BEFORE THE ENVIRONMENTAL APPEALS BOARD
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C.

	)	
IN THE MATTER OF:	)	Appeal No. PSD 09-___
MGP INGREDIENTS OF	)	
ILLINOIS, INC.	)	Illinois PSD Permit No.
	)	

PETITION FOR REVIEW AND REQUEST FOR ORAL ARGUMENT

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INTRODUCTION

Pursuant to 40 C.F.R. § 124.19(a), the Sierra Club ("Petitioner"), petitions for review of the conditions of the Prevention of Significant Deterioration (PSD) Approval Number 179060AAD which the Illinois Environmental Protection Agency ("IEPA") issued for a nominal 493 million British Thermal Unit (MMBtu) solid-fuel-fired boiler, a natural-gas-fired auxiliary boiler, and associated equipment at the MGP Ingredients of Illinois, Inc. ("MGP") facility in Pekin, Illinois, on June 22, 2009. A copy of the PSD permit is attached as Sierra Club **Exhibit 1**.

The State of Illinois is authorized to administer the PSD permit program pursuant to a delegation of authority by the United States Environmental Protection Agency ("EPA"). The Permit authorizes MGP to modify an existing source of air pollution by adding various equipment related to steam generation at the plant. Specifically, the permit states:

> Permit is hereby granted to the above-designated Permittee to CONSTRUCT emission source(s) and/or air pollution control equipment consisting of a solid fuel-fired boiler with low-NOx burners, a selective catalytic reduction (SCR) system, scrubber system and baghouse; with associated fuel and ash storage and handling systems with baghouses, an auxiliary boiler, and other ancillary operations, as described in [Application No.: 07030058].

Ex. 1 at 1. Because the permit fails to include necessary permit conditions, make certain necessary findings, is based on various erroneous legal interpretations and faulty conclusions, lacks a sufficient basis in the record, and raises important policy considerations that the Board should address, review is appropriate pursuant to 40 C.F.R. pt. 124.

THRESHOLD PROCEDURAL REQUIREMENTS

Petitioner Sierra Club satisfies the threshold requirements for filing a petition for review under Part 124. Sierra Club has standing to petition for review of the permit decision because Sierra Club and its members participated in the public comment period on the draft permit. 40 CFR § 124.19(a). *See* Comments on behalf of the Sierra Club, attached as Sierra Club **Exhibit 2**; Transcript of Public Hearing, attached as Sierra Club **Exhibit 3**. The issues raised by Petitioner below were either raised with IEPA during the public comment period, or are directly related to the IEPA's response to public comments. Consequently, the Board has jurisdiction to hear Petitioner's timely request for review.

ISSUES PRESENTED FOR REVIEW

Petitioner respectfully requests Board review of the following issues:

(1) Whether IEPA's failure to include a best available control technology ("BACT") emission limit for carbon dioxide in the permit was a clearly erroneous conclusion of law or an important policy considerations that the Board should review and remand;

(2) Whether IEPA's analysis of clean fuels (natural gas and lower sulfur coal) in its top-down BACT analysis is clearly erroneous, including

   a. IEPA's comparison of its incremental cost-effectiveness calculation to a standard threshold for average cost-effectiveness;

b. IEPA’s sole reliance on incremental cost-effectiveness of clean fuels, without considering or analyzing average cost-effectiveness, contrary to EPA guidance;

c. IEPA’s rejection of clean fuels based on cost-effectiveness, without attempting to compare the cost-effectiveness of natural gas as a clean fuel control option at MGP to the cost at other facilities using natural gas;

d. IEPA’s rejection of natural gas and low sulfur coal as the basis of BACT, due to cost-effectiveness reasons, when the average cost-effectiveness of either natural gas or lower sulfur coal is well below the $10,000/ton threshold that IEPA purports to apply; and

e. IEPA’s failure to apportion annualized costs of pollution controls among all pollutants that will be controlled, contrary to EPA guidance for conducting BACT analyses.

(3) Whether IEPA’s failure to require compliance with the requirement to update BACT determinations for independent phases of the project that do not commence construction within eighteen months is a clearly erroneous error of law.

STATEMENT OF FACTS

MGP filed the application for this permit on March 22, 2007. Responsive Summary at 2, attached as Sierra Club **Exhibit 4**. Public hearings were held in July, 2008, and the comment period closed August 13, 2008. *Id*. at 2-3. IEPA issued the PSD permit for MGP on June 22, 2009. *Id*. at 2.

MGP's Pekin, Illinois, plant produced wheat gluten, wheat starch, ethanol and animal feed. Project Summary at 2, attached as Sierra Club **Exhibit 5**. The plant is currently shut down due to economic conditions. Responsiveness Summary (Ex 4) at 2. During the time when the plant operated, it obtained steam for its processes from a co-generation plant located next to the MGP plant and operated by Ameren. Project Summary (Ex 5) at 2; Responsiveness Summary (Ex 4) at 4. The applicant claims that Ameren is no longer interested in providing steam and will not renew its contract with MGP. Responsiveness Summary (Ex 4) at 4. For this reason, MPG claims a need to build new steam generation capacity at its facility. *Id*. MGP's primary objective is to remain in operation by constructing a boiler to provide process steam for its operations. *Id*. at 2, 4, 19. As a secondary purpose, MGP would prefer to also have the ability to cogenerate some electricity in addition to creating process steam. *Id*.

MGP proposes to build two boilers, firing one on natural gas and firing the other on coal, with the ability to burn other materials. The auxiliary (natural gas) boiler will be sufficient to provide all process steam for the facility, will be constructed first and used during construction of the solid-fuel boiler, and then as backup for the solid-fuel-boiler. *Id*. at 4, 51; Project Summary (Ex 5) at 2. The solid fuel boiler would have a heat capacity of 493 million Btus (MMBtu) per hour and would be equipped with a low NOx combustion system, overfire air, a selective catalytic reduction (SCR) system, a scrubber, and a fabric filter baghouse. Project Summary at 2. The natural gas boiler would have a heat input of 389 MMBtu per hour. *Id*. After the second—solid fuel—boiler was constructed, MGP would use the natural gas boiler "as a conventional auxiliary boiler, to supply steam when the main boiler is out of service for maintenance." *Id*.

REQUEST FOR LEAVE TO SUPPLEMENT

While the general bases for granting review are presented herein, Sierra Club seeks to further "demonstrate why the permitting authority's response to [Sierra Club's] objections warrants review" through a supplemental brief. EAB Practice Manual at 33. Due to the number and complexity of the issues and the apparent volume of record evidence that was developed by the agency after the public comment period (and which has not yet been provided to Sierra Club), Sierra Club respectfully requests that the Board allow Sierra Club to file a supplemental opening brief in support of this Petition, and extend the deadline for its filing for forty-five (45) days. The Board has granted requests, based on similar reasons, in the past. *See e.g., In re Desert Rock Energy Company, LLC*, PSD Appeal 08-03 & 08-04, Order (August 21, 2008) (granting petitioners' request to file supplemental briefing in support of petition for review of PSD permit and allowing 30 days for filing such briefs); *see In re BP Cherry Point,* 12 E.A.D. 209, 215 (EAB 2005) (allowing supplemental briefs to be filed more than a month after the petition for review); *In re Northern Michigan University,* Order Granting Motion for Extension of Time to File Response (July 10, 2008) (granting a 20 day extension to state agency to file response); *In re Deseret Power Electric Cooperative,* Order Granting Extension of Time (Feb. 12, 2008) (granting the applicant a 30 day extension); *In re ConocoPhillips Co.,* Order (Oct. 1,2007) (granting IEPA extension to file supplemental response). In fact, this case raises some of the same issues as were raised in the *Desert Rock* case, including the requirement to establish BACT limits for carbon dioxide, but involves additional facts and administrative proceedings that occurred since the *Desert Rock* petition was filed. *In re Desert Rock*, PSD Appeal No. 8/2/08 Order at 5 (noting that one of the issues in the case is BACT for CO_2 emissions). It is appropriate here, and fully within the Board's authority, to allow supplemental briefing and provide Sierra Club with additional time. *Desert Rock Energy Co., LLC*, PSD Appeal No. 08-03, Order (EAB August 21, 2008) ("the Board has discretion to relax or modify procedural rules for the orderly decision making process").

It took IEPA more than a year from the date of the permit application to issue a draft permit, and nearly another year to issue the proposed final permit after the public comment process. *See* Responsiveness Summary (Ex 4) at 2. This amount of time, alone, demonstrates that this project and the issues involved are complicated and that it is reasonable for Sierra Club to be allowed additional time to present its arguments for why the IEPA's permitting is deficient. Moreover, the IEPA's Response to Comments document contains various conclusions, but lacks most of the supporting calculations and documents that IEPA apparently developed and relied upon to respond to public comments. Sierra Club timely requested the full record for the permit, but has not yet received them from IEPA. On July 8, 2009, IEPA wrote to Sierra Club stating that it was unable to produce the record for the MGP permit within the time allowed under Illinois' Freedom of Information Act. *See* Letter from Vicky VonLanken, IEPA, to Rebecca Clayborn, Sierra Club (July 8, 2009), attached as Sierra Club's **Exhibit 6**. Sierra Club has still not received the records.

