical and Chemical Fundamentals, Modeling and Simulation, Experiments, Pollutant Formation, 2nd Ed., Springer, 1999; D.J. Hucknall, Chemistry of Hydrocarbon Combustion, Chapman and Hall, 1985.

[49] Exhibit 35, Helsinki University of Technology, Halogens, Dioxins/Furans, Slides.

[50] *See e.g.*, Exhibit 36, www.leaksurveysinc.com.

to, for example, access and safety issue (usually about 20 percent of the total component count). Further, direct measurement of fugitive emissions should be required to demonstrate that the assumed emission factors and control efficiencies are valid at the Kentucky Syngas facility and to address increases in VOC, $H_2S$, and TRS emissions associated with processing pet coke and coal.

The above sections on active flaring emissions and equipment leaks outline numerous ways in which the Applicant and KDAQ underestimated HAP PTE. The Administrator must object and require a full reanalysis of whether the proposed facility will be a major source of HAPs.

## IX. THE APPLICATION, SOB, AND PERMIT FAIL TO ACCURATELY ACCOUNT FOR ALL VOC EMISSIONS.

The Administrator must object because Kentucky Syngas and KDAQ have failed to accurately estimate VOC emissions. The facility claims to be below the significance threshold for VOCs. "To preclude the applicability of 401 KAR 51:017 significant emission increase levels for VOC, source-wide emissions of VOC shall be less than thirty-six (36) tons per twelve (12) month rolling total." Permit at 91. Nonetheless, methanol is a VOC. All the errors that were made regarding minor source status for HAPs were also made for the significance level for VOCs. Therefore, for all the reasons discussed elsewhere related to HAPs, the Applicant and KDAQ also

(1) failed to fully account for all VOC emissions from flaring during malfunction and from fugitives at the AGR due to overestimating control efficiencies;

(2) failed to include enforceable permit limits on VOCs and sufficient monitoring to assure compliance with permit limits;

(3) failed to assure that the facility will stay at or below PTE calculations of VOCs; and

(4) failed to assure that the facility stays below the significance threshold for VOCs.

Consequently, the facility is a major source of VOCs and BACT (as well as full air quality modeling) was required for VOCs.

## X. THE PERMIT'S MONITORING REQUIREMENTS ARE INADEQUATE.

The Permit fails to comply with the Clean Air Act's requirement that Title V permits must include terms and conditions necessary to ensure compliance. *See* 42 U.S.C. § 7661c(a) and (c). This statutory requirement is especially relevant to a permit's monitoring requirements. As explained below, the Permit includes insufficient monitoring requirements for several emission units at the Kentucky Syngas facility. The Administrator must therefore object and direct KDAQ to include adequate monitoring provisions in the Permit.

### A. Title V Requires Monitoring Provisions Sufficient To Ensure Compliance With The Emission Limitations And Standards.

The Clean Air Act states that Title V permits "shall include enforceable emission limitations and standards," and "shall set forth inspection, entry, monitoring, compliance certification, and reporting requirements to assure compliance with the permit terms and conditions." 42 U.S.C. § 7661c(a) and (c); 40 C.F.R. § 70.6(c)(1). For a permit condition to be enforceable, the permit must leave no doubt as to what, exactly, the permittee must do to satisfy that condition. As EPA has explained,

> A permit is enforceable as a practical matter (or practically enforceable) if permit conditions establish a clear legal obligation for the source [and] allow compliance to be verified. Providing the source with clear information goes beyond identifying the applicable requirement. It is also important that permit conditions be unambiguous and do not contain language which may intentionally or unintentionally prevent enforcement.

U.S. EPA Region 9 Title V Permit Review Guidelines (Sept. 9, 1999), at III-46.

With respect to monitoring specifically, Title V permits must include "periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit." 40 C.F.R. § 70.6(a)(3)(i)(B). As noted above, the D.C. Circuit has emphasized the need to include adequate monitoring in Title V permits:

> Title V is a complex statute with a clear objective: it enlists EPA and state and local environmental authorities in a common effort to create a permit program for most stationary sources of air pollution. Fundamental to this scheme is the mandate that "[e]ach permit...shall set forth...monitoring...requirements to assure compliance with the permit terms and conditions." 42 U.S.C. § 7661c(c). *By its terms, this mandate means that a monitoring requirement insufficient 'to assure compliance' with emission limits has no place in a permit unless and until it is supplemented by more rigorous standards.*

*Sierra Club*, 536 F.3d at 674 (emphasis added). *Sierra Club* thus reaffirms the statutory directive that Title V permits must include monitoring requirements that assure compliance with emission limits. The D.C. Circuit also recognized that infrequent monitoring is insufficient to ensure compliance with a short-term emission limit, and concluded that state permitting authorities must include adequate monitoring requirements in their Title V operating permits. *Id.* at 675 (noting, as an example, that annual monitoring would not ensure compliance with a daily emissions limit), 678 ("Title V requires that '[e]very one' of the permits issued by permitting authorities include adequate monitoring requirements.").

The NSR Manual likewise emphasizes the necessity of ensuring that emissions limits are practically enforceable. As the Manual states:

> To be enforceable, the permit must also specify that the controls be equipped with monitors and/or recorders measuring the specific parameters cited in the permit or those which ensure the efficiency of the unit as required in the permit. Only through these monitors could an inspector instantaneously measure whether a control was operating within its permit requirements and thus determine an emissions unit's compliance. It is these types of additional permit conditions that render other permit limitations practically and federally enforceable.

NSR Manual at c.5. The Manual also stresses the need to incorporate "continuous, direct emissions measurements" into a permit's monitoring requirements wherever feasible. *Id.* at H.6. If continuous monitoring is not possible, then periodic direct monitoring should be required. Only where direct measurement is infeasible should surrogate, or indirect, parameter monitoring be employed. The Manual further explains that operational standards should only be used to complement other methods of compliance monitoring. *Id.* at I.3; *see also id.* at H.6 ("Where continuous, quantitative measurements are infeasible, surrogate parameters must be expressed in the permit.").

Here, the Administrator must object to the Permit because it fails to include monitoring, recordkeeping, and other requirements to adequately assure compliance, thereby violating 42 U.S.C. § 7661c(a) and 401 KAR 52:020. As explained below, the Permit fails to require sufficient monitoring of emissions limits, thereby rendering those limits unenforceable as a practical matter.

### B. Cooling Tower and Wet Surface Air Cooler (EP-2, EP-3)

The monitoring requirements for $PM/PM_{10}/PM_{2.5}$ emissions from the cooling tower and wet surface air cooler do not adequately ensure compliance.

The permit application estimated $PM/PM_{10}/PM_{2.5}$ emissions from these units using a formula that relies on three variables: the circulating water flow rate within the cooling tower and air cooler, the total dissolved solids ("TDS") concentration in the water, and the drift rate. Kentucky Syngas estimated that the cooling tower's $PM/PM_{10}/PM_{2.5}$ emissions would be 1.67 lb/hr, while the air cooler's emissions would be 0.75 lb/hr. Application, Appx. C, at 28. The Permit used these estimates in setting the emission limits for these two units. Permit at 43. Because particulate matter emissions are the product of these three variables, all three variables must be adequately monitored to ensure compliance with the emission limits. Here, however, none of them are.

The Permit requires virtually no monitoring of the drift rate, stating that the initial performance test need only be repeated once every sixty-two (62) months. Permit at 43-44. Second, the Permit only requires TDS to be tested on a monthly basis. Finally, the Permit contains no specific monitoring requirement at all for the circulating water flow rate, instead merely directing Kentucky Syngas to maintain records of the monthly average. *Id.* at 44. By requiring monitoring only once a month, once every sixty-two months, or not at all, the Permit's monitoring provisions violate the CAA's directive that Title V permits contain monitoring requirements that ensure compliance with the hourly $PM/PM_{10}/PM_{2.5}$ emission standard. *See Sierra Club*, 536 F.3d at 675 (noting that infrequent monitoring fails to ensure compliance with a short-term emission limit).

Because the cooling tower and wet surface air cooler are subject to a short-term $PM/PM_{10}/PM_{2.5}$ emission limit, the Permit must require sufficient monitoring to ensure that this hourly limit is actually being met. $PM/PM_{10}/PM_{2.5}$ from these emission points must therefore be monitored continuously or, at a minimum, on an hourly basis. Without frequent monitoring, leaks in the cooling system or equipment malfunctions could go unnoticed, leading to $PM/PM_{10}/PM_{2.5}$ exceedances that threaten both public health and the environment. Accordingly, the Permit must contain monitoring provisions that require each of the three variables – circulating water flow rate, TDS, and drift rate – be measured on a continual or hourly basis.

Finally, the recordkeeping provisions for these emission units are deficient. For each of the variables discussed above, Kentucky Syngas must be required to maintain records of continuous or hourly data, rather than merely monthly averages.

### C. Clause SRU and ATS Unit (EU-2)

These emissions units are subject to a series of short-term/hourly emissions limits for CO, $NO_x$, $SO_2$, and $PM/PM_{10}/PM_{2.5}$. Permit at 20. The monitoring requirements for these units are inadequate because they fail to ensure that the limits will be met.

First, the Permit fails to require direct monitoring of several pollutants. With respect to $NO_x$, the Permit only requires an initial performance test and monitoring through the use of a temperature measurement device. Permit at 21, 22. This is inadequate, particularly in light of the substantial $NO_x$ emissions expected from this unit. *See* Application at 3-3 (estimating 172.13 tpy from the ABS tower vent). As the NSR Manual explains, an indirect monitoring method, such as a temperature device, is appropriate only where direct monitoring is infeasible. NSR Manual at H.6, I.3. Because direct, continuous monitoring of $NO_x$ is feasible, and especially given that $NO_x$ emissions from EU-02 will far exceed those for the auxiliary boiler (for which CEMS is required, *see* Permit at 54), the Permit should require $NO_x$ emissions from the ABS tower vent to be monitoring with a CEMS. The agency should similarly require that CO be monitoring directly through a CEMS. *Cf.* Permit at 29 (stating that the CO emission limit for EU-05 can be met through a CEMS operated pursuant to 40 C.F.R. § 60.13 or 40 C.F.R. Part 75).

The Permit's monitoring of particulate matter emissions is also deficient. The ABS tower vent, as the greatest single source of PM emissions at the entire facility, may be particularly susceptible to $PM_{2.5}$ exceedances. But rather than require direct monitoring of these emissions, the Permit merely calls for measurement of fiber-bed filter differential pressure drops. Permit at 22. This is insufficient; surrogate monitoring should only be used when direct emissions monitoring is unavailable. NSR Manual at H.6 (stating that surrogate parameters must be used "[w]here continuous, quantitative measurements are infeasible"). The SOB and RTC are devoid of any explanation as to why direct monitoring is infeasible for PM or any other pollutant emitted by this emission unit. Accordingly, to ensure compliance with the hourly emissions limit for $PM/PM_{10}/PM_{2.5}$, Kentucky Syngas should be required to install and operate a CEMS for PM.

Moreover, because many of these PM emissions will be condensable PM, KDAQ should require periodic monitoring of condensable PM.

Second, the visual emissions monitoring required by the Permit is inadequate. As explained in the Response to Comments, the Permit contains a visual emissions monitoring provision to help ensure that the PM emissions limits are being met. RTC at J-102. But this monitoring provision is impermissibly deficient. Generally, visible emissions at major stationary sources like the Kentucky Syngas facility are monitored with a continuous opacity monitoring system ("COMS"). Where a COMS is not available or feasible, visible emissions can be tracked through regular readings taken according to Method 9. Here, however, the Permit requires neither COMS nor Method 9, and instead allows visible emissions to be tracked through a standardless observation procedure. Rather than requiring the measurement of a specific metric (such as opacity %), the Permit merely requires Kentucky Syngas to record whether the visible emissions appear "normal or abnormal." Permit at 22. No instructions or standards are provided for distinguishing between normal and abnormal emissions. And although the Permit calls for opacity to be measured once abnormal emissions are observed, there is no requirement that Method 9 readings be repeated. Rather than rely on a vague and ambiguous standard (such as "normal" vs. "abnormal"), KDAQ should require that Method 22 be used once a shift to determine if any "abnormal" operation is occurring. In this case, any visible emission via Method 22 observation would be classified as "abnormal." Unlike Method 9, no specialized training is required to monitor for visible emissions using Method 22, because Method 22 uses a black-and-white, visible or not visible, determination threshold. As a result line employees without specialized training could be used to conduct once-per-shift Method 22 assessments.

Third, the permit only requires the performance tests for CO, $NO_x$, $SO_2$, and $PM/PM_{10}/PM_{2.5}$ to be conducted once every sixty-two months. Permit at 21. Such infrequent testing falls far short of the Clean Air Act's admonition that monitoring provisions be designed to assure compliance with the permit's hourly emissions limits. *See Sierra Club*, 536 F.3d at 674. Although performance testing should be required even more frequently, at an absolute minimum these tests should be repeated at least once per year.

### D. Acid Gas Removal Unit (EU-05)

This unit is subject to a series of hourly or other short-term emissions limits for CO, $NO_x$, $SO_2$, $PM/PM_{10}/PM_{2.5}$, $H_2S$, $TRS/H_2S$, VOCs, and methanol. Permit at 26. As explained below, the monitoring requirements for these pollutants fail to ensure compliance with the emissions limits.

First, the Permit contains no direct monitoring requirement for $NO_x$ emissions. Other than an infrequent emissions test, *id.* at 27, the permit does not require this pollutant to be monitored at all. This emissions unit should be equipped with a CEMS for $NO_x$ emissions. But even if continuous monitoring is not mandated, at a minimum the Permit must require hourly monitoring of $NO_x$ emissions. *See Sierra Club*, 536 F.3d at 674; 42 U.S.C. § 7661c(a) and (c); 40 C.F.R. §§ 70.6(c)(1); 40 C.F.R. § 70.6(a)(3)(i)(B).

Second, the $SO_2$ monitoring provisions are deficient. Other than an initial emissions test, the Permit requires no direct monitoring of $SO_2$ emissions. And as the NSR Manual explains, indirect monitoring methods are appropriate only where direct monitoring is infeasible. NSR Manual at H.6, I.3. To adequately ensure compliance with this emissions limit, direct monitoring of $SO_2$ is required. More specifically, the $SO_2$ monitoring provisions for the ABS tower vent, *see* Permit at 21-22, should likewise be required for the AGR unit. And even if continuous monitoring is not required, the Permit must, at a minimum, require hourly monitoring of $SO_2$ to ensure that the hourly emissions limit is not exceeded.

The indirect monitoring procedures for $SO_2$ must also be strengthened. Rather than establish a monitoring regime that would ensure adherence to the hourly $SO_2$ limit, the permit instead merely calls for a monthly, or even quarterly, "sulfur content grab sample." Permit at 27, 31. Again, monitoring at such infrequent intervals provides no reasonable assurance that the hourly emissions standard is being met. Continuous or hourly monitoring should be required. Equally troubling, the sulfur content sampling set forth in condition 4(f) is contingent upon an "AGR vent sampling plan" that has not yet been drafted. Permit at 31. Nor does the permit explain the necessary contents and requirements of this plan – indeed, this plan is not mentioned anywhere else in the permit. Compliance with emission limits cannot be based on a to-be-determined sampling plan with no clear standards. As explained above at part III.B, rather than rely on a to-be-determined sampling plan with no clear standards, KDAQ must spell out the requirements for sulfur content sampling in the permit itself, and subject those provisions to public comment. KDAQ's failure to do so violates the Clean Air Act. *See RockGen Energy Center*, 8 E.A.D. at 552-55.

Third, the permit contains no monitoring requirements for particulate matter. The only PM-related monitoring of any kind required by the permit is an initial test of opacity. Permit at 27. KDAQ must establish monitoring of PM emissions on a continuous or hourly basis to ensure that this short-term emissions limit is met. Ongoing monitoring of opacity must be also required. If a continuous opacity monitor is not installed, the agency should require that, at a minimum, Method 9 opacity readings be taken at periodic intervals.

Fourth, the monitoring requirements for CO, $H_2S$, and VOC are inadequate. For these pollutants, the permit allows Kentucky Syngas to choose between the use of a CEMS or conducting a performance test every thirty-two months (as opposed to every sixty-two months if CEMS are installed). Permit at 29-30. But given that CEMS are clearly feasible for these pollutants, KDAQ must mandate that CEMS be used, because direct continuous emissions monitoring should be employed whenever possible. NSR Manual at H.6; *see also id.* at I.3 ("Continuous, direct emission measurement is preferable.").[51]

Finally, the Permit's monitoring provisions were weakened between the draft and final permits, when KDAQ, at Kentucky Syngas's request, removed the $H_2S$ CEMS monitoring requirement and replaced it with an $SO_2$ monitoring requirement. RTC at J-104. The direct monitoring of $H_2S$, a highly toxic compound, should be required by the Permit.

### E. Auxiliary Boiler (EU-08)

This emissions unit is subject to a series of hourly or other short-term emissions limits for CO, $NO_x$, $SO_2$, $PM/PM_{10}/PM_{2.5}$, and opacity. Permit at 52-53. But here again, the monitoring requirements fail to ensure compliance with those limits.

First, other than an initial performance test (which must only be repeated every sixty-two months), there are no monitoring requirements for CO. *See* Permit at 54. Such sporadic testing

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[51] The use of performance tests on a 32-month rotation hardly satisfies the Clean Air Act's directive that periodic monitoring be required, and that such monitoring be conducted so as to assure compliance with emissions limits. 40 C.F.R. §§ 70.6(c)(1); 40 C.F.R. § 70.6(a)(3)(i)(B). As the Administrator recognized in another Title V permitting matter, although "stack tests are an important part of periodic monitoring," it is also important that permits "specify monitoring to assure compliance in between stack tests." *In re NYCDEP North River Water Pollution Control Plant*, Petition No. II-2002-11, 2004 EPA CAA Title V LEXIS 11 at *90 (EPA Adm'r Sept. 24, 2004).

fails to provide any assurance that the hourly CO limits are being adhered to. KDAQ must not only require some actual monitoring of this pollutant, but that monitoring must also be frequent enough to ensure that short-term exceedances are not occurring. Just as the agency requires CEMS for $NO_x$, so too should the agency mandate CEMS for CO. The appropriateness of CEMS for CO emissions is all the more compelling given that the projected CO emissions from this auxiliary boiler are anticipated to be nearly twice as great as those for $NO_x$. *See* Application at 3-3. And if CEMS is not imposed, then monitoring on an hourly basis must be required.

Second, because the monitoring for $PM/PM_{10}/PM_{2.5}$ is equally deficient – the Permit only requires a performance test every sixty-two months – KDAQ should mandate CEMS for these emissions. And even if continuous monitoring is not required, then KDAQ must impose some other type of short-term monitoring to ensure that the hourly limits for $PM/PM_{10}/PM_{2.5}$ are not being exceeded.

Third, periodic monitoring is also required for $SO_2$. Even if Kentucky Syngas only uses low-sulfur gaseous fuel, *see* Permit at 54, some type of actual emissions monitoring is necessary. So if a CEMS is not installed for $SO_2$, KDAQ must mandate some short-term monitoring to ensure that $SO_2$ emissions limits are being followed.

Fourth, although the Permit establishes an opacity limit for the auxiliary boiler, *see* Permit at 53, the permit contains no opacity monitoring requirements at all. Even if KDAQ anticipates that the opacity of emissions will remain low due to the type of fuel being burned, *see id.* at 54, some genuine monitoring is necessary to assure compliance with this permit requirement. 42 U.S.C. § 7661c(c).

## XI. KENTUCKY SYNGAS AND KDAQ FAILED TO ACCURATELY ESTIMATE, SUFFICIENTLY CONTROL, AND ADEQUATELY MODEL PM.

The Administrator must object because Kentucky Syngas and KDAQ failed to ensure that the proposed facility will not violate the $PM_{10}$ and $PM_{2.5}$ NAAQS, due to their failure to properly estimate PM emissions allowed under the Permit.[52] These emissions underestimates are detailed below. Among the "applicable requirements" with which a Title V permit must ensure compliance are 42 U.S.C. § 7475(a)(3), 401 KAR 51:017, sections 8, 10, & 11 (SIP-approved version), 401 KAR 52:020, sec. 1(3) & 21, 401 KAR 53:005, sec. 1(3), and the NAAQS. These

[52] KDAQ is required to ensure protection of the $PM_{2.5}$ NAAQS independently from the $PM_{10}$ NAAQS.

provisions prohibit emissions that would cause and/or contribute to a violation of ambient air quality standards and PSD increments. Here, numerous calculation and methodological errors caused the Applicant and KDAQ to significantly underestimate $PM_{10}$ and $PM_{2.5}$ emissions from the facility. These underestimates are not only unlawful in their own right, but they also raise the strong possibility that the Kentucky Syngas facility will exceed the NAAQS and/or PSD increment for particulate matter. The Applicant and KDAQ must go back and correct the emission estimates, gather the legally mandated preconstruction monitoring data, conduct full NAAQS and PSD increment modeling using the corrected emissions figures, and subject the revised modeling demonstration to public comment.

## A. KDAQ And Kentucky Syngas Underestimated PM Emissions From The Facility.

The potential to emit $PM_{10}$ and $PM_{2.5}$ emissions from the facility has been underestimated in multiple respects. As described below, underestimated sources of $PM_{10}$ and $PM_{2.5}$ include unpaved roads, paved roads, storage piles, and the cooling tower and wet surface air cooler.