As Sierra Club demonstrates, below, IEPA's permit and Response to Comments is wrong in some respects, and lacking in others. However, on several of the issues raised in this Petition, the full measure of the Response to Comments and the permit at issue may depend on the underlying record. In such circumstances, supplemental briefing and an extension of time is appropriate. *See e.g., Desert Rock*, 8/21/08 Order a n.1 ("We also recognize that to the extent that the Region's response to comments may set forth technical analysis for the first time, or in greater detail, than was made available in the record for the draft permit… the petitioners may need to consult their experts in order to fully prepare their arguments on appeal.")

Therefore, Sierra Club respectfully requests that the Board allow Sierra Club to supplement this Petition for Review and set the deadline for doing so at least forty-five (45) days beyond the date that IEPA provides the permit record to Sierra Club pursuant to the Illinois Freedom of Information Act, to allow time to review those records, and to prepare a supplemental brief, as needed, based on that further documentation by IEPA. IEPA will not be prejudiced by this request as it will not affect any current deadlines or rights applicable to IEPA. The permittee will not be unduly prejudiced by an extension of forty-five days. The plant is not currently operating because of market conditions, though it has plans to open in the future. *See e.g.*, Responsiveness Summary (Ex 4) at 2 ("While MGP is currently not operating its Pekin plant because of market conditions, MGP has not abandoned its plans for the proposed facility.")

REQUEST FOR ORAL ARGUMENT

Petitioner also respectfully requests oral argument in the above-captioned matter. Oral argument would assist the Board in its deliberations on the issues presented by the case because the issue of best available control technology limits for carbon dioxides has been raised in other cases before this Board, and in other proceedings, and involves important, recurring issues for the Board and the U.S. Environmental Protection Agency.

Additionally, the issue of how to correctly calculate and apply cost-effectiveness of a clean fuel alternative in a top-down "best available control technology" analysis has significant potential importance to permitting agencies and this Board has not previously addressed some of the issues raised. Sierra Club believes that that oral argument could materially assist in the Board's resolution of these issues.

ARGUMENT

I. IEPA'S DETERMINATION THAT CARBON DIOXIDE IS NOT REGULATED UNDER THE CLEAN AIR ACT IS CLEARLY ERRONEOUS.

A. The Impacts of Carbon Dioxide Emissions On Human Health and Welfare Are Undeniable.

As the United States Supreme Court noted more than two years ago, the "enormity of the potential consequences associated with man-made climate change" and its resultant "harms . . . are serious and well recognized." *Massachusetts v. EPA*, 127 S.Ct. 1438, 1455, 1458 (2007). Indeed, the U.S. EPA recently agreed in its proposed endangerment finding for CO_2 (and other greenhouse gases):

> Concentrations of greenhouse gases are at unprecedented levels compared to the recent and distant past. These high atmospheric levels are the unambiguous result of human emissions, and are very likely the cause of the observed increase in average temperatures and other climatic changes. The effects of climate change observed to date and projected to occur in the future—including but not limited to the increased likelihood of more frequent and intense heat waves, more wildfires, degraded air quality, more heavy downpours and flooding, increased drought, greater sea level rise, more intense storms, harm to water resources, harm to agriculture, and harm to wildlife and ecosystems—are effects on public health and welfare within the meaning of the Clean Air Act.
>
> …
>
> The Administrator concludes that, in the circumstances presented here, the case for finding that greenhouse gases in the atmosphere endanger public health and welfare is compelling and, indeed, overwhelming. The scientific evidence described here is the product of decades of research by thousands of scientists from the U.S. and around the world. The evidence points ineluctably to the conclusion that climate change is upon us as a result of greenhouse gas emissions, that climatic changes are already occurring that harm our health and welfare, and that the effects will only worsen

> over time in the absence of regulatory action. The effects of climate change on public health include sickness and death. It is hard to imagine any understanding of public health that would exclude these consequences. The effects on welfare embrace every category of effect described in the Clean Air Act's definition of ''welfare'' and, more broadly, virtually every facet of the living world around us. And, according to the scientific evidence relied upon in making this finding, the probability of the consequences is shown to range from likely to virtually certain to occur. This is not a close case in which the magnitude of the harm is small and the probability great, or the magnitude large and the probability small. In both magnitude and probability, climate change is an enormous problem. The greenhouse gases that are responsible for it endanger public health and welfare within the meaning of the Clean Air Act.

74 Fed. Reg. 18886, 18898-904 (April 24, 2009).

The IPCC found that total GHG emissions have grown since pre-industrial times, with an increase of 70% between 1970 and 2004.[1] Of primary concern is Carbon Dioxide ("CO_2"), which is emitted in much larger quantities than any of the other greenhouse gases and is responsible for close to 85% of the total U.S. GHG inventory.[2] CO_2 emissions have grown between 1970 and 2004 by about 80% (28% between 1990 and 2004).[3] In 2006, U.S. fossil fuel combustion produced 5,637.9 metric tons of carbon dioxide, and emissions from coal alone used in electricity generation accounted for over 2,000 million metric tons

[1] IPCC Working Group III, Climate Change 2007: Mitigation, Summary for Policy Makers ("IPCC Working Group III Report") at ES-3, attached as Sierra Club **Exhibit 7**.

[2] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006, EPA #430-R-08-005, April 2008, ("EPA Inventory 1990-2006") at ES-4, Figure ES-4, attached as Sierra Club **Exhibit 8**.

[3] IPCC Working Group III Report (Ex 7) at ES-3.

of CO_2 in 2006. [4] Indeed, coal is the largest contributor to anthropogenic CO_2 increases into the atmosphere.[5]

B. BACT Limits for CO_2 Are Required at the MGP Facility Because CO_2 Is Subject To Regulation Under The Clean Air Act.

The proposed boilers at the MGP facility will emit hundreds of thousands of tons of CO_2 emissions each year. *See* Responsiveness Summary (Ex 4) at 34 (plant would burn 200,000 tons of Illinois coal every year); **AP 42, Fifth Edition** *Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources* § 1.1, Table 1.1-20[6] ("AP 42") (emissions from bituminous coal combustion of 5510 to 6250 lb CO2/ ton of coal) (200,000 tons coal/year * 5510-6250 lb CO2/ton coal = 551,000- 625,000 tons of CO2/year). Projecting a typical boiler life of 30 years, this equates to over 15 million tons of CO_2 over the boiler's life.

The Clean Air Act prohibits the construction of a new major stationary source of air pollutants except in accordance with a prevention of significant deterioration ("PSD") construction permit, which in turn requires the permitting agency to conduct a BACT analysis and include in the PSD permit a BACT emission limitation "for each pollutant subject to regulation [under the Clean Air Act] emitted from or which results from" the

[4] EPA Inventory 1990-2006 (Ex 8) at ES-5, 7, at A-3. This report expresses these figures as teragrams of CO2 equivalent (TgCO2). One teragram is equal to one million metric tons.

[5] "Dr. James E. Hansen Direct Testimony," *In re Interstate Power and Light Company*, before the Iowa Utilities Board, Docket No. GCU-07-01, at 3("Hansen Testimony"), attached as Sierra Club's **Exhibit 9**. Mr. Hansen is Director of the Goddard Institute for Space Studies. A trained physicist and astronomer, Mr. Hansen has focused on climate and global change for about twenty-five years.

[6] Available at http://www.epa.gov/ttn/chief/ap42/ch01/index.html, last visited July 9, 2009.

facility. 42 U.S.C. §7475(a), (a)(4), 7479(3). One of IEPA's fundamental failures in issuing the MGP permit is its failure to evaluate and impose a BACT limit on CO_2 emissions.

1. Sierra Club's Comments Preserved The Issue of CO_2 BACT Limits For Review In This Case.

In its public comments to IEPA, Sierra Club noted that:

> The Clean Air Act prohibits the construction of a new major stationary source of air pollutants in areas designated as in attainment of the National Ambient Air Quality Standards except in accordance with a prevention of significant deterioration ("PSD") construction permit. 42 U.S.C. § 7475(a); 40 C.F.R. § 52.21(a)(2)(iii). One of the requirements, contained in Section 165 of the Act, is that every PSD permit must include a BACT emission limit "for each pollutant subject to regulation under this chapter emitted from, or which results from" the facility. 42 U.S.C. § 7475(a)(4). EPA repeated that requirement in the implementing regulations controlling here: BACT is required for "any pollutant that otherwise is subject to regulation under the Act." 40 C.F.R. § 52.21(b)(50)(iv). CO_2 and N_2O are subject to regulation under the Act, but the Draft Permit contains no BACT limits for these pollutants.

Sierra Club Comments (Ex 2) at 8-9. Further, Sierra Club noted that:

- CO_2 is regulated through section 821 of the Clean Air Act Amendments of 1990, 42 U.S.C. §§ 7651k, note;
- The CO_2 regulations issued pursuant to section 821 are enforceable through the Clean Air Act, 42 U.S.C. § 7651k(e);
- EPA promulgated the monitoring and reporting requirements in 40 C.F.R. part 75, including those addressing CO_2, as regulations pursuant to the Clean Air Act;
- IEPA and other states have included CO_2 requirements as "applicable requirements" in Title V permits;
- EPA approved the Delaware Regulation 1144, limiting CO_2 emissions, into the Delaware State Implementation Plan pursuant to the Clean Air Act; and

- EPA regulates CO_2 under the Clean Air Act through the New Source Performance Standards (NSPS) for landfills pursuant to section 111 of the Act.