**Cooling Tower and Wet Surface Air Cooler.** Particulate matter emissions from the cooling tower and wet surface air cooler are underestimated. In its permit application, Kentucky Syngas estimated that the $PM_{10}$ emissions rate from the cooling tower (EU03) and wet surface air cooler (EU04) would be 1.67 lb/hr and 0.75 lb/hr, respectively. Application, Appx. C, at 28; *see also* Permit at 43 (limiting emissions to same amount). These emissions were calculated using a procedure that substantially underestimates cooling tower emissions. These emissions were also used in the Applicant's air quality impact analyses, which therefore underestimate modeled ambient $PM_{10}$ concentrations.

Cooling tower $PM_{10}$ emissions are normally calculated using EPA's AP-42. The EPA procedure involves multiplying the drift rate by the salt content of the circulating water. The EPA procedure assumes that the water evaporates, leaving behind finely dispersed salts with particle sizes less than 10 microns, i.e., $PM_{10}$.[53] As discussed below, this EPA procedure has been validated using cascade impactor tests at operating cooling towers.

[53] Exhibit 37, United States EPA, Office of Air Quality Planning and Standards, AP-42, Section 13.4, Wet Cooling Towers, January 1995, at 13.4-2.

Although asserting that its calculations were "based on the methodology presented in AP-42," Application at 3-10, Kentucky Syngas in fact eschewed that methodology in generating $PM_{10}$ emissions estimates for the cooling tower and wet surface air cooler. Instead, the Applicant used an independent paper (based on a single, 22-year-old data set) to argue that only 30% of the particles emitted by the cooling tower, and only 5% of the particles emitted by the air cooler, are $PM_{10}$.[54] In doing so, the Applicant generated emissions estimates that were significantly lower than those predicted by the EPA methodology. If the EPA procedure were used, $PM_{10}$ emissions from the cooling tower would increase from 1.67 lb/hr to 5.57 lb/hr, and $PM_{10}$ emissions from the air cooler would increase from 0.75 lb/hr to 15.0 lb/hr.[55] EPA has a long history of using this AP-42 procedure and not the procedure advocated by Kentucky Syngas.

EPA's method is also verified by studies. Actual measurements using cascade impactors show that cooling tower drift is 100% $PM_{10}$.[56] In one study, the researchers concluded: "There is sufficient information from the first set of cascade impactor tests to support the conclusion that the drift emitted from the cooling towers consists of water droplets that are so small that when they dry, the remaining solid particulates are all $PM_{10}$."[57] The large water droplets that Kentucky Syngas relied on are not emitted from the tower. Only the smaller droplets are actually emitted and thus qualify as "drift."

Although AP-42 should be used for both $PM_{10}$ calculations, Kentucky Syngas's use of an alternative procedure is particularly inappropriate for the wet surface air cooler. For one thing, the paper cited by the Applicant only discusses cooling towers, not air coolers. For another, the paper only considers cooling towers with total dissolved solid ("TDS") concentrations between 1000 and 12,000 parts per million by weight (ppmw). Application, Appx. C-6. The air cooler for the Kentucky Syngas facility, by contrast, has a potential TDS value of 300,000 ppm. Given

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[54] *See* Application, Appx. C-6 (citing Joel Reisman and Gordon Frisbie, *Calculating Realistic $PM_{10}$ Emissions from Cooling Towers*, 31 Envt'l Progress 127 (2002) (published online Apr. 20, 2004)).

[55] Cooling tower: 1.67 lb/hr * 1/0.3 = 5.57 lb/hr; Wet surface air cooler: 0.75 lb/hr * 1/0.05 = 15.0 lb/hr.

[56] *See* Exhibit 38, G. Israelson, N. Stich, and T. Weast, *Comparison of Cooling Tower Mineral Mass Emissions by Isokinetic EPA Method 13A and Heated Cascade Impactor Tests*, Cooling Tower Institute Paper No. TP91-12, 1991; Exhibit 39, Thomas E. Weast and Nicholas M. Stich, *Reduction of Cooling Tower $PM_{10}$ Emissions Due to Drift Eliminator Modifications at a Chemical Refining Plant*, Cooling Tower Institute Paper No TP92-10, 1992.

[57] Exhibit 39, Weast & Stich, *supra*, at 4.

that the TDS values in the air cooler will be 25 times greater than the maximum values discussed in the paper, this paper cannot be used to support Kentucky Syngas's unreasonably low emissions estimates.

Kentucky Syngas's reliance on a methodology that produces emissions estimates substantially below AP-42 estimates is even more inappropriate given the uncertainties associated with AP-42. As EPA has repeatedly recognized, "AP-42 factors do not necessarily yield accurate emissions estimates for individual sources," and "use of these factors to develop source-specific permit limits . . . is generally not recommended." *In the Matter of Tesoro Refining and Marketing Co., Martinez, California Facility, Major Facility Review Permit*, Petition No. IX-2004-6, 2005 EPA CAA Title V LEXIS 9, at *81-82 (EPA Adm'r Mar. 15, 2005). In *Tesoro*, the Administrator found that notwithstanding the potential variability of emissions, use of the AP-42 emission factor for $PM_{10}$ from cooling towers was appropriate because the estimate is conservative, and therefore "represent[s] a reasonable upper bound of the emissions." *Id.* at 87 n.18, 89. In other words, due to the uncertainties associated with AP-42 itself, it is appropriate to use this conservative methodology. Kentucky Syngas's use of an alternative procedure, which results in estimated emissions that are 5-30% of the AP-42 estimates, is inappropriate.

For these reasons, the procedure used by the Applicant to calculate $PM_{10}$ emissions from the cooling tower and wet surface air cooler is not consistent with EPA's standard methodology and substantially underestimates $PM_{10}$ emissions. These emissions estimates should be revised according to EPA's standard approach.

Kentucky Syngas's reliance on the Reisman/Frisbie paper in calculating the proportion of drift that is $PM_{10}$ is erroneous for the additional reason that it used water not reflective of actual conditions. The Reisman/Frisbie paper analyzed a drift eliminator with a guaranteed efficiency of 0.0006%. BACT is now 0.0005%, which means the particle size distribution will be smaller with a BACT-level drift eliminator. The example cited in the Reisman/Frisbie paper has a TDS content in the emitted droplets of 7700 ppm. The typical "cycles of concentration" between TDS raw makeup water and the TDS in the cooling tower drift is in the range of 4-to-1. This means that the Reisman/Frisbie example is based on a source with an equivalent raw makeup water TDS concentration of about 2,000 ppm. This is brackish water. By contrast, fresh water in rural Kentucky tends to have a low TDS concentration. For example, typical Ohio River water would have a TDS in the range of 100 to 300 ppm, one-tenth the TDS level represented in the Reisman/Frisbie example.[58] Both the higher efficiency of a BACT-level drift eliminator and the much lower TDS in the drift droplets mean the percentage of $PM_{10}$ determined in the Reisman/Frisbie example is irrelevant to the cooling tower at Kentucky Syngas.

**Unpaved Roads.** $PM_{10}$ and $PM_{2.5}$ emissions from unpaved roads are underestimated because, among other things, the Permit conditions do not support the assumed control efficiency of 90%. For unpaved haul roads (EU34 and EU35), the only operating *or* emissions limitation in the permit is the use of water sprays. Permit at 85. And the 90% assumed dust control efficiency is almost certainly unachievable, even if Kentucky Syngas continuously applies water to the unpaved haul roads. Moreover, the practice of continuous watering is impractical or impossible (especially during winter when watering is prevented by ice formation). In any event, continuous watering is not required by the Permit, which only includes a generic directive that Kentucky Syngas do water spraying "whenever the material storage and haul road emissions are in operation." Permit at 85. Nowhere does the Permit specify the frequency with which watering must be done, or any details about this supposed operating limit. Similarly, the permit application merely states, without elaboration, that "[w]atering will be conducted as necessary to achieve adequate control." Application at 10-24. Because the permit's "water spraying" control is not enforceable as a practical matter, the claimed 90% control cannot represent the worst-case conditions that must be assumed for purposes of PSD air quality modeling.

Even if the Permit did prescribe frequent watering of unpaved roads, the assumed control efficiency would still be unrealistic. Dust emissions from unpaved roads, as well as possible control approaches, have been widely studied. Using watering as a control technique will typically yield unpaved road dust control efficiencies on the order of 50%. Following are several references documenting this finding:

- EPA reports 50% control for a water application intensity of about 0.2 gallon/yd$^2$/hour. Exhibit 41, EPA, Control of Open Fugitive Dust Sources, EPA-450/3-88-008, September 1988, at 5-10.
- Exhibit 42, Howard Hesketh and Frank Cross, Fugitive Emissions and Controls, Ann Arbor Science, 1983, at 42 (50% control efficiency) (excerpt).

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[58] *See* Exhibit 40, Kirby Scott, Total Dissolved Solids, Test 12, *Water Quality with Computers*, INTDS Paper at 3, *available at* http://www.clc.mnscu.edu/kscott/chem1425/wqlabs/Test12TotalDissolvedSolid.pdf.

- The South Coast Air Quality Management District suggests control efficiencies of 34 to 68% for watering of unpaved roads. *See* Exhibit 43, South Coast Air Quality Management District, CEQA Air Quality Handbook, April 1993, at 11-15 (excerpt).
- The WRAP Fugitive Dust Handbook cites a control efficiency of 55% for watering of unpaved roads. *See* Exhibit 44, Western Governors' Association, WRAP Fugitive Dust handbook, at 6-15 (Nov. 15, 2004).

Based on these sources, any assumed control efficiency greater than 75% (which is most likely an overestimation of achievable fugitive dust control) must be rejected.

**Paved Roads.** $PM_{10}$ and $PM_{2.5}$ emissions from paved roads are underestimated because Kentucky Syngas and KDAQ used an inappropriately low silt loading factor of 0.6 $g/m^2$. This value fails to reflect the worst-case silt conditions allowed under the permit for purposes of estimating PM emissions from paved roads and modeling the impact of these emissions.

The AP-42 section for paved roads, Section 13.2.1, specifically states that the use of a tabulated default value for silt loading results in only an order-of-magnitude estimate of the emission factor for fugitive dust from truck traffic on paved roads and, therefore, highly recommends the collection and use of site-specific silt loading data. There is no evidence in the record that either Kentucky Syngas or KDAQ attempted to ascertain silt loading data from a similar existing source. Instead, without citing any hard evidence, they relied on the applicant's unsupported "engineering judgment" in using this value. Application, Appx. C, at 61. This approach is insufficient. As EPA's Preliminary Emissions Factors Program Improvement Option Paper 4 states, "[a]ll emissions estimates must be from similar sources equipped with similar control equipment and operating at similar process/control equipment parameter rates."[59] There is no evidence in the record that the statements regarding road usage equating to 0.6 $g/m^2$ are based on other similar sources.