Id. at 9-15. These comments preserved this issue for review by the Board. 40 C.F.R. §§ 124.13, 124.19(a). In fact, these comments were more specific than those submitted by Sierra Club regarding the Deseret Power Cooperative permit, for which the Board granted review. *In re Deseret Power Elec. Coop.*, PSD Appeal No. 07-03, Petition for Review, Exhibit 2 (EAB, Nov. 21, 2007)[7]; *In re Deseret Power Elec. Coop.*, PSD Appeal No. 07-03, Order Granting Review (EAB, Nov. 21, 2007). The Board has jurisdiction to determine whether IEPA erroneously excluded BACT limits for CO_2 in this case.

2. IEPA's Response to Comments Concluded CO_2 BACT Limits Were Not Required for MGP.

In its response to public comments, IEPA takes the position that CO_2 is not a pollutant subject to regulation under the Clean Air Act and that, therefore, no BACT limit is required. For this position, IEPA relies entirely upon a memorandum dated December 18, 2008, after the close of public comment for the MGP permit, by former EPA Administrator Stephen Johnson (the "Johnson Memo"). *See* Responsiveness Summary (Ex 4) at 36-42. IEPA's position is unsupportable: the Johnson Memo fails to support IEPA's position, is conclusory in its analysis, which has since been discredited by EPA itself, and was issued *ultra vires*, purporting to change the agency's legislative rules, and this Board's

[7] Available at http://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/Filings%20By%20Appeal%20Number/D3D96202AB21FA76852574B20048DFB6?OpenDocument, last visited July 15, 2009.

final decision, without the requisite notice and comment rulemaking.[8] The Johnson Memo and IEPA's interpretations of it are discussed in further detail below.

3. The Board's Prior Decisions Have Discussed BACT Limits for CO_2.

Before discussing the errors in IEPA's analysis of CO_2 BACT requirements, it is helpful to review the recent history of this issue. The Board has considered four petitions raising CO_2 BACT, addressing the substance of the issue in two and denying review for failure to preserve the issue through public comments in the other two cases. *See In re Christian County Generation, LLC*, 13 E.A.D. __, PSD Appeal No. 07-01, Slip Op. 13-19 (EAB January 28, 2008) (finding that petitioner did not preserve this issue through sufficiently specific public comments); *In re Conocophilips Co.*, 13 E.A.D. __, PSD Appeal No. 07-02, Slip Op. at 44-52 (EAB June 2, 2008) (same); *In re Deseret Power Electric Cooperative*, 14 E.A.D. __, PSD Appeal No. 07-03 (EAB Nov. 13, 2008) (addressing merits of parties' arguments regarding EPA's historic interpretations and requirement of BACT for CO_2) ("Deseret"); *In re Northern Michigan University Ripley Heating Plant*, 14 E.A.D. __, PSD Appeal No. 08-02, Slip Op. at 31-32 (EAB February 18, 2009) (remanding permit based on reasoning set forth in *Deseret* decision) ("Northern Michigan").

In the recent *Deseret* case, the Board held that the EPA Region's refusal to include a BACT limit for CO_2 could not be sustained on the record that the Region had developed. Slip Op. at 6, 53. Specifically, the Board rejected the Region's argument that "EPA has

[8] It is also obvious that IEPA had prejudged this issue. Prior to the close of public comments and five months before the Johnson Memo, IEPA's air permit section construction permit manager asserted that "[a]t this point carbon dioxide is not a regulated pollutant under the Clean Air Act." Hr'g Tr. (Ex 3) at 28.

historically interpreted the term 'subject to regulation under the Act' to describe pollutants that are presently subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant." Slip Op. at 9. Instead, the Board held, the permitting authority (the Region) "is not constrained in this manner by an authoritative historical Agency interpretation." *Id*.

The Board's *Deseret* decision did not hold that the Clean Air Act requires a BACT limit for CO_2. *Id*. Instead, it found the Region's argument persuasive that the phrase "subject to regulation," in 42 U.S.C. § 7475(a)(4), is sufficiently ambiguous to require neither an interpretation that requires a pollutant to be subject to "actual control," nor an interpretation that finds monitoring and reporting to be "regulation." *Id*. at 29, 32-33 ("While it may mean 'subject to *a* regulation' as Sierra Club argues, the statute by its terms does not foreclose the narrower meaning suggested by the Region and Deseret, 'subject to control' (by virtue of a regulation or otherwise)." (emphasis original)).

It is important to note that the Board in *Deseret* was specifically addressing the petitioner's arguments that section 821 of the 1990 Clean Air Act Amendments, and EPA's implementing regulations in part 75, rendered CO_2 "subject to regulation under" the Act for purposes of establishing BACT limits under 42 U.S.C. § 7475(a)(4). The Board rejected the Region's claim, based on alleged prior EPA practice, that "subject to regulation" excluded the regulation of CO_2 under these provisions and instead meant "'subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant' (or any other clearly worded statement expressly connecting the meaning of the statutory phrase to 'actual control of emissions')"; the Board thus remanded the permit as lacking a sufficient basis in the record. *Id*. at 35-36, 53.

The *Deseret* decision did not address whether regulatory provisions, other than section 821 and its implementing regulations in 40 C.F.R. part 75, made CO_2 "subject to regulation under" the Act. *Id*. at 26 (summarizing petitioners' argument that CO_2 is regulated through section 821 and part 75), 32 ("Here, the parties contest whether section 821 of the 1990 Public Law must be viewed as part of the CAA and whether the terms of section 821 compel a particular meaning of the phrase "subject to regulation" for purposes of implementing sections 165 and 169."). Specifically, the Board did not decide whether landfill gas regulations, State Implementation Plan regulations, and other regulations adopted pursuant to the Act, and which limit emissions of CO_2, make CO_2 "subject to regulation" under the Act. *See, e.g., Id*. at 18 (noting that the Board struck portions of the petitioners' reply brief related to landfill gas regulations promulgated under section 111 of the Act).

The Board's *Deseret* decision also held that the 1978 PSD rulemaking provided the only definitive agency interpretation of the phrase "subject to regulation." *Id.* at 39. In that rulemaking, EPA "expressly states that it 'made final' an 'interpretation' the Administrator concluded was correct" for the meaning of "subject to regulation." *Id*. The EPA interpreted "subject to regulation" to mean any pollutant regulated in "Subchapter C of Title 40 of the Code of Federal Regulations for any source type." *Id*. at 38 (quoting 43

Fed. Reg. 26,388, 26,397 (June 19, 1978))[9]. As the Board found, this was a definitive agency interpretation "possess[ing] the hallmarks of an Agency interpretation that courts would find worthy of deference," such as published notice of the proposed interpretation in the Federal Register prior to publishing a final interpretation, that it represented considered judgment by the Administrator, and that it was issued "relatively contemporaneous with the statutory enactment and along with the original regulations implementing the statute." *Id*. at 39. EPA has not changed this interpretation through later rulemakings. *Id*. at 42-49. Moreover, the Board warned that guidance memos cannot change EPA's 1978 interpretation of the phrase "subject to regulation under the Act" in 42 U.S.C. § 7475(a)(4) and 40 C.F.R. § 52.21(b)(50)-- as including any pollutant regulated in 40 C.F.R. Chapter I, Subchapter C-- without likely running afoul of the court cases prohibiting revisions of agency interpretations without notice and comment. *Id*. at 52 (citing *Farmers Tel. Co., v. FCC*, 184 F.3d 1241, 1250 (10th Cir. 1999); *Alaska Prof'l Hunters Ass'n v. FAA*, 177 F.3d 1030, 1033-34 (D.C. Cir. 1999); *Paralyzed Veterans of Am. v. D.C. Arena L.P.*, 117 F.3d 579, 586 (D.C. Cir. 1997)).

Following the *Deseret* decision, the Board decided *Northern Michigan*, PSD Appeal No. 08-02. In that case, because the permitting agency's bases for not including a CO_2 BACT limit were similar to those relied upon by the permitting agency in *Deseret*, the Board remanded the permit to the agency "to undertake the same consideration" as set forth in the Board's *Deseret* decision, about "whether the CAA's pollutant subject to

[9] Title 40, Chapter I, Subchapter C of the Code of Federal Regulations includes parts 50 through 97.

regulation' language requires application of a BACT limit to CO_2 emissions." *Northern Michigan*, Slip Op. at 31. Additionally, because the *Northern Michigan* petition for review raised questions beyond those raised in *Deseret*, including whether regulation of CO_2 under the Clean Air Act through state implementation plans and through EPA's landfill gas regulations constitute "regulation under the Act," the Board instructed the agency to consider those issues as well. *Id*.[10]

4. **The Johnson Memo Attempted To Create A New Interpretation of "Subject to Regulation" To Mean "Subject to Control**."

In response to the Board's decision in *Deseret*, the outgoing EPA Administrator issued a memo purporting to interpret the phrase "subject to regulation under the Act." *See* Memorandum from Stephen Johnson to Regional Administrators, *EPA's Interpretation of Regulations that Determine Pollutants Covered By Federal Prevention of Significant Deterioration (PSD) Permit Program* (December 18, 2008) (hereinafter "Johnson" or "Johnson Memo"). The IEPA relied on the Johnson Memo for its response to comments in rejecting CO_2 BACT limits.