Where a source cannot obtain site-specific data (assuming for argument's sake that Kentucky Syngas or KDAQ had made an effort to do so but had failed), AP-42 recommends the selection of an appropriate mean value from a table listing silt loadings that were experimentally determined for a variety of industrial roads. KDAQ erred in several ways in selecting its value from the AP-42 industrial paved road table:

[59] Exhibit 45, EPA, Appendix D Preliminary Emissions Factors Program Improvement Option Paper 4 Providing Guidance Regarding the Use of Emissions Factors for Purposes Other than Emissions Inventories, at 4-4, Table 4.1 ("Option Paper 4").

- the AP-42 values represent average values. In permitting, a source is required to estimate the maximum Potential to Emit from the specific source, and to model worst case emissions to ensure protection of the NAAQS. Given these requirements, the use of average values for material handling purposes here is inappropriate. EPA has voiced this caution with regards to applicability, stating that "AP-42 emissions factors represent an average range of emissions rates for a source category and are not precise enough for regulatory applicability determination."[60] KDAQ did not adjust for this factor.

- EPA also cautions that use of the table values for silt instead of site-specific values decreases the quality rating of the paved road equation by 2 levels.[61] KDAQ failed entirely to account for the reduction in quality rating of the equation due to use of the non-facility specific values.

- EPA's Option Paper 4 also recommends allowing only factors of a minimum rating of "B" for permitting purposes, and furthermore recommends using the maximum of the range of reported values in this context.[62] Rather than heed this guidance, KDAQ selected a silt value, 0.6 $g/m^2$, that is at the very low end of the reported range for the industry chosen from the industrial paved road silt table (0.09 to 79 $g/m^2$). Nowhere does KDAQ explain why the silt at the facility is more consistent with the low end of this range instead of the average or the high end. The industrial roadway table provides a range of mean silt loading values from 7.4 to 292 $g/m^2$.[63] At the very least, given the requirement to estimate PTE and model worst case emission, KDAQ should have chosen a value representing the mean for the industry chosen, or 7.4 $g/m^2$.

- In selecting the 0.6$g/m^2$ silt loading factor, Kentucky Syngas and KDAQ fail to explain why such a low factor was chosen. The facility will handle significant amounts of coal and petroleum coke. This handling of a dry substance has the potential to impact the silt values on the paved roads, even where the paved roads themselves are limited to transport of slag, sulfur, and methanol, due to carryover from other operations (such as by wind). The choice of a very low value does not account for this additional factor impacting silt at the Kentucky Syngas facility.

- The Permit fails to contain terms and conditions that limit the silt on the paved roads on a continuous basis to the 0.6 $g/m^2$ assumed in the calculations. The only specific control measure for paved roads listed in the Permit is "periodic sweeping." Permit at 84, 85. Nowhere does the Permit specify the frequency with which sweeping must be done, or any details about this supposed operating limit. Similarly, the Application merely states, without elaboration, that sweeping will be conducted "as necessary based on visual observations." Application at 10-24. Because the Permit's "periodic sweeping" control is not enforceable as a practical matter, the silt loading value cannot represent the worst-case conditions that must be assumed for purposes of PTE and PSD air quality modeling.

[60] Option Paper 4 at 4-3, Table 4.1.

[61] Exhibit 46, AP-42 Paved Roads, at 13.2.1.-6.

[62] *See* Exhibit 45, EPA EF Option Paper 4, at 4-11, Table 4.4, "Future Uses of Emissions Factors."

[63] Exhibit 46, AP-42 Paved Roads, at Table 13.2.1-4.

**Material Storage Piles.** $PM_{10}$ and $PM_{2.5}$ emissions from storage piles (EU28-32) are also underestimated. First, for the disposal storage piles (PIL 08, 09, 10), the 90% assumed control efficiency is inappropriate for the same reason as for unpaved haul roads. *See supra.* Likewise, the 75% assumed control efficiency for the coal, coke, and temporary slag piles (PIL 01-07), *see* Application, Appx. C, at 58, is also unrealistic. A more realistic storage pile fugitive $PM_{10}$ emission control efficiency is on the order of 60%. This level has been documented by EPA, which found that inhalable particles are reduced from 50 to 70% by chemical suppressants applied to coal storage piles (the control efficiency is reduced to 50% only four days after chemical suppressant is applied).[64]

In addition, the control measure listed – "dust suppression" – is unenforceably vague and therefore does not constitute a proper limitation on potential to emit from material storage piles sources sufficient to assume the unreasonably high control efficiencies. Particular sources of vagueness include, but are not limited to, failures to:

- specify the provisions of the "fugitive coal dust emissions control plan," Permit at 86-87;
- specify the circumstances in which a specific dust suppression method, such as "asphalt, oil, water, or suitable chemicals," must be used under operating limitation (b)(2), *id.* at 85;
- specify the frequency with which one of these suppression methods must be applied under operating limitation (b)(2), *id.*, or when wet suppression is "necessary," *id.* at 86;
- indicate when the permittee should use chemical suppression alone, wet suppression alone, or chemical suppression in combination with wet suppression under operating limitation (b)(1), *id.* at 85;
- specify the atmospheric and operational conditions under which one of the suppression methods must be applied under operating limitation (b)(2), *id.*;
- describe in enforceable terms how to determine when a measure is "applicable" in operating limitation (b), *id.*;
- describe in enforceable terms how a chemical is deemed "suitable" pursuant to operating limitation (b)(2), *id.*; and
- describe in enforceable terms what "other surfaces" are encompassed by that term in operating limitation (b)(2), *id.*

The emissions underestimates set forth above render the Permit unlawful. By neglecting to properly estimate $PM_{10}$ and $PM_{2.5}$ emissions, Kentucky Syngas failed to demonstrate its

[64] EPA Fugitive Dust Control at 4-22.

compliance with statutory requirements and therefore violated the law. In order to obtain a PSD permit, a facility owner must show "that emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of any (A) maximum allowable increase or maximum allowable concentration for any pollutant in any area to which this part applies more than one time per year, (B) national ambient air quality standard in any air quality control region, or (C) any other applicable emission standard or standard of performance under this chapter." 42 U.S.C. § 7475(a)(3); 401 KAR 51:017, section 23 (setting PSD increments for $PM_{10}$) (SIP-approved version); 401 KAR 53:010, section 2 & Appx. A (setting 24-hour $PM_{10}$ standard and requiring $PM_{10}$ measurement); 40 C.F.R. §§ 50.6, 50.7 (NAAQS for $PM_{10}$ and $PM_{2.5}$). These standards protect the health and welfare of Kentucky citizens by specifying the maximum amount of pollutant a source may produce in any given 24-hour period. State and federal ambient air quality standards specify the maximum allowable amount of pollution in outdoor air. In order to receive a PSD permit, an applicant must demonstrate compliance with both ambient air quality standards and PSD increments.

Because Kentucky Syngas failed to include all of the facility's PM emissions in its 24-hour emissions modeling, the Applicant has not demonstrated compliance with either of these standards, and the Permit was improperly issued. As noted above, a source's impact analysis must be based on "maximum," or "worst-case" emissions. Indeed, the EAB recently remanded a PSD permit for failure to account for worst-case emissions in the air quality modeling. *Northern Michigan University,* PSD Appeal 08-02, slip op. at 49 (citing NSR Manual). For both NAAQS and PSD increment compliance demonstrations, the emissions rate for the proposed new source must reflect the maximum allowable operating conditions as expressed by the federally enforceable emissions limit, operating level, and operating factor for each applicable pollutant and averaging time. The applicant should base the emissions rates on the results of the BACT analysis. *Id.*

Kentucky Syngas's impact analysis does not account for the worst-case emissions because it omits a significant source of pollutants, namely, PM emissions from the cooling tower, wet surface air cooler, haul roads, and storage piles. This is sufficient grounds for objecting to and remanding a permit. In *Masonite,* for example, the EAB remanded a PSD permit that EPA issued to a paneling and siding manufacturer, *inter alia,* because the agency had failed to count fugitive particulate matter emissions from wood-chip handling in determining the net emissions increase of a major facility modification. *In Re Masonite Corporation*, 5 E.A.D. 551 (EAB 1994). Here too, PM emissions have been improperly underestimated.

By omitting various PM emissions, Kentucky Syngas has failed to demonstrate compliance with ambient air quality standards and the PSD increment. Kentucky Syngas cannot make the legally required demonstration by ignoring these substantial sources of PM emissions. In order to construct a new major source of air pollution, applicants must demonstrate the proposed project would not contribute to significant air quality deterioration. 42 U.S.C. § 7475(a)(3). By neglecting to properly estimate and model impacts from its PM emissions, Kentucky Syngas did not comply with the legal requirements for a PSD permit application, and KDAQ improperly issued the Permit. The Administrator must therefore object to the Permit.

### B. The Permit Contains Unenforceably Vague Conditions for Material Handling.

The Administrator should also object because the material handling measures listed in the Permit are unenforceably vague and therefore do not constitute proper limitations on potential to emit from material handling sources, such as coal and slag storage piles. To be enforceable, a permit must create mandatory obligations that provide a clear explanation of how the actual limitation or requirement applies to the facility and make it possible for KDAQ, EPA, and citizens to determine whether the facility is complying with the condition. EPA has made clear that vague and ambiguous permit language is not enforceable:

> Many Title V permits contain ambiguous phrases, such as "if necessary." For example: "If necessary, the permittee shall maintain monthly records…." The phrase "if necessary" should be removed altogether; the permit should specify exactly what is necessary. In this example, the permit should either precisely explain the situation that would necessitate monthly records, or simply require monthly records at all times. Ambiguous language hampers the source in its duty to independently assure compliance, and leaves legal requirements open to interpretation.[65]

Here, however, the Permit's material handling provisions are impermissibly vague. *See supra* at part XI.A (listing sources of vagueness, citing Permit at 85-87). Because the Permit terms and

[65] Exhibit 33, Letter from Bharat Mathur, EPA Region 5, to Robert F. Hodanbosi, Ohio EPA, November 21, 2001.

conditions are not enforceable, and do not ensure the exceptionally high control efficiencies assumed in the PM emission estimates, the Administrator must object.

## XII. KDAQ FAILED TO DEMONSTRATE THAT THE PROPOSED FACILITY WILL NOT CAUSE OR CONTRIBUTE TO VIOLATIONS OF THE OZONE NAAQS.

The Administrator must object because the Applicant and KDAQ have failed to show that the proposed source will not cause or contribute to violations of ozone air quality standards. Even under KDAQ's incomplete assessment of emissions, the proposed Kentucky Syngas facility will emit large amounts of $NO_x$ (254.35 tpy) and VOC (20.92 tpy). These ozone precursors react under sunlight to form ozone, a harmful pollutant that attacks the respiratory system. The inappropriate qualitative assessment of ozone impacts relied on by KDAQ is insufficient to ensure protection of the ozone NAAQS. Based on regulatory requirements and due to serious concerns about ozone levels in nearby areas, the Applicant must conduct individual source modeling of ozone impacts. It must then submit these analyses to KDAQ for the agency's and public's assessment.