The Johnson Memo's central assertions were:

- The Board's decision in *Deseret* was "thorough, thoughtful, and based on the permitting record before the Board," and the Johnson memo is "not intended to supersede the Board's decision." Johnson at 2.

[10] The Board held that the issue of whether CO_2 is regulated under the Act through EPA's New Source Performance Standard under 42 U.S.C. § 7411 was not preserved for review through public comments, but ordered the permitting agency to consider it on remand because "the remand requires a fresh analysis of whether CO_2 and N_2O are 'subject to regulation.'" *Northern Michigan*, Slip Op. at 31-32.

- The phrase "subject to regulation under the Act" has never been interpreted by EPA before and, therefore, the memo "set[s] forth an initial interpretation of EPA's regulation at 40 C.F.R. § 52.21(b)(50)." *Id.*

- Through the Memo, EPA is adopting, for the first time, a definition of "regulation" meaning "control," rather than "a rule contained in a legal code." *Id.* at 7-8.

- Use of the word "otherwise" in 40 C.F.R. § 52.21(b)(50)(iv) means "the same type as," and invokes the rule of *ejusdem generis* so that "pollutants 'otherwise subject to regulation,' as used in the fourth part of [40 C.F.R. § 52.21(b)(50)], means pollutants that are subject to a promulgated regulation requiring actual control of a pollutant." *Id.* at 8 (citing *American Mining Congress* v. *EPA,* 824 F.2d 1 177, 1189 (D.C. Cir. 1987) (applying *ejusdem generis* to a statutory definition).).

- The Board's decision in *Deseret* expressly rejected the application of *ejusdem generis* due to lack of explanation, so "it then follows, with this additional analysis and statement of intent regarding the regulation, that the principle of *ejusdem generis* can be applied…." *Id.* at 8-9 (citing *Deseret*, Slip. Op. at 45-46).

- Policy factors favor subjecting a pollutant to BACT limits only after the Administrator or Congress has made a determination that a "particular pollutant[] should be subject to control or limitation," "on the basis of a considered judgment applying the applicable criteria in the Act," rather than a decision to collect information about a pollutant through monitoring. *Id.* at 9-10, 14; *see also id.* at 18 ("I believe that a pollutant should not become subject to mandatory emissions limitations under the PSD program until the Administrator (or Congress) has decided that such pollutants should be directly controlled by regulation.")

- Unidentified permits issued or reviewed by EPA have generally not included CO_2 BACT limits. Therefore, by omission, EPA has not interpretated monitoring and reporting requirements for CO_2 to constitute "regulation under the Act." *Id.* at 11.[11]

[11] The Johnson Memo also attributes to the Board an observation that "the 1998 memorandum… by the Agency's then General Counsel [Cannon] suggest[s] that the Agency has not, as a matter of practice, treated carbon dioxide as a "regulated" pollutant under any provisions of the Act, including those establishing the PSD program." *Id.* at 11 (citing *Deseret*, Slip Op. at 53-54). However, what the Board's *Deseret* decision at the cited pages actually states is that "[t]he Cannon Memo did not mention the PSD provisions at issue in this case," and that the Cannon memo, together with other memos and rule preambles, "are, at best, weak authorities upon which to anchor the Region's conclusion stated in its response to comments that its authority to require a CO_2 BACT limit is constrained by an historical Agency interpretation of CAA sections 165 and 169." *Deseret*, Slip Op. at 53-54.

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- The interpretation proposed in the memo is consistent with the 1978 preamble's definition of "subject to regulation" because that interpretation "said only that the PSD BACT requirement applies to 'any pollutant regulated in Subpart C of Title 40 of the Code of Federal Regulations,' but it did not amplify the meaning of the term 'regulated in.'" *Id*. at 12. Therefore, EPA is free to interpret "regulation" to mean "actual control," and to exclude monitoring and reporting while remaining consistent with the 1978 interpretation. *Id*. at 19.

- Because states cannot adopt regulations under the Act to apply in other states, EPA's approval and adoption of regulations into a State Implementation Plan do not make the pollutants controlled by such regulations "subject to regulation." *Id*. at 15 (citing *Connecticut v. EPA,* 656 F.2d 902, 909 (2d Cir. 1981).)

- Public notice and comment of the memo's interpretations is unnecessary because of expediency and to avoid "prolonged delay of permit reviews." *Id*. at 16. Additionally, because the memo is only meant to explain or clarify, and is not to give new meaning, it can be issued without notice and comment. *Id*. at 16 (citing *National Family Planning and Reproductive Health Assoc. v. Sullivan*, 979 F.2d 227, 236-37 (D.C. Cir. 1992).)

The Johnson Memo suffers from numerous procedural, legal, and logical problems, each of which is fatal to attempts to rely on the memo as IEPA did here.

5. The Johnson Memo Is Procedurally Defective and Was Therefore Void *Ab Initio*.

The Johnson Memo purports to "establish[] an interpretation clarifying the scope of the EPA regulation that determines the pollutants subject to" the PSD program. Johnson at 1. However, the memo goes far beyond mere interpretation of existing law. As the D.C. Circuit has explained:

> Interpretative rules "simply state[ ] what the administrative agency thinks the statute means, and only remind[ ] affected parties of existing duties." *General Motors Corp. v. Ruckelshaus,* 742 F.2d 1561, 1565 (D.C. Cir. 1984) (en banc) (internal quotation marks omitted). Interpretative rules may also construe substantive regulations. *See Syncor Internat'l Corp. v. Shalala,* 127 F.3d 90, 94 (D.C. Cir. 1997).

Assoc. of Amer. RR v. Dept. of Transp., 198 F.3d 944, 947 (D.C. Cir. 1999) (emphasis added). Here, the Johnson Memo characterizes itself as a mere interpretive rule, to avoid the procedural requirements – most importantly, public notice and comment – that would otherwise be imposed by the Clean Air Act and the Administrative Procedures Act, but then proceeds to announce a substantive rule.

That the Johnson Memo creates a substantive rule is evident in how it attempts to alter duties and obligations for future permitting, including establishing specific exceptions to its announced rule that "subject to regulation" means "subject to actual control," and by also asserting that pollutants subject to actual control under the Act through state implementation plans ("SIPs") are nevertheless not "subject to regulation." *See* Johnson Memo at 15.[12] The memo further attempts to create substantive duties for Regional Offices with regard to future SIP submittals (*Id*. at 3 n.1); for determining how pollutants become subject to PSD permitting in the future (*Id*. at 6 n.5); imposing requirements for instances when EPA makes a future regulatory endangerment finding (*Id*. at 14); and defining when and how import restrictions will trigger PSD for a pollutant. These are the types of "commands," "require[ment]s," "orders," or "dictates" that will affect the rights of parties in currently pending and future permitting actions. *Appalachian Power Co. v. EPA,* 208 F.3d 1015, 1023 (D.C. Cir. 2000).

[12] Interestingly, as the memo points out, EPA has adopted an interpretation preventing control of a pollutant (ammonia) in one state's SIP from making that pollutant "subject to regulation" for PSD, *see* Johnson Memo at 15-16 (regarding the treatment of ammonia as $PM_{2.5}$ precursors). The memo fails to recognized, however, that EPA did so – as required by law – through notice and comment rulemaking. *See* 70 Fed. Reg. 65984; 73 Fed. Reg. 28321.

The D.C. Circuit has made clear that agencies may not avoid procedural requirements such as notice and comment by this sort of semantic bait-and-switch:

> Although [our] verbal formulations vary somewhat, their underlying principle is the same: ***fidelity to the rulemaking requirements of the APA bars courts from permitting agencies to avoid those requirements by calling a substantive regulatory change an interpretative rule***.

U.S. Telecom Ass'n v. F.C.C., 400 F.3d 29, 35 (D.C. Cir. 2005) (emphasis added and citations omitted). Thus, prior similar attempts by agencies to create veiled substantive rules through guidance documents have being stricken, ignored, or rendered void by courts. *E.g., Alaska Professional Hunters*, 177 F.3d at 1034; *Paralyzed Veterans of Am.* 117 F.3d at 586; *see also Nat'l Family Planning & Reprod. Health Ass'n v. Sullivan*, 979 F.2d 227, 239 (D.C. Cir. 1992). The memo is owed no deference here.

6. The Johnson Memo Does Not Represent EPA's Final Position.

While the Johnson Memo may be disregarded as an improper substantive rule change, the current EPA Administrator has also called the Johnson Memo into doubt. On February 16, 2009, Administrator Jackson granted a petition for reconsideration of the Johnson Memo to reassess whether greenhouse gases are, in fact, already subject to regulation under the Clean Air Act. *See* Letter from Lisa Jackson to David Bookbinder (February 16, 2009), attached as Sierra Club's **Exhibit 10**. That grant of reconsideration went further, however, and warned "PSD permitting authorities" such as IEPA that they "should not assume that the memorandum is the final word on the appropriate interpretation of Clean Air Act requirements." *Id.*

The tenuous status of the Johnson Memo was reinforced when this Board decided *Northern Michigan* on February 18, 2009—two months after the Johnson Memo. There, the Board remanded a permit lacking CO_2 BACT to the permit agency with instructions to "fully consider" "whether approval by EPA of CO_2 or N_2O related provisions in several state implementation plans ("SIPs") constitutes CO_2 or N_2O regulation under the Act" and whether CO_2 is subject to regulation as a component of regulated landfill gases. *Northern Michigan*, Slip Op. at 31-32.

7. IEPA Erred In Determining that CO_2 Is Not Subject To Regulation Under the Act.

Here, the Board must determine whether CO_2 is subject to regulation under the existing definition of "subject to regulation under the Act." As Board has already noted, the existing definition resides in the 1978 rulemaking: "any pollutant regulated in 'Subchapter C of Title 40 of the Code of Federal Regulations for any source type.'" *Deseret*, Slip Op. at 38 (quoting 43 Fed. Reg. 26,388, 26,397 (June 19, 1978)). There is no question that CO_2 is subject to regulation in "Subchapter C of Title 40" of the C.F.R., which compels the conclusion that CO_2 is "subject to regulation" under either definition that the Board found reasonable in *Deseret*, *id*. at 32-33 ("subject to *a* regulation" versus "subject to control"). Therefore, there is also no question that a BACT limit for CO_2 is required before a valid PSD permit can issue in this case. 42 U.S.C. § 7475(a)(4); 40 C.F.R. § 52.21(b)(50)(iv).

a. CO_2 is the subject of regulations promulgated in Subchapter C of Title 40, and IEPA's decision to the contrary is in error.

As the Board is aware, Section 821 of the Clean Air Act Amendments of 1990 required EPA to promulgate regulations to require certain sources, including coal-fired electric generating stations, to monitor CO_2 emissions and report monitoring data to EPA. 42 U.S.C. § 7651k note. EPA promulgated those rules in 40 C.F.R. part 75, which is within Subchapter C of title 40. 40 C.F.R. §§ 75.1(b), 75.10(a)(3) (requiring monitoring of carbon dioxide emissions through installation, certification, operation, and maintenance of a continuous emission monitoring system or an alternative method), 75.33 (requiring preparation and maintenance of a monitoring plan), 75.57 and 75.60 – 64 (recordkeeping and reporting), and 75.5 (prohibiting operation except in compliance with Part 75). Furthermore, the operating permit program in part 71 and numerous State Implementation Plans in part 52—all within Subchapter C—incorporate the CO_2 monitoring and reporting requirements of Part 75. 40 C.F.R. § 71.2 (identifying CO_2 monitoring and reporting requirements in Part 75 as applicable Clean Air Act requirements that must be incorporated into Title V operating permits); Wis. Admin. Code § NR 439.095(1)(f) (Phase I and phase II acid rain units "shall be monitored for... carbon dioxide... "), adopted under the Act at 40 C.F.R. §§ 52.2570 (c)(73)(i)(l).

Moreover, through its Fiscal Year 2008 Consolidated Appropriations Act, Congress specifically required EPA to undertake rulemaking to establish monitoring and reporting requirements for all greenhouse gases (including CO_2), economy wide. H.R. 2764; Public Law 110–161, at 285 (enacted Dec. 26, 2007). Congress made clear that the agency is "to use its existing authority under the Clean Air Act" including "existing reporting requirements for electric generating units under section 821 of the Clean Air Act" in adopting these regulations. Conference Report for the Consolidated Appropriations Act, at 1254.[13] This action by Congress confirms that section 821 is part of the Clean Air Act and establishes a separate and distinct statutory obligation to regulate CO_2 through mandatory emission monitoring requirements under the Act. In fact, the EPA's regulatory obligations under the Appropriations Act are much broader than the agency's duties under section 821 as the Appropriations Act requires *economy wide* reporting.

Monitoring and reporting are "regulation." Indeed, the Supreme Court has considered such recordkeeping and reporting obligations to be regulation of protected First Amendment speech. *Buckley v. Valeo*, 424 U.S. 1, 66-68 (1976) (holding that record keeping and reporting requirements constitute regulation of political speech). Similarly, numerous court decisions recognize recordkeeping, reporting, and monitoring provisions as "regulation" in various subject areas. *See, e.g.*, *Dep't of Taxation v. Milhelm Attea & Bros.*, 512 U.S. 61 (1994) (examining agency regulations imposing recordkeeping requirements and quantity limitations on cigarette wholesalers selling untaxed cigarettes to reservation Indians); *Cal. Bankers Ass'n v. Shultz*, 416 U.S. 21 (1974) (reviewing Bank Secrecy Act of 1970's bank recordkeeping and reporting requirements); *Murray v. Northrop Grumman Info. Tech., Inc.*, 444 F.3d 169, 175 (2nd Cir. 2006) (noting "federal regulations" which require "monitor[ing] and report[ing]" for immigration purposes); *Appalacian Power Co. v. EPA*,

[13] Both the Appropriation Act and the Conference Report are available at: http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.

208 F.3d 1015, 1017 (D.C. Cir. 2000) ("Congress instructed EPA to pass regulations establishing the 'minimum elements of a permit program to be administered by any air pollution control agency,' including 'Monitoring and reporting requirements.'") (quoting 42 U.S.C. § 7661a(b)); *see also, e.g., id.* at 1027 (noting "test method and the frequency of testing for compliance with emission limitations are surely 'substantive' requirements"); *Painting & Drywall Work Preservation Fund v. Dep't of Housing and Urban Dev.*, 936 F.2d 1300, 1301 (D.C. Cir. 1991) (noting labor "regulations to monitor and enforce prevailing-wage laws"). CO_2 is therefore regulated under the Clean Air Act because monitoring and reporting requirements, enforceable by law through civil and criminal penalties, are "regulation," and in particular, are regulation within Subchapter C of title 40 of the C.F.R.[14]

IEPA's Responsiveness Summary asserts that IEPA did not include CO_2 BACT limits because:

> USEPA does not consider that the monitoring and reporting of CO2 emissions pursuant to Section 821 of the Clean Air Act Amendments of 1990 and certain provisions under 40 CFR Part 75 is sufficient for CO2 to be considered a regulated pollutant under the PSD program. This position is memorialized in a memorandum by Stephen Johnson, Administrator of the USEPA, dated December 18, 2008. .. As explained in the memorandum, for a pollutant to be considered subject to regulation under the Clean Air Act, a pollutant must be subject to requirements that control or limit emissions of the pollutant, not simply requirements related to the monitoring or reporting

[14] Sierra Club respectfully disagrees with the Board's decision in *Deseret* that the plain language of the Clean Air Act does not compel an interpretation that CO_2 is "subject to regulation" and Sierra Club preserves its rights to seek review of that interpretation. For purposes of preserving that issue for potential appeal, Sierra Club incorporates its briefs in the *Deseret* case and in the pending *Desert Rock Energy Company LLC* case, PSD Appeal No. 08-03, by reference.

> of emissions. The memorandum finds that the data gathering requirements for CO2 emissions promulgated under Title IV of the Clean Air Act does not compel the conclusion that Congress meant for CO2 to become a regulated pollutant under the PSD program.

See Responsiveness Summary (Ex 4) at 36. IEPA offers no analysis beyond reliance on the Johnson Memo. In fact, IEPA claims that it is bound to find that CO_2 is not regulated under the Act *because* of the memo. *Id*. ("Illinois EPA, as a permit authority that administers the federal PSD program in a delegated capacity, is obliged to implement USEPA's interpretation.").

Because the Johnson Memo was improperly issued and is being reconsidered, EPA does not have either a final or legally binding interpretation of "subject to regulation," and IEPA has not identified any. Contrary to the IEPA's implication that the Johnson Memo remains binding because Administrator Jackson's grant of reconsideration did not stay the memo's effectiveness (Responsiveness Summary at 36), the grant of reconsideration itself warned permitting agencies not to assume that the memo represents EPA's final position. Because EPA lacks a final official agency position, this Board must apply the most reasonable interpretation. That interpretation should recognize that obligations related to a pollutant, which are enforceable through administrative penalties and order, civil liability, and criminal sanctions, are regulation. Regardless, as set forth below, even if "subject to regulation" means "actual control," CO_2 meets that definition too.[15]

[15] IEPA also asserts in support of its refusal to apply CO_2 BACT limits that "the USEPA, under the leadership of Administrator Jackson, has begun a separate legal procedure whereby emissions of CO2

b. CO_2 is subject to "actual control" through multiple regulations found in Subchapter C, despite IEPA's and the Johnson Memo's claims to the contrary.

Even if "subject to regulation" is given a narrow interpretation meaning "subject to actual control," CO_2 meets the definition because it is subject to limits adopted under the Clean Air Act through rules located in 40 C.F.R. Ch. I, Subchapter C. As the Board noted in *Deseret*, the fact that CO_2 is regulated by rules contained in 40 C.F.R. Subchapter C "augers in favor" of a conclusion that CO_2 is "subject to regulation under the Act," based on EPA's official interpretation in its 1978 rulemaking. *Deseret*, Slip Op. at 41. In that case, the Board was looking at the monitoring and reporting requirements in 40 C.F.R. Part 75. The Board's reasoning, however, applies similarly to other regulations of CO_2 found in Parts 52 and 60.

i. The Delaware SIP includes "actual control" of CO2 and is included in Subchapter C.