### A. The Applicant Failed to Conduct, and KDAQ Failed to Require, Actual Ozone Modeling.

The ozone analysis is insufficient because it relies on a dated, unapproved, non-site-specific qualitative method instead of the required source-specific modeling. In order to assess impacts to air quality, the Clean Air Act requires applicants and agencies to use modeling. *See* 42 U.S.C. § 7475(e)(3)(D) (requiring the Administrator to promulgate regulations specifying "each air quality model or models *to be used* for purposes" (emphasis added) of the PSD program, specifically the ambient air quality demonstration); *see also* 40 C.F.R. § 51.166(m).[66] Kentucky regulations echo this requirement. *See* 401 KAR 51:017 Section 10 ("Air Quality Models. (1) Estimates of ambient concentrations *shall be based on the applicable air quality*

[66] *See also* Exhibit 16, NSR Manual at C.24 ("Dispersion models are the primary tools used in the air quality analysis. These models estimate the ambient concentrations that will result from the PSD applicant's proposed emissions in combination with emissions from existing sources. The estimated total concentrations are used to demonstrate compliance with any applicable NAAQS or PSD increments. The applicant should consult with the permitting agency to determine the particular requirements for the modeling analysis to assure acceptability of any air quality modeling technique(s) used to perform the air quality analysis contained in the PSD application.").

*models*, data bases, and other requirements specified in 40 C.F.R. Part 51, Appendix W, 'Guideline on Air Quality Models' (2003), Appendix A."). Modeling must be conducted for each pollutant that the proposed source would emit in significant amounts. 401 KAR 51:017 Section 11(1)(a)1. EPA regulations describe the importance and baseline requirements of modeling as follows:

- [T]he impacts of new sources that do not yet exist can only be determined through modeling.

- In all cases, the model applied to a given situation should be the one that provides the most accurate representation of atmospheric transport, dispersion, and chemical transformations in the area of interest.

- To ensure consistency, deviations from this guide should be carefully documented and fully supported, [and] consistency is not [to be] promoted at the expense of model and data base accuracy.

40 C.F.R. Part 51 Appendix W Subsections 1.b to 1.e. States and applicants are not to undertake their own independent adjustments of modeling approaches, but must seek federal approval of deviations from federal regulatory guidelines. 42 U.S.C. § 7475(e).[67] In sum, modeling (a) is imperative for new sources, (b) must be accurate, up-to-date, and site-specific to the greatest degree possible, and (c) must fully justify any deviations from the federal guidance and receive federal approval of any alternative modeling approach.

Here, neither the Applicant nor KDAQ conducted any source-specific individual source modeling to demonstrate compliance with ozone ambient air quality standards.[68] The Applicant

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[67] "Any model or models designated under such regulations may be adjusted upon a determination, after notice and opportunity for public hearing, by the Administrator that such adjustment is necessary to take into account unique terrain or meteorological characteristics of an area potentially affected by emissions from a source applying for a permit required under this part." *See also* 401 KAR 51:017 Section 10: "(2) If an air quality model specified in 40 C.F.R. Part 51, Appendix W, is inappropriate, the model may be modified or another model substituted. (a) The use of a modified or substitute model shall be:

1. Subject to notice and opportunity for public comment under 401 KAR 52:100; and

2. Made on a *case-by-case basis* and *receive written approval from the U.S. EPA*." (emphasis added); Appendix W at 3.2.2 (giving Regional Offices responsibility for determining the acceptability of alternative models, and proscribing specific criteria for approval by the Regional Administrator).

[68] *See* SOB at 143 ("The ozone ambient impact analysis provided by Kentucky Syngas is qualitative in nature. Estimates of increases in ozone formation were determined by scaling $NO_x$ emissions from the facility using data from modeling sensitivity studies conducted by Georgia Environmental Protection Department (EPD) in support of their 8-hr ozone SIP development.") and Exhibit 47, Letter from Trinity

cites Subsection 5.2.1c, entitled "Estimating the Impact of Individual Sources," as support for its use of a "qualitative" analysis using unmodified 3-year-old regional modeling from another state:

> *Choice of methods used to assess the impact of an individual source depends on the nature of the source and its emissions. Thus, model users should consult with the Regional Office to determine the most suitable approach on a case-by-case basis (subsection 3.2.2).*[69]

This citation is misleading and does not provide support for the approach taken by the Applicant and KDAQ. Nowhere does Subsection 5.2.1c exempt a source from the requirement to conduct modeling for ozone; instead, the quoted passage must be read in context to mean that a case-by-case approach should be taken for *individual source modeling methods* for ozone impacts, following the process outlined in Subsection 3.2.2. *See* Appendix W at 5.2.1 (entitled "Models for Ozone" and citing Section 3.2.2). A qualitative adaptation of modeling done years ago by another state for different purposes is not alternative modeling for an individual source.

Nor is there any evidence in the record that the Applicant and KDAQ received the required regional approval for their approach. As noted above, such approval would include a case-by-case analysis of the appropriateness of the approach, following a process prescribed by EPA regulations. *See* Appendix W at Subsection 3.2.2.[70] The only mention of Region IV approval in the record is a reference in Appendix A to a letter to the Georgia EPD dated December 2000,[71] which states:

> *Although ozone impact modeling is not normally required for single sources, information on the current ozone levels in the area should be cited to provide qualitative assurance that the increased [emissions] from facility operation will not cause or contribute to violations of the ozone national ambient air quality*

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Consultants to KDAQ, at 2 (Sept. 4, 2009) (noting that "Kentucky Syngas is providing the following qualitative ozone impacts analysis for the Kentucky NewGas site").

[69] Exhibit 47, Letter from Trinity Consultants to KDAQ, at 2 (Sept. 4, 2009).

[70] Notably, the lack of an approved model does not mean that the applicant's preferred modeling approach gets the green light. Rather, an alternative model may be used only if: "i. The model has received a scientific peer review; ii. The model can be demonstrated to be applicable to the problem on a theoretical basis; iii. The data bases which are necessary to perform the analysis are available and adequate; iv. Appropriate performance evaluations of the model have shown that the model is not biased toward underestimates; and v. A protocol on methods and procedures to be followed has been established." Appendix W Subsection 3.2.2(e). The record does not demonstrate that these criteria have been met.

[71] Exhibit 47, Letter from Trinity Consultants to KDAQ, at 2 (Sept. 4, 2009) (citing "Letter dated December 13, 2000, from EPA Region IV to Mr. Ron Methier, Georgia EPD"); SOB at 143-44 (making no mention of regional approval).

*standards.*

Reliance on this statement is inappropriate. First, the regulations require Regional approval on a case-by-case basis. It is therefore improper to rely on a determination for another facility in another state that occurred many years ago. Second, the statement is more than nine years old and hence, as taken up below, is extremely dated with respect to modeling capabilities.

KDAQ responded to this comment with the following:

> *The Division does not concur. Actual ozone modeling is not required or technically feasible. In the absence of a regulatory model for near field ozone impacts, the Division deemed the "analytical procedure" conducted by the applicant applicable for demonstration purposes in accordance with 40 CFR Part 51 Appendix W at Subsection 3.2.2. As stated in section 5.2.1 of Appendix W, the choice of method to assess the impact of an individual source depends on the nature of the source and its emissions. Further, 401 KAR 51:052, Section 3(5) states: "For ozone, sources of VOCs or NOx locating outside a designated ozone nonattainment area shall be presumed to not have a significant impact on the designated nonattainment area. If ambient monitoring indicates that the area of source location is in fact nonattainment, the source shall be permitted pursuant to this administrative regulation and 401 KAR 52:020 until the area is designated nonattainment pursuant to 42 U.S.C. 7407(d)(1)(A)(i)." Additionally, the Division does not agree that reliance on the statement as referenced in December 2009 SOB at 46 is not applicable in the absence of the promulgation of a regulatory model for single source ozone impacts.*

RTC at J-117 to -118.

This statement does not sufficiently address Petitioners' comments so as to justify the ozone modeling failures. First, it affirms that KDAQ did not follow the correct procedure for receiving federal agency approval. Second, KDAQ ignores that the method chosen by the applicant must be an individual source modeling method, per the regulations. Third, it omits any support for its claim that actual ozone modeling is technically feasible, relying only on the assertion that modeling is not required because there is no "regulatory model for near field ozone impacts." As discussed below, actual ozone modeling is technically feasible. Fourth, the statement implicitly claims that the choice of the qualitative method was appropriate based on the nature of the source and the source's emissions, but provides no actual supporting information demonstrating how the approach is appropriate.[72] As set forth below, several factors weigh against using the Georgia-qualitative adaptation method.

[72] Nor does the Statement of Basis, *see* SOB at 143-44.

## B. The Qualitative Ozone Analysis Fails To Demonstrate Protection of the Ozone NAAQS.

Even if the qualitative approach could be termed modeling, it is not suitable, as it does not "provide[ ] the most accurate representation of atmospheric transport, dispersion, and chemical transformations in the area of interest." Appendix W Subsection 1.e. The Applicant and KDAQ made little to no effort to demonstrate that ozone modeling for Georgia is appropriate for Kentucky based on similarities in atmospheric transport, dispersion, and chemical transformations in the region surrounding the proposed facility. As EPA has noted, "the diversity of the nation's topography and climate, and variations in source configurations and operating characteristics" counsel against using the same recipe for modeling impacts from a source in one area as that used in another. *See* Appendix W Subsection 1.c. Here, significant differences exist between Kentucky and Georgia (both in terms of the topography/climate and source characteristics) that render the Georgia data inappropriate for use in this case.

The qualitative impact analysis submitted by Kentucky Syngas is inadequate since it is based on the Georgia ozone modeling results that are:

1. Not valid in Kentucky due to large differences in emissions of ozone precursors ($NO_x$ and VOC), terrain, land use, wind and other atmospheric conditions that affect ozone formation. Precursor emissions are different in terms of both source types and quantity. Recent VISTAS inventories show that $NO_x$ and VOC emissions from onroad mobile sources in Georgia are much larger (twice for $NO_x$ and more than 180% for VOC) than those in Kentucky.[73] Kentucky has about 33% more $NO_x$ emissions from utilities than Georgia.[74]
2. Based on reductions in non-power plant anthropogenic emissions (e.g., urban vehicular emissions), rendering the results not applicable to an elevated point source such as Kentucky Syngas.
3. Based on reductions in $NO_x$ reductions at existing power plants, again rendering the results inapplicable to a new power plant such as Kentucky Syngas.
4. Focused on ozone impacts in large cities such as Atlanta while the Kentucky Syngas facility will impact mostly rural areas.

KDAQ responded to Petitioners' comments on this issue by stating as follows:

[73] *See* Exhibit 48, Maureen Mullen, 2003. VISTAS 2002 Draft Onroad Mobile Inventory.

[74] *See* Exhibit 49, Edward Sabo, 2003. 2002 Southeast Emissions Inventory Development.