CO_2 is subject to regulation under the Act through EPA's approval of amendments adding various CO_2 regulations to the SIP for the State of Delaware. 73 Fed. Reg. 23,101 (April 29, 2008); 40 C.F.R. § 52.420(c); *see also Deseret*, PSD Appeal No. 07-03, Letter from Brian L. Doster, U.S. EPA Office of General Counsel, to Erika Durr, EAB, Document # 93 (Sept. 9, 2008) ("…Office of General Counsel… believe that it is incumbent on them, in

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would be regulated under the Clean Air Act, by proposing to making a finding under Section 202 of the Clean Air Act that emissions of six greenhouse gases, including CO2, threaten the public health and welfare of current and future generations." Responsiveness Summary (Ex 4) at 36 (citing 74 Fed. Reg. 18886). While IEPA is correct that U.S. EPA has begun the process to make an endangerment finding for CO_2, this fact is irrelevant to whether CO_2 is currently subject to regulation under the Act. An endangerment finding is not a prerequisite to BACT limits.

recognition of a duty of candor, to inform the Board of a recent action by the Agency… EPA Region 3 issued a final approval of a Delaware State Implementation Plan (SIP) revision incorporating state regulations which include specific limitations on the rate of several pollutants, including carbon dioxide…"), attached as Sierra Club's **Exhibit 11**. Section 52.420(c) of Part 40 limits emissions of CO_2 in addition to establishing operating requirements, record keeping and reporting requirements, and CO_2 emissions certification, compliance, and enforcement obligations for new and existing stationary electric generators. 40 C.F.R. § 52.420(c) (adopting Del. Admin. Code 7 1000 1144 by reference). U.S. EPA's approval was made "in accordance with the Clean Air Act," 73 Fed. Reg. 23,101, and included the rule in Part 52.

The approved Delaware SIP limits emissions of CO2 from certain electric generators to the following rates:

Existing Distributed Generators	1,900 lbs/MWh
New Distributed Generators	1,900 lbs/MWh (if installed between effective date and 1/1/2012) 1,650 lbs/MWh (if installed on or after 1/1/2012)
New Distributed Generators that use Waste, landfill or digester gases	1,900 lbs/MWh

Delaware Department of Natural Resources and Environmental Control, Division of Air and Waste Management, Air Quality Management Section, Regulation No. 1144 § 3.2.1 – 3.2.2. (attached with Ex. 11). The regulated generators must certify compliance with the

CO_2 emission limits, monitor, and keep records. *Id*. at §§ 4.0, 6.0, 7.0. In short, CO_2 is subject to actual control under Delaware Regulation 1144.

Delaware Regulation 1144 is "under the Act." Delaware submitted Regulation 1144, including the CO2 emission limits contained therein, for EPA approval on November 1, 2007. 73 Fed. Reg. 11845, 11846 (March 5, 2008). EPA determined that the submission satisfied the requirements under CAA § 110(a), and published notice of its approval of the SIP revision in the Federal Register on March 5, 2008. 73 Fed. Reg. 11845. EPA allowed for public comment and, on April 29, 2008, EPA published notice of its Final Rule approving the SIP revision, effective May 29, 2008, in the Federal Register. 73 Fed. Reg. 23101 (April 29, 2008). Both the proposed and final rule notices state that EPA's approval of Delaware's Regulation 1144 was "under" and "in accordance with the Clean Air Act." 73 Fed. Reg. at 11845; 73 Fed. Reg. at 23101.

Pursuant to the Clean Air Act, states must adopt plans for regulating air pollution and, after notice and public hearings, submit those plans to EPA for approval. 42 U.S.C. § 110(a)(1). "To gain EPA approval, a 'state implementation plan' (SIP) must "include enforceable emission limitations and other control, measures, means, or techniques . . . as may be necessary to meet the applicable [CAA] requirements." *Alaska Dept. of Envtl. Protection v. EPA* 540 U.S. at 470 (quoting 42 U.S.C. § 7410(a)(2)(A)). EPA approves SIP revisions only where they meet the substantive requirements of Section 110(a)(2) of the Act, 42 U.S.C. § 7410(a)(2). *General Motors Corp. v. United States*, 496 U.S. 530, 537 (1990). The consequence of EPA approval makes the plan's requirements enforceable Clean Air

Act requirements. 42 U.S.C. §§ 7413(a)(1), (2), (b), 7602(q), 7604(a)(1) (providing citizens the right to enforce any "emission standard or limitation"), 7604(f)(3), (4) (defining "emission standard or limitation" to include "any condition or requirement under an applicable implementation plan relating to… air quality maintenance program" and "any other standard, limitation, or schedule established under… any applicable State implementation plan approved by the Administrator…"); *General Motors Corp.*, 496 U.S. at 540 ("the language of the Clean Air Act plainly states that EPA may bring an action for penalties or injunctive relief whenever a person is in violation of any requirement of an applicable implementation plan. § 113(b)(2), 42 U.S.C. § 7413(b)(2) (1982 ed.)."); *see also El Comite Para El Bienestar de Earlimart v. Warmerdam*, 539 F.3d 1062, 1066 (9th Cir. 2008); *Espinosa v. Roswell Tower, Inc.*, 32 F.3d 491, 492 (10th Cir. 1994); *Her Majesty the Queen in Right of the Province of Ontario v. City of Detroit*, 874 F.2d 332, 335 (6th Cir. 1989).

In adopting Delaware Regulation 1144 into Subchapter C, EPA was clear that it was adopting limits on CO_2 emissions under the Clean Air Act:

> Regulation No. 1144 contains provisions to control the emissions of nitrogen oxides (NOx), nonmethane hydrocarbons (NMHC), particulate matter (PM), sulfur dioxide (SO2), carbon monoxide (CO), *and carbon dioxide (CO2)* from stationary generators in the State of Delaware.
>
> Regulation No. 1144 establishes emission standards in pounds per megawatt-hour (lbs/MWh) of electricity output under full load design conditions or at the total load conditions specified by the applicable testing methods.
>
> …
>
> **CONCLUSIONS AND RECOMMENDED AGENCY ACTION:**

> Regulation No. 1144 adopted by the State of Delaware will result in the control of NOx, NMHC, PM, SO2, CO*, and CO2 emissions from stationary generators* and will help the State in attaining compliance with the 8-hour ozone NAAQS. EPA approval of the SIP revision is recommended.

Memorandum from Rose Quinto, Environmental Engineer Air Quality Planning Branch, U.S. EPA Region 3, Re: Technical Support Document - Delaware; Regulation No. 1144 – Control of Stationary Generator Emissions (January 25, 2008) (emphasis added), attached as Sierra Club's **Exhibit 12**.[16]

IEPA, again relying entirely on the Johnson Memo, determined that CO_2 is not subject to regulation through the EPA-approved Delaware SIP because:

> [The Johnson Memo] recognizes differences between SIP regulations under the Clean Air Act, which derive from principles of cooperative federalism, and national regulations, which generally apply in all states and are developed through USEPA rulemaking. Based on this distinction, USEPA does not consider pollutants that are only regulated by individual state SIPs to be pollutants subject to regulation under the Clean Air Act for purposes of the PSD program.

Responsiveness Summary (Ex 4) at 38. To the extent the Johnson Memo supports this assertion by IEPA, it does not support it with law or even logical analysis. Setting aside its *ipse dixit* conclusions, the central point to the Johnson Memo would actually support a finding that CO_2 is subject to BACT limits. The Johnson Memo is explicit that it was proposing an interpretation of "subject to regulation" that means "subject to actual control." Johnson at 7-8. As shown above, the Delaware SIP subjects CO_2 emissions to

[16] This memorandum in support of EPA's decision and part of EPA's rulemaking docket for the Delaware SIP revision and makes clear that EPA's approval of the Delaware CO_2 limits was not "inadvertent," as IEPA suggests. *See* Responsiveness Summary (Ex 4) at 39 (asserting that approval was inadvertent).

"actual control." Regarding the so-called "federalism" issue, the memo contains a side comment that "EPA does not interpret section 52.21(b)(50) to require regulation of that pollutant under the PSD program nationally or in other states that have not determined the need to regulate that pollutant to protect the NAAQS in that other state." *Id*. at 15. However, this self-serving statement is not fully explained and not logically connected to the premise of the proposed interpretation because SIP emission limits are, unquestionably, "actual control." In fact, by its own words, it concedes that the Delaware SIP is a "regulation of" CO_2, and that it was "approved by EPA" pursuant to the Clean Air Act. There is simply no basis for the conclusion that, somehow, such regulation under the Act is still not sufficient for purposes of PSD permitting. The apparent attempt in the memo to support this comment falls flat.

The Johnson Memo cites a single, inapposite, case: *Connecticut v. EPA,* 656 F.2d 902, 909 (2d Cir. 1981). *Connecticut* addressed whether EPA was required under 42 U.S.C. § 7410(a)(2)(E) (1977)[17] to deny a SIP revision for two power plants in New York, based on the fact that Connecticut and New Jersey have more stringent state standards that apply in their own states. The *Connecticut* court's decision was limited to interpreting the language of 42 U.S.C. § 7410(a)(2)(E), which prohibited emissions that "prevent maintenance of *national* primary or secondary ambient air quality standard," and held that the language of the statute refers to national standards and not state-specific standards. *Id*. at 909.

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[17] *See* section 110(a)(2)(D), 42 U.S.C. § 7410(a)(2)(D), in the current version of the Act.

Unlike the statue at issue in *Connecticut*, section 165(a)(4), 42 U.S.C. § 7475(a)(4), and 40 C.F.R. §§ 52.21(b)(50)(iv) and (j)(2) in this case contain no qualification that each pollutant must be subject to regulation "in the implementation plan for the state in which the source is to be located," "applicable nationally," or any other similar qualification.[18] Rather, the plain language of the statue and regulations require a BACT limit for *any* pollutant subject to regulation under the Act. As the D.C. Circuit reasoned in *Alabama Power Company v. Costle*: BACT applies "immediately to each type of pollutant regulated *for any purpose under any provision of the Act*." 636 F.2d 323, 403 (D.C. Cir. 1979) (emphasis added). Indeed, the *Alabama Power* court specifically rejected the idea that BACT applies only to a subset of pollutants subject to regulation in the various places throughout the Act:

> The only administrative task apparently reserved to the Agency . . . is to identify those . . . pollutants subject to regulation under the Act which are thereby comprehended by the statute. The language of the Act does not limit the applicability of PSD only to one or several of the pollutants regulated under the Act . . . .

Id. at 404. In short, the Johnson Memo's base interpretation results in a finding that CO_2 is subject to regulation because it is subject to "actual control," and the *non sequitur*

[18] The Johnson Memo is not even clear how many states, or air control districts, would have to limit emissions of a pollutant before it is subject to regulation in a sufficient number of states to be sufficiently "regulated under the Act" to count for PSD permitting (i.e., two, twenty-six, all fifty). Neither it, nor the language of the Act, supports IEPA's conclusory statement that "even if USEPA inadvertently created a pollutant for purposes of PSD, this action would be restricted to the State of Delaware, as it occurred in the context of approval of Delaware's SIP." Responsiveness Summary (Ex 4) at 39.

conclusion to the opposite in the memo has no legal or logical basis. It cannot support IEPA's refusal to include CO_2 BACT limits in the permit.[19]

ii. CO_2 is subject to "actual control" as one of the landfill gases limited by the New Source Performance Standards located in Subchapter C.

EPA also promulgated emission standards for municipal solid waste (MSW) landfill emissions in Subchapter C. 40 C.F.R. §§ 60.33c, 60.752. "MSW landfill emissions" are defined as "gas generated by the decomposition of organic waste deposited in an MSW landfill or derived from the evolution of organic compounds in the waste." 40 C.F.R. § 60.751. EPA has specifically identified CO_2 as one of the components of the regulated "MSW landfill emissions." *See* Air Emissions from Municipal Solid Waste Landfills – Background Information for Final Standards and Guidelines, U.S. EPA, EPA-453/R-94-021 (Dec. 1995) (explaining "MSW landfill emissions, or [landfill gas], is composed of methane, CO_2, and NMOC.").[20] Thus, CO_2 is regulated through the landfill emission regulations at 40 C.F.R. Part 60 Subparts Cc, WWW. *See also* 56 Fed. Reg. 24468 (May 30, 1991) ("Today's notice designates air emissions from MSW landfills, hereafter referred to as 'MSW landfill emissions,' as the air pollutant to be controlled").

IEPA asserts that because the landfill emission regulations do not set a specific emission rate for CO_2, that CO_2 is therefore not regulated by the NSPS standards.

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[19] Ironically, IEPA argues that EPA's approval of the Delaware SIP should not count because the public notice was not sufficient, in IEPA's view, to give the public an opportunity to comment. Responsiveness Summary at 39 and n.85. Instead, IEPA would rely entirely on the Johnson Memo that included *no* public comment period *at all*.

[20] *Available at* http://www.epa.gov/ttn/atw/landfill/landflpg.html.

Responsiveness Summary (Ex 4) at 41. This response confuses emission rate limits for individual pollutants with regulation of those pollutants under the Act. EPA has never said that a pollutant must be subject to an emission rate limit specific to that pollutant to be regulated under the Act. The NSPS standard for landfill gases includes various requirements intended to reduce emissions of landfill gases, including CO_2. EPA has argued previously that reduction and prevention, through enforceable steps, is "regulation"—even absent an emission rate limit. *See e.g., Deseret*, Slip Op. at n.27 (citing the Region's briefs, which argued that "regulation under the Act" "would apply the control of ozone depleting substances through production or import restrictions that do not limit the quantity, rate, or concentration of emissions."). Moreover, EPA and state regulatory agencies often regulate numerous pollutants—such as volatile organic compounds ("VOCs")—by reference to them categorically, rather than listing each separately. No one reasonably argues, however, that the individual VOCs are not regulated.

Furthermore, it is not true that greenhouse gas emissions-- including CO_2—are merely incidental to controlling "organic compounds and hazardous air pollutants." While it is true that the NSPS Rule was designed, in part, to control emissions of the trace amounts of non-methane organic compounds in the gas, that was not the only reason, and not the reason for including greenhouse gases in the regulation. In fact, there is little doubt that EPA intended to control greenhouse gases, including methane and carbon dioxide, through the NSPS for landfills.

Therefore, when EPA issued its final rule requiring control of landfill gas emissions—consisting almost entirely of two greenhouse gases, including CO_2, and only traces of other compound—it was doing so based on the agency's determination that the emissions "contribute[] to global climate change." In fact, based on quantities of gas, the rule can best be described as a limit on CO_2 and methane and secondarily a limit on other constituents of landfill gas. Landfill gas emissions contain approximately 50% methane, 50% carbon dioxide, and less than 1% non-methane organic compounds.

In a background technical document for that regulatory process, EPA, as early as March 1991, acknowledged that air emissions of greenhouse gases, including carbon dioxide and methane "contribut[ed] to the phenomenon of global warming," and that the "global warming effects" of those emissions posed "potential adverse health and welfare effects." *See* Sierra Club's Exhibit 13 at 2-15. EPA noted that while, at the time, there was uncertainty as to the timing and ultimate magnitude of global warming, there was already a "strong scientific agreement" that the increasing emissions of greenhouse gases "will lead to temperature increases" and that efforts were underway to develop control options. One of the specific justifications that EPA articulated for adopting the Rule (particularly at the level of stringency chosen) was to limit emissions of methane to avoid global warming impacts. *See* 56 Fed. Reg. 24468, 24481 (March 12, 1996) ("[i]n considering which alternative to propose as BDT, EPA decided to consider both NMOC's and methane reductions"); 61 Fed. Reg. 9905, 9906 ("Briefly, specific health and welfare effects from [landfill gas] emissions are as follows . . . methane emissions . . . contribute to global climate change as a major greenhouse gas"); *id*. at 9914 (anticipated "methane reductions . . . are also an important part of the total carbon reductions identified under the Administration's 1993 Climate Change Action Plan"). EPA further noted in the preamble to the final rule that "[c]arbon dioxide is also an important greenhouse gas contributing to climate change," and quantified the benefits of the rule based on "equivalent reduction in CO_2." 56 Fed. Reg. at 24472 (stating that "1.1 to 2.0 billion trees would need to be planted . . .to achieve an equivalent reduction in CO_2 as achieved by today's proposal"). Clearly, then, global warming impacts of landfill gas emissions were central to the NSPS standards. While methane was discussed in more detail, it is clear that CO_2 was considered during the rulemaking: that it comprises half of landfill gas and that it is a leading cause of global warming. It would be inconsistent with these statements by EPA to interpret the rule limiting landfill gas emissions—consisting of 50% carbon dioxide and calculating the benefits of the rule in the amount of CO_2 reduced-- as anything other than a rule that requires "actual control" of CO_2.

CO_2 is subject to regulation under the Clean Air Act and, therefore, a BACT limit was required in the final permit for MGP. Because IEPA failed to include such a limit, its permit decision is clearly erroneous and a remand is appropriate.

II. IEPA's CONSIDERATION OF CLEAN FUELS IN THE BACT ANALYSIS WAS CLEARLY ERRONEOUS.

A PSD permit, like the one at issue here for MGP, must contain limits that represent BACT. 42 U.S.C. § 7475(a)(4). BACT is a limit, based on the maximum degree of reduction achievable through, among other options, pollution control devices, available cleaner processes, and clean fuels. 42 U.S.C. §§ 7475(a)(4), 7479(3); *accord* 40 C.F.R. § 52.21(b)(12) (similar regulatory definition of BACT). Clean fuels are central to this definition.

> In its brief list of BACT production processes, methods, systems, and techniques, Congress sounds one prominent note: fuels. CAA § 169(3), 42 U.S.C. § 7479(3). In addition to "fuel cleaning" and "treatment or innovative fuel combustion techniques," the remaining listed control is "clean fuels." *Id*. Congressional direction to permitting applicants and public officials is emphatic. In making [BACT] determinations, they are to give prominent consideration to fuels.

Northern Michigan, Slip. Op. at 17-18; see *also Inter-Power*, 5 E.A.D. at 134 (discussing the requirement to consider clean fuels in the BACT definition).