*The Division does not concur. In the absence of a regulatory model for single source ozone impacts, the Division deemed the "analytical procedure" conducted by the applicant applicable for demonstration purposes in accordance with Appendix W at Subsection 3.2.2. Further, the qualitative procedure is conservative due to the urban areas modeled and the higher ratio of cumulative NOx to VOC emitted in Kentucky in comparison to Georgia (1:2 vs. 2:9) as determined by comparison of U. S. EPA emissions data found at the following websites:*
*http://www.epa.gov/air/emissions/nox.htm,*
*http://www.epa.gov/air/emissions/voc.htm,*
*ftp://ftp.epa.gov/EmisInventory/2002finalnei/biogenic_sector_data/.*

Again, the agency's response is inadequate. KDAQ continues to rely on a conclusory and unsupported statement that the agency made its determination in accordance with Subsection 3.2.2. KDAQ also failed to address Petitioners' comments about differences in terrain, land use, atmospheric conditions and relative source contribution, and does not compare the significance of these impacts to the significance of the cited conservative factors. Finally, the conclusion drawn by KDAQ about deriving the relative ozone impact from the $NO_x$ to VOC ratio has been discredited.[75] The ratio could just as well go in the opposite direction, and the only way to know for sure is to run the actual models. For these reasons, KDAQ has not demonstrated that the qualitative approach provides the most accurate representation of atmospheric transport, dispersion, and chemical transformations in the area of interest.

In addition, ozone precursors emitted by proposed power plants in Kentucky have been shown to cause significantly large ozone increases. In a December 2001 modeling study by the Kentucky Natural Resources and Environmental Protection Cabinet, the photochemical model CMAQ was used by EPA to show that new power plants in Kentucky can generate 8-hour ozone increases up to 11 ppb.[76] These large ozone increases were found to "occur in the western part of the state, close to where new power plants are proposed."[77] This cumulative study also shows that Muhlenberg County has the largest daily total of $NO_x$ emissions (16.52 tpd) from new power plants.

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[75] Exhibit 50, Letter from Richard D. Scheffe, Senior Science Advisor, EPA, OAQPS, to Abigail Dillen, July 28, 2006 (stamped August 3, 2006).

[76] *See* Exhibit 51, Kentucky NREPC, *A Cumulative Assessment of the Environmental Impacts Caused by Kentucky Electric Generating Units*, 2001.

[77] *Id.* at 31.

Muhlenberg County has no ozone monitor and the September 2009 ozone analysis submitted by Kentucky Syngas has estimated an ozone background of 0.071 ppm that is based on the 2006-2008 measurements at the Warren County monitoring station. While this background is below the 2008 AAQS of 0.075 ppm, it will exceed the new lower standard between 0.06 and 0.07 ppm that has recently been proposed by the EPA. 8-hour ozone measurements in neighboring Christian County have largely exceeded the 2008 AAQS of 0.075 ppm. The EPA AirData website has indicated that a 4$^{th}$ maximum 8-hour concentration of 0.089 ppm was recorded in 2007 in Christian County. As a result of high ozone measurements, Christian County has been proposed in March 2009 by KDAQ as non-attainment (letter dated March 12, 2009 from L.K. Peters, Secretary of Kentucky Energy and Environment Cabinet to A.S. Meiburg, Acting Regional Administrator, EPA Region 4). Thus, Muhlenberg County may have an ozone problem that will get worse since the proposed Kentucky Syngas and other planned facilities will increase ozone concentrations. Moreover, EPA has recently proposed to lower the 2008 8-hour ozone standard of 0.075 ppm to between 0.06 and 0.07 ppm.

KDAQ responded to this comment by citing the stay of the 0.075 ppm ozone NAAQS and concluding that Muhlenberg County cannot be considered non-attainment for ozone. RTC at J-119 to -120. KDAQ misses a significant point of Petitioners' comment: to highlight the ozone problem in Muhlenberg County as it informs the need for more stringent and individualized quantitative analysis of ozone impacts. KDAQ once more fails to show that its approved approach ensures protection of the ozone NAAQS.

Moreover, since issuance of the Georgia letter in 2000, significant advances have been made in the available modeling processes for ozone impacts from individual sources. Photochemical Models such as CMAQ are available and appropriate for such analyses, in that (a) they have been peer reviewed, (b) they are applicable to individual source ozone modeling on a theoretical basis, (c) the necessary databases are available and adequate, (d) performance evaluations show they are not biased toward underestimates, and (e) a protocol on methods and procedures to be followed has been established. Appendix W Subsection 3.2.2(e). With readily available modeling databases such as the KY NREPC cumulative study and more recent modeling studies (e.g., the Kentucky ozone SIP and VISTAS regional modeling), it is fairly fast and inexpensive to perform such modeling analyses. Further, in recent years, several enhancements such as the use of fine grid resolution (4 km or less) and plume-in-grid treatment have made photochemical models like CAMx and CMAQ more suitable for predicting ozone impacts from large $NO_x$ plumes from power plants. These models have recently been applied to large point sources such as power plants in Kansas, Missouri, Oklahoma and Texas, as summarized in a presentation by EPA staff.[78] Recently, AMI Environmental has utilized the CAMx model with a 2-km grid to assess the ozone impacts of the proposed White Stallion on ozone air quality in Houston.[79] An individual source analysis using these models would provide a significantly more accurate estimation of ozone impacts in the project area than does a qualitative analysis based on dated and out-of-state information. Single source modeling is especially important, given the issues in Muhlenberg County and the ozone NAAQS revision described above.

KDAQ responded to these comments with the following statements:

> *The Division does not concur. In the absence of a regulatory model for single source ozone impacts, the Division deemed the "analytical procedure" conducted by the applicant applicable for demonstration purposes in accordance with Appendix W at Subsection 3.2.2. Furthermore, without the existence of regional ozone inventories for use in a regulatory single source model for ozone, an ozone NAAQS modeling analysis for PSD purposes is inappropriate and technically infeasible.*

RTC at J-121. KDAQ's statement about the absence of a regulatory model does not address Petitioners' comments about the feasibility of conducting ozone modeling. The examples cited by Petitioners show that such modeling is feasible. In addition, Petitioners cited several sources of inventory information that KDAQ can use for the required ozone modeling. For these reasons, the Applicant and KDAQ have not ensured protection of the ozone NAAQS.

## XIII. THE PERMIT LACKS THE NECESSARY $PM_{2.5}$ BACT LIMIT.

KDAQ's use of $PM_{10}$ as a surrogate for $PM_{2.5}$ is impermissible for BACT purposes. The Administrator must therefore object to the Permit on that basis.

Although KDAQ identified $PM_{2.5}$ as a pollutant subject to BACT, SOB at 6, 19, the Permit does not include a BACT limit for $PM_{2.5}$ emissions, instead using $PM_{10}$ as a surrogate for

[78] Exhibit 52, Snyder, Erik and Bret Anderson, 2005. *Single Source Ozone/PM2.5 in Regional Scale Modeling and Alternate Methods.*

[79] *See* Exhibit 53, Khanh Tran, *Photochemical Modeling of Ozone Impacts of the Proposed White Stallion Energy Center.* Report prepared for Environmental Integrity Project, Austin, Texas. October 2009.

$PM_{2.5}$. *E.g.*, Permit at 20. Because $PM_{2.5}$ is a regulated pollutant that will be emitted in a significant amount, a BACT limit for $PM_{2.5}$ is required, and KDAQ's justification for $PM_{10}$ surrogacy is insufficient. 42 U.S.C. § 7475(a)(4); 40 C.F.R. § 52.21(j).

EPA has recently confirmed that using $PM_{10}$ as a surrogate for $PM_{2.5}$ is seldom legally defensible. In the Trimble Order, EPA granted in part a petition seeking EPA's objection because of the permit's lack of a $PM_{2.5}$ limit. In that order, EPA stated that:

> EPA establishes NAAQS for certain pollutants, pursuant to Section 109 of the CAA, 42 U.S.C. § 7409. Once a NAAQS is established, the CAA sets forth a process for designating areas in the nation as attainment, nonattainment, or unclassifiable, thus triggering additional requirements consistent with the CAA and its implementing regulations. Following establishment of a NAAQS, EPA also promulgates implementation rules that provide specific details of how states must comply with the NAAQS based on the corresponding designations for areas within the state. Generally, the SIP is the primary means by which states comply with CAA requirements to attain the NAAQS. *See* CAA Section 110(a) and Sections 171 - 193, 42 U.S.C. § 7410(a) and §§ 7501 - 7515.
>
> On July 28, 1997, EPA revised the NAAQS for PM to add new standards for "fine" particulates, using $PM_{2.5}$ as the indicator. 62 *Fed. Reg.* 39,852 (July 28, 1997). On October 17, 2006, EPA revised the NAAQS for both $PM_{2.5}$ and $PM_{10}$. 71 *Fed. Reg.* 61,236 (October 17, 2006). On October 23, 1997, EPA issued a memorandum from John S. Seitz regarding implementation of the 1997 standards entitled, *"Interim Implementation/or the New Source Review Requirements/or PM25"* (Seitz Memorandum). The Seitz Memorandum explained that sources would be allowed to use implementation of a $PM_{10}$ program as a surrogate for meeting $PM_{2.5}$ NSR requirements until certain technical difficulties were resolved. Seitz Memorandum at 1. On April 5, 2005, EPA issued a second guidance memorandum from Stephen D. Page entitled, *"Implementation of New Source Review Requirements in PM-2.5 Nonattainment Areas"* (Page Memorandum), which re-affirmed the October 23, 1997 Memorandum. Page Memorandum at 1. On May 16, 2008, EPA promulgated the final rule entitled "Implementation of the New Source Review (NSR) Program for Particulate Matter Less than 2.5 Micrometers ($PM_{2.5}$) (May 2008 PM25 NSR Implementation Rule). 96 [sic] *Fed. Reg.* 28,321 (May 16, 2008). In the preamble to that rule, EPA explained the

transition to the $PM_{2.5}$ NSR requirements beginning on page 28,340. Specifically, EPA concluded that, if a SIP-approved state is unable to implement a PSD program for the PM2.S NAAQS based on that rule, the state may continue to implement a $PM_{10}$ program as a surrogate to meet the PSD program requirements for $PM_{2.5}$ under the $PM_{10}$ Surrogate Policy in the Seitz Memorandum [a/k/a EPA's 1997 Surrogate Policy]. 96 [sic] *Fed. Reg.* at 28,340-28,341.

*Use of $PM_{10}$ as a Surrogate for $PM_{2.5}$*

When EPA issued the $PM_{10}$ Surrogate Policy in 1997, the Agency did not identify criteria to be applied before the policy could be used for satisfying the $PM_{2.5}$ requirements. However, courts have issued a number of opinions that are properly read as limiting the use of $PM_{10}$ as a surrogate for meeting the PSD requirements for $PM_{2.5}$. Applicants and state permitting authorities seeking to rely on the $PM_{10}$ Surrogate Policy should consider these opinions in determining whether $PM_{10}$ serves as an adequate surrogate for meeting the $PM_{2.5}$ requirements in the case of the specific permit application at issue.

Courts have held that a surrogate may be used only after it has been shown to be reasonable to do so. *See, e.g., Sierra Club v. EPA,* 353 F.3d 976, 982-984 (D.C. Cir. 2004) (stating general principle that EPA may use a surrogate if it is "reasonable" to do so and applying analysis from *National Lime Assoc. v. EPA,* 233 F.3d 625, 637 (D.C. Cir. 2000) that is applicable to determining whether use of a surrogate is reasonable in setting emissions limitations for hazardous air pollutants under Section 112 of the Act); *Mossville Envt'l Action Now* v. *EPA*, 370 F. 3d 1232, 1242-43 (D.C. Cir. 2004) (EPA must explain the correlation between the surrogate and the represented pollutant that provides the basis for the surrogacy); *Bluewater Network* v. *EPA,* 370 F.3d 1, 18 (D.C. Cir. 2004) ("The Agency reasonably determined that regulating [hydrocarbons] would control PM pollution both because HC itself contributes to such pollution, and because HC provides a good proxy for regulating fine PM emissions"). Though these court decisions do not speak directly to the use of $PM_{10}$ as a surrogate for $PM_{2.5}$, EPA believes that the overarching legal principle from these decisions is that a surrogate may be used only after it has been shown to be reasonable (such as where the surrogate is a reasonable proxy for the pollutant or has a predictable correlation to the pollutant). Further, we believe that this case law governs the use of EPA's $PM_{10}$ Surrogate Policy, and thus that the legal principle from the case law applies where a permit applicant or state permitting authority seeks to rely upon the $PM_{10}$ surrogate policy in lieu of a $PM_{2.5}$ analysis to obtain a PSD permit.

With respect to PM surrogacy in particular, there are specific issues raised in the case law that bear on whether $PM_{10}$ can be considered a reasonable surrogate for $PM_{2.5}$. The D.C. Circuit has concluded that $PM_{10}$ was an arbitrary surrogate for a PM pollutant that is one fraction of $PM_{10}$ where the use of $PM_{10}$ as a surrogate for that fraction is inherently confounded" by the presence of the other fraction of $PM_{10}$. *ATA v. EPA,* 175 F.3d 1027, 1054 (D.C. Cir. 1999) ($PM_{10}$ is an arbitrary indicator for coarse PM ($PM_{10}$-$_{2.5}$) because the amount of coarse PM within $PM_{10}$ will depend arbitrarily on the amount of fine PM ($PM_{2.5}$)) In another case, however, the D.C. Circuit held that the facts and circumstances in that instance provided a reasonable rationale for using $PM_{10}$ as a surrogate for $PM_{2.5}$. *American Farm Bureau v. EPA,* 559 F.3d 512, 534-35 (D.C. Cir. 2009) (where record demonstrated that (1) $PM_{2.5}$ tends to be higher in urban areas then in rural areas, and (2) evidence of health effects from coarse PM in urban areas is stronger, EPA reasoned that setting a single $PM_{10}$ standard for both urban and rural areas would tend to require lower coarse PM concentrations in urban areas. The court considered the reasoning from the *ATA* case and accepted that the presence of $PM_{2.5}$ in $PM_{10}$ will cause the amount of coarse PM in $PM_{10}$ to vary, but on the specific facts before it held that such variation was not arbitrary). EPA believes that these cases demonstrate the need for permit applicants and permitting authorities to determine whether $PM_{10}$ is a reasonable surrogate for $PM_{2.5}$ under the facts and circumstances of the specific permit at issue, and not proceed on a general presumption that $PM_{10}$ is always a reasonable surrogate for $PM_{2.5}$.

This case law suggests that any person attempting to show that $PM_{10}$ is a reasonable surrogate for $PM_{2.5}$ would need to address the differences between $PM_{10}$ and $PM_{2.5}$. For example, emission controls used to capture coarse particles in some cases may be less effective in controlling for $PM_{2.5}$. 72 *Fed. Reg.* 20,586, 20,617 (April 25, 2007)... [For example], the particles that make up $PM_{2.5}$ may be transported over long distances while coarse particles normally travel only short distances. 70 *Fed. Reg.* 65,984, 65,997-98 (November 1, 2005). Under the principles in the case law, any person seeking to use the $PM_{10}$ Surrogate Policy properly would need to consider these differences between $PM_{10}$ and $PM_{2.5}$ and demonstrate that $PM_{10}$ is nonetheless an adequate surrogate for $PM_{2.5}$.

Finally, the $PM_{10}$ Surrogate Policy contains limits. As stated in the 1997 Seitz Memorandum, the $PM_{10}$ Surrogate Policy provided that, in view of significant technical difficulties that existed in 1997, EPA believed that $PM_{10}$ may properly be used as a surrogate for $PM_{2.5}$ in meeting NSR requirements "until these difficulties are resolved." Seitz Memorandum at 1.... EPA noted in the May 2008 $PM_{2.5}$ NSR Implementation Rule that "these difficulties have largely been resolved." 73 *Fed. Reg.* at 28,340/2-3.

In this case, the record for the LG&E permit does not provide an adequate rationale to support the use of $PM_{10}$ as a surrogate for $PM_{2.5}$ under the circumstances for this specific permit. Overall, the record does not show how the use of the $PM_{10}$ Surrogate Policy is consistent with the case law discussed above in light of the differences between $PM_{10}$ and $PM_{2.5}$, and does not demonstrate that the use of the Policy here falls within the limits of the Policy. For these reasons and based on the record now before EPA, the Petition is granted on the claim that the permit record does not support the use of $PM_{10}$ as a surrogate for $PM_{2.5}$.

Going forward and without suggesting that the following two steps are necessary or sufficient to demonstrate that $PM_{10}$ is a reasonable surrogate for $PM_{2.5}$, we offer the following as a possible approach to making that demonstration:

First, the source or the permitting authority establishes in the permit record a strong statistical relationship between $PM_{10}$ and $PM_{2.5}$ emissions from the proposed unit, both with and without the proposed control technology in operation. Without a strong correlation, there can be little confidence that the statutory requirements will be met for $PM_{2.5}$ using the controls selected through a $PM_{10}$ NSR analysis. A strong statistical relationship could be established in a variety of ways. In the case where the unit in question is a new unit, the applicant could rely on emissions data from similar units at the facility or at other facilities to develop a correlation that demonstrates the relationship between the two species. In the alternative, if actual emissions test data are not available for a similar unit, the applicant may be able to access and analyze the underlying source test data that has been used to develop emission factors for sources of the same type (including the type of control equipment). In developing such correlation, a simple ratio of AP-42 emissions factors or of the results of a single compliance stack test would not appear to be sufficient. Instead, reasonable consideration would be given to whether and how the $PM_{2.5}/PM_{10}$ ratio may vary with source operating conditions, including variations in the fuel rate and in control equipment condition and operation. This consideration may be based on engineering analysis of the facility including the proposed control technology and/or review of existing or new emissions test data across a range of conditions at existing sources that are similar in design to the proposed unit.

Second, the source or the permitting authority demonstrates that the degree of control of $PM_{2.5}$ by the control technology selected in the $PM_{10}$ BACT analysis will be at least as effective as the technology that would have been selected if a BACT analysis specific to $PM_{2.5}$ emissions had been conducted. We present here two possible paths to accomplish this. The first would be to perform a $PM_{2.5}$-specific BACT analysis, in which case the requirement is met if the control technology selected through the $PM_{10}$ BACT analysis is physically the same as what is selected through the PM22.5 BACT analysis, in all respects that may affect control efficiency for $PM_{2.5}$. The second path would be to perform a $PM_{2.5}$-specific BACT analysis, and show that while the type and/or physical design of the control technology may be different, the efficiency for $PM_{2.5}$ control of the technology selected through the $PM_{10}$ BACT analysis is equal to or better than the efficiency of the technology selected through the $PM_{2.5}$ BACT analysis, across the range of operating conditions that can be anticipated for the source and the control equipment. This demonstration may be based on engineering review and/or old or new emissions test data from units and control equipment similar to the proposed unit with the proposed control equipment.

Again, these two steps are not intended to be the exclusive list of possible demonstrations that a source or permitting authority would make to show that $PM_{10}$ is a reasonable surrogate for $PM_{2.5}$. Sources and permitting authorities are encouraged to carefully consider the case law and the limits of the Surrogate Policy to determine what information and analysis would need to be included in the permit application and record before relying on the Surrogate Policy.

Exhibit 6, Trimble Order at 42-46. It is also Petitioners' understanding that EPA Region IV has issued guidance to state agencies directing them to explicitly justify $PM_{10}$ surrogacy as directed in the Trimble Order—which KDAQ has not done.

KDAQ's analysis of $PM_{10}$ surrogacy for $PM_{2.5}$ in this case does not satisfy the requirements set forth in the Trimble Order. Trimble Order at 42-46. KDAQ's demonstration in this case consisted of a "Reasonability Analysis." SOB at 6-14. KDAQ concluded that "Kentucky Syngas has demonstrated that for each emission point at the proposed site (1) the available data show a consistent relationship between $PM_{2.5}$ and $PM_{10}$ emissions and (2) the pollution control technologies that establish BACT for $PM_{10}$ are the best technologies for controlling $PM_{2.5}$." SOB at 6-7. KDAQ's analysis, however, does not meet the requirements of the rigorous analysis required by the Trimble Order. Trimble Order at 42-46.

Initially, the "reasonability analysis" does not satisfy either of the two approaches EPA identified as potential ways to demonstrate $PM_{10}$ is a reasonable surrogate for $PM_{2.5}$. Trimble Order at 45. Neither the Applicant nor KDAQ established a strong statistical relationship between $PM_{10}$ and $PM_{2.5}$ emissions from the proposed units, and certainly neither has utilized the methods set forth in the Trimble Order for evaluating this statistical relationship. *Id.* at 45. The Trimble Order does not just require a "consistent relationship between $PM_{2.5}$ and $PM_{10}$ emissions" as KDAQ describes it in the SOB (at page 7), but a "strong statistical relationship" demonstrated by one of two approaches. *Id.*

Additionally, KDAQ has not demonstrated that the degree of control of $PM_{2.5}$ by the control technology selected in the $PM_{10}$ BACT analysis will be at least as effective as the technology that would have been selected in a $PM_{2.5}$ BACT analysis, or even performed a $PM_{2.5}$-specific BACT analysis, as the Trimble Order directs. Trimble Order at 45. KDAQ has also failed to satisfy EPA's general directive that it otherwise demonstrate the use of the $PM_{10}$ Surrogate Policy must be consistent with the case law discussed in the Trimble Order in light of the differences between $PM_{10}$ and $PM_{2.5}$. Trimble Order at 44-45.

Instead, KDAQ's chart contains conclusory statements that $PM_{10}$ is an appropriate surrogate for the Kentucky Syngas units. KDAQ's surrogacy conclusion is erroneous. KDAQ repeatedly cites to Chapter 13 of AP-42, which includes $PM_{2.5}$ multipliers and was revised in 2006. *See* SOB at 7, 8, 10, 13. First, the inclusion of a multiplier in no way speaks to whether there is a strong statistical relationship. The inclusion of the multiplier was based upon two underlying documents, neither of which KDAQ cited.[80] Without any discussion of the implications of these documents, it is not possible to understand the reasoning or analysis behind the multipliers and KDAQ cannot reasonably draw any conclusion from them regarding the statistical relationship between $PM_{2.5}$ and $PM_{10}$.

Second, even if the 2006 update could have been relied on at one time, that update is no longer current. As the Trimble Order acknowledges, in 2008 EPA declared that the technical difficulties associated with $PM_{2.5}$ – which justified the surrogacy approach in the first place – "have largely been resolved." Trimble Order at 44 (quoting 73 Fed. Reg. at 28,340/2-3). Thus, even assuming that $PM_{2.5}$ surrogacy is permissible at all, KDAQ certainly cannot rely on this outdated chapter from AP-42.

Third, the Trimble Order emphasized the need to consider the facts and circumstances of the permit at issue and not rely on generalities:

> EPA believes that these cases demonstrate the need for permit applicants and permitting authorities to determine whether $PM_{10}$ is a reasonable surrogate for $PM_{2.5}$ under the facts and circumstances of the specific permit at issue, and not proceed on a general presumption that $PM_{10}$ is always a reasonable surrogate for $PM_{2.5}$.

Trimble Order at 44. Any reliance on "multipliers," or AP-42 generally, by definition fails to consider "the fact and circumstances of the specific permit at issue." *Id.* The generic AP-42 multipliers are not specific to Kentucky Syngas, syngas plants in general, or the particulars of this Permit. Thus, any reliance on AP-42 fails to meet the requirements of the Trimble Order.

Furthermore, in the portion of the analysis for Feedstock Storage and Preparation: Enclosed Sources without Fabric Filters, Feedstock Storage and Preparation: Fugitive Sources, and Byproduct Storage and Handling there is no authority for the conclusion that "[w]et suppression is reasonably assumed to have the same effectiveness controlling $PM_{2.5}$ as it does with $PM_{10}$." The only cited authority for this conclusion is AP-42 Chapter 13.2.4, which contains no discussion of the effectiveness of wet suppression for $PM_{2.5}$ compared to $PM_{10}$.[81] In

[80] The documents were C. Cowherd, *Background Document for Revisions to Fine Fraction Ratios Used for AP-42 Fugitive Dust Emission Factors* (February 2006) and *Fugitive Particulate Matter Emissions*, EPA Contract No. 68-D2-0159, Work Assignment No. 4-06, Midwest Research Institute, Kansas City, MO (April 1997).

[81] The whole discussion of PM controls from AP-42 Chapter 13.2.4 is as follows:

addition, in the entry for Ancillary Equipment: Paved and Unpaved Haul Roads, there is not even a conclusion as to the relationship between $PM_{2.5}$ and $PM_{10}$, just that control options would have "comparable effectiveness." SOB at 13. This falls far short of the showing necessary to justify surrogacy. The EPA in Trimble did not call for "comparable" effectiveness; rather, the agency required that $PM_{10}$ controls be at least as effective as controls for $PM_{2.5}$. This means that the degree of $PM_{2.5}$ control must be as great or greater. Finally, even if all the problems with KDAQ's reliance on AP-42 could be set aside, KDAQ's surrogacy approach would still fail, because the wet suppression relied upon must be *chemical suppression* for effective PM control. *See* AP-42 Section 13.2.4-5. The Permit, nonetheless, allows the use of water as a suppression method: "Application and maintenance of asphalt, oil, water, or suitable chemicals on roads, material stockpiles, and other surfaces which can create airborne dusts." Permit at 85. Consequently, for Feedstock Storage and Preparation: Enclosed Sources without Fabric Filters, Feedstock Storage and Preparation: Fugitive Sources, Byproduct Storage and Handling, and Ancillary Equipment: Paved and Unpaved Haul Roads, KDAQ's surrogacy analysis fails both prongs of the Trimble test. Trimble Order at 45-46.

As for the SNG Production Process, the Ancillary Equipment: Natural Gas/SNG-Fired Auxiliary Boiler and Process Heater, Sulfur Recovery Process: ABS Tower Vent, and Ancillary Equipment: Diesel Driven Engines, KDAQ concluded for all of them that all $PM_{10}$ is $PM_{2.5}$, citing AP-42 Chapters 1.4, 3.3 and 3.4. SOB at 6, 7, 9, 11. This conclusion misses a critical logical step and a key prong of the Trimble Order. For the reasons stated above as to why the AP-42 is not appropriate (it is both generalized and outdated), here again AP-42 does not provide sufficient or reliable data that could justify a surrogacy approach for these units. Further, these portions of KDAQ's analysis lack *any* assessment of or conclusions related to the control options. Simply because all $PM_{10}$ is $PM_{2.5}$ does not lead inexorably to the conclusion that the appropriate controls for $PM_{10}$ are also the appropriate controls for $PM_{2.5}$. This is underscored by

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> Watering and the use of chemical wetting agents are the principal means for control of aggregate storage pile emissions. Enclosure or covering of inactive piles to reduce wind erosion can also reduce emissions. Watering is useful mainly to reduce emissions from vehicle traffic in the storage pile area. Watering of the storage piles themselves typically has only a very temporary slight effect on total emissions. A much more effective technique is to apply chemical agents (such as surfactants) that permit more extensive wetting. Continuous chemical treating of material loaded onto piles, coupled with watering or treatment of roadways, can reduce total particulate emissions from aggregate storage operations by up to 90 percent.

a point made in AP-42: PM from natural gas combustion "has filterable and condensable fractions." AP-42 1.4-3. Condensable PM is $PM_{2.5}$, not $PM_{10}$. The controls used for $PM_{10}$ or filterable PM are not effective for condensable PM. In fact, the lack of information in 2006 regarding condensable PM is underscored by Chapter 1.4's poor rating for the condensable PM emissions factor: *See* AP-42 at 1.4-6 ("D" rating). The SOB also concludes that all the PM for these units will be below 1 micron in diameter. That is especially significant. Particles less than 1 micrometer in diameter are termed submicrometer particles, are common in many types of combustion, and can be the most difficult size to collect. If all the PM will be $PM_{2.5}$ and less than 1 micron, the controls must be specifically tailored to $PM_{2.5}$ (or smaller) and the condensable fraction. In sum, the surrogacy analysis for these units fails to meet half of the requirements from the Trimble Order.

As to the Sulfur Recovery Process: ABS Tower Vent specifically, this section goes on to select "high efficiency fiber bed filters" as BACT. As discussed above, a BACT analysis for $PM_{10}$, when all $PM_{10}$ is $PM_{2.5}$, is inappropriate. Second, a control method for filterable PM (such as the one selected by KDAQ) is inappropriate for PM from natural gas combustion, which "has filterable and condensable fractions." AP-42 1.4-3. Third, this section relies on 74 Fed. Reg. 12970. This citation for a selection of control equipment is inadequate considering there is no discussion in this Federal Register notice of control equipment, of high efficiency fiber bed filters, or of PM filters at all. In fact, this Federal Register notice discusses only "Methods for Measurement of Filterable $PM_{10}$ and $PM_{2.5}$ and Measurement of Condensable Particulate Matter Emissions." Consequently, this portion of the analysis fails the second prong of the Trimble Order, which requires scrutiny sufficient to conclude that the $PM_{10}$ controls are at least as effective as controls for $PM_{2.5}$. Trimble Order at 45.

For Ancillary Equipment: Cooling Towers, the analysis itself runs directly counter to the Trimble factors. SOB at 10. First, instead of establishing a statistically significant relationship, as the Trimble Order requires, the Applicant admits that (1) there is a lack of PM test data on cooling towers; (2) the relationship is "theoretical"; and (3) the relationship can vary. Application, Appx. G, at 15-18. As to PM emissions estimates, the Applicant concedes that "prediction of particle size distribution of drift from a cooling tower is subject to great uncertainty." *Id.* at 17. The Applicant goes on to use this as the basis to conclude that $PM_{10}$ can act a surrogate for $PM_{2.5}$ instead of coming to the opposite conclusion required by the Trimble

Order. *Id.* The SOB gives this even shorter shrift. SOB at 10. Once again, the analysis fails to even address the second prong of the Trimble test as to controls and whether the controls for $PM_{10}$ are at least as effective as the controls for $PM_{2.5}$. Trimble Order at 45. For these reasons, the Applicant and KDAQ's surrogacy analysis must be rejected.

In its Response to Comments, KDAQ did not directly address the substance of Petitioners' comments. Instead, the agency noted that the surrogacy approach set forth in the Trimble Order need not be followed, and then the agency references a September 21, 2009, reasonableness analysis submitted by Kentucky Syngas. RTC at J-88 (citing Application, Appx. G, Reasonableness Analysis for $PM_{10}$ as a Surrogate for $PM_{2.5}$). The document submitted by Kentucky Syngas, however, does not address the substantive concerns raised in Petitioners' comments. Moreover, the credibility of Kentucky Syngas's submission is questionable, given that the company devoted the first four pages of the document to arguing that the Trimble Order is illegal. *See, e.g.*, Appx. G at 4 (citing "the illegality of EPA's actions"). In any event, neither KDAQ nor Kentucky Syngas have demonstrated that the surrogacy approach they employed satisfied the standards set forth in the Trimble Order. Because the requirements for surrogacy have not been met, the Administrator must object to this Permit.

## XIV. CONCLUSION

For the above reasons, the Permit fails to comply with all applicable requirements, and the Administrator must object. Petitioners have demonstrated that the Permit was issued based on numerous procedural and substantive errors. The Administrator must direct KDAQ to correct its errors by revising or revoking the Permit. To this end, the Administrator should include in her order specific terms and conditions necessary to remedy the inadequacies described in this petition. *See* 40 C.F.R. § 70.8(c)(2) ("Any EPA objection under paragraph (c)(1) of this section *shall* include… a description of the *terms and conditions that the permit must include* to respond to the objections") (emphasis added).

Respectfully submitted,

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On behalf of:
SIERRA CLUB
VALLEY WATCH, INC.

DATED: October 27, 2010

BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

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In the Matter of the Final Operating Permit for:

Kentucky Syngas, LLC, to operate the proposed source located northeast of Central City in Muhlenberg County, Kentucky

Permit No. V-09-001
Source I.D. No. 21-177-00089

Proposed by the Commonwealth of Kentucky, Energy and Environment Cabinet

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CERTIFICATE OF SERVICE

I make this statement under oath and based on personal knowledge. On this day, July 23rd, 2010, I caused to be served upon the following persons a copy of ELPC's Petition to the United States Environmental Protection Agency in the matter of the Final Operating Permit for Kentucky Syngas, LLC, to operate the proposed source located northeast of Central City in Muhlenberg County, Kentucky via electronic mail and U.S. Post.

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