The Board and EPA have required BACT limits to be based on clean fuels that are available and cost effective, except in unusual cases where doing so would require a different "basic purpose" or "basic design" (but only to the extent those are "objectively discernable"), or would "fundamentally change" or "call into question [the facility's] existence."[21] *In re Prairie State Generating Co.*, 13 E.A.D. ___, PSD Appeal No. 05-05, Slip Op. at 29, 32 (EAB August 24, 2006); *In re Hibbing Taconite Co.*, 2 E.A.D. 833, 843 (Adm'r 1989); *see also Northern Michigan*, Slip Op. at 26-27. Therefore, consideration of cleaner fuel has not been required for a coal-fired power plant that is built specifically to burn a dedicated fuel supply at an adjacent mine. *Prairie State*, Slip Op. at 31-32 (holding that the

[21] A choice of fuels for mere cost savings is not a "basic design" or "basic purpose." *Prairie State*, Slip Op. at 30 n.23.

purpose, as determined by the permitting authority, was to develop a plant for "a specific reserve of 240 million tons of recoverable coal," and where the mine and the plant were included in a single permit). In contrast, where a taconite processing facility is not intended for a dedicated fuel supply, and where natural gas could be used to fire a kiln, natural gas must be considered as a clean fuel alternative to petroleum coke. *Hibbing Taconite,* 2 E.A.D. at 843. Likewise, where natural gas can be used as a fuel in a cogeneration boiler, its use must be considered in a BACT analysis. *Northern Michigan*, Slip Op. at 20 n.17. Furthermore, the Seventh Circuit held that the mere fact that some parts of a plant have to be changed to accommodate a clean fuel does not allow a permitting agency to ignore the clean fuel in a BACT analysis, "[o]therwise 'clean fuels' would be read out of the definition of" BACT. *Sierra Club v. EPA*, 499 F.3d 653, 656 (7th Cir. 2007). Thus, the Seventh Circuit cautions, the clean fuels provision of BACT requires consideration of switching from a dirty fuel to a clean fuel, unless it would mean giving up the entire purpose of the permitted source (i.e., a power plant built specifically to burn a dedicated fuel supply and located on the same property as that fuel supply). *Id*. at 657.

This case presents a typical situation: the plant is not built specifically for a dedicated fuel supply and could use a much cleaner fuel while still accomplishing is primary purpose of generating process steam. In fact, IEPA agrees that it must consider natural gas and lower-sulfur subbituminous (Powder River Basin) coal as clean fuels in the BACT analysis for the MGP boilers. However, in conducting this analysis, IEPA made several serious errors, each of which is discussed below.

A. Sierra Club Preserved The Issue of Considering Clean Fuels In Its Comments.

Before setting out the errors in IEPA's BACT analysis, Sierra Club first notes that its comments preserved the issue of clean fuels in BACT, generally, and consideration of natural gas and subbituminous coal specifically. Permit Comments (Ex 2) at 16-23. Sierra Club commented, *inter alia*, that:

- IEPA cannot satisfy the requirement to consider clean fuels by merely asserting that MGP made a "business decision" to switch from natural gas to coal. *Id*. at 17.
- Natural gas is available, cleaner, currently relied upon to produce steam at MGP, proposed to be used to produce steam at MGP until the solid fuel boiler is finished and when that boiler is off-line, and is used by other similar facilities. *Id*. at 17-19.
- To justify a limit less stringent than that achievable with natural gas, IEPA is required to undertake a more robust analysis of costs and determine that natural gas is not cost effective pursuant to the top-down BACT process. *Id*. at 19.
- To the extent that IEPA provided any cost-effectiveness information at all, it merely provided a one-sentence statement from the applicant that switching to natural gas would cost an additional $50,000 per ton of sulfur dioxide avoided. *Id*. at 19-20.
- There was insufficient information in the permit record for the prices of fuels (coal types and natural gas) that should be considered in a top-down analysis. *Id*. at 20.
- IEPA's decision not to base BACT limits on lower-sulfur coal was not supported by legitimate reasons, but by generalized statements about availability of coal nationally and generalized concerns about delivery of coal. *Id*. at 20-21.

B. IEPA's Response to Comments.

In its response to comments IEPA agrees with Sierra Club's comment that natural gas must be considered as a clean fuel in a top-down BACT analysis for an industrial steam boiler. IEPA notes that "[w]hile MGP would like to reduce its long-term energy costs, MGP has indicated that its basic objective for this project is to continue in operation. This will require a substantial capital investment to develop a new boiler facility to power its existing plant." Responsiveness Summary (Ex 4) at 4. In other words, as described by the applicant, the "basic" or "fundamental" purpose of the project at issue is to produce steam to replace the supply that it currently gets from the Ameren cogeneration plant. In fact, IEPA considered natural gas in the BACT analysis, but concluded that it was not cost effective for reducing SO_2 emissions. *Id*. at 16. Moreover, IEPA disclaimed the argument that considering natural gas as a clean fuel for the proposed plant would be impermissible, or would "redesign" the plant. *Id*. at 16 ("In fact… neither MGP nor the Illinois EPA made the argument that it would be inappropriate as part of the BACT analysis for the proposed project to consider the use of natural gas because it would "redefine the source."). As IEPA explained, considering natural gas would not be improper because it would not change the fundamental purpose of the project: to supply process steam (and potentially electricity) [22] for the mill and ethanol plant.

However, based on IEPA's cost analysis (which Sierra Club raises issue with below), IEPA rejected natural gas on cost-effectiveness grounds on assertion that the cost-per-ton to reduce SO_2 emissions by burning cleaner fuels would be too high.

[22] IEPA implies that MGP might forgo cogenerating electricity if it were to use natural gas instead of coal. IEPA suggests that this could be a redesign "from the ground up" and might be an impermissible "redefining the source." Responsiveness Summary (Ex 4) at 18 and n.27. Sierra Club disagrees with this assertion, which is not supported in the record or the law and is, in fact, contradicted by IEPA's next paragraph, which notes that it is possible to supply steam and power with natural gas. *Id*. ("a high-pressure boiler fired on natural gas could theoretically be substituted for the proposed solid fuel-fired boiler and meet MGP's objective for this project, i.e., development of a cogeneration facility to directly supply the steam and much of the electric power needed by its existing plant."). Because IEPA explicitly disclaims reliance upon a "redefining the source" argument to avoid considering natural gas in a BACT analysis for the plant, it is not necessary to raise as an issue in this case. *Id*. at 18 (asserting that IEPA is not claiming that natural gas cannot be considered as a clean fuel and that IEPA considered natural gas as a control option but concluded that it would not be cost effective).

> [T]he BACT determination for the proposed project considered use of natural gas as an alternative to use of coal in the primary, solid fuel-fired boiler. This is because a high-pressure boiler fired on natural gas could theoretically be substituted for the proposed solid fuel-fired boiler and meet MGP's objective for this project, i.e., development of a cogeneration facility to directly supply the steam and much of the electric power needed by its existing plant. As explained elsewhere, this approach to control of emissions from the proposed project was rejected because of excessive cost impacts, evaluated in terms of cost expended per ton of emissions that would be avoided.

Responsiveness Summary (Ex 4) at 18; *see also id*. at 19-20 (noting that IEPA and the applicant considered natural gas but concluded that the cost per ton of sulfur dioxide reduced would be greater than the $10,000 per ton threshold IEPA uses for cost effectiveness).

Therefore, Sierra Club agrees with IEPA that considering natural gas as a clean fuel is required in a BACT analysis, and that it does not impermissibly redefine the source. Sierra Club also agrees with the concept that *if* the cost per ton of using natural gas exceeds a range of costs considered "cost effective," according to a *legitimate cost-effectiveness analysis*, it can be rejected in step four of the top-down BACT process. *See* Office of Air Quality Planning & Standards, U.S. EPA, *New Source Review Workshop Manual* (draft Oct. 1990) at B.31-32 ("NSR Manual"); *see also Northern Michigan*, Slip Op. at 15 ("In the fourth step, energy, environmental, and economic impacts are considered and the top alternative is either confirmed as appropriate or is determined to be inappropriate. The cost effectiveness of the alternative technologies is considered under this step. Step four thus validates the suitability of the top control option identified or provides a clear justification as to why the top control option should not be selected as BACT." (internal cites omitted)). However, Sierra Club disputes, and therefore raises in this proceeding, the calculations IEPA performed in response to comments, the methods that IEPA employed, and the metrics IEPA used to conclude that clean fuels would not be cost-effective.

Regarding the other "clean" fuel at issue—lower sulfur coal (Powder River Basin or "PRB")—IEPA claims to have considered this cleaner fuel, but responded to comments that lower sulfur coal "would be a significantly more costly 'premium coal,' whose additional costs are not justified by the accompanying reduction in emissions." *See* Responsiveness Summary (Ex 4) at 29. IEPA made this determination, that PRB coal is not cost effective, based on IEAP's assumption that all plants burning PRB coal are set up to receive unit train shipments of coal. *Id*. at 29-30. Therefore, IEPA assumes an additional $4.8 million, per year, to ship PRB coal from a coal terminal to the MGP plant by truck. *Id*. IEPA offsets part of that cost, $1,183,600 per year, due to the lower operating costs when burning PRB coal. *Id*. at n.62 (calculating the additional cost for firing PRB to be $3,616,400 per year).

IEPA figures that using PRB coal at MGP would result in annual SO_2 emissions of 189.1 tons, compared to SO_2 emissions of 323.6 tons with the proposed Illinois high-sulfur coal. *Id*. at n.62. To reach a determination that PRB coal would not be cost-effective, IEPA divided the additional cost of PRB coal ($3,616,400) by the difference in sulfur emissions from Illinois coal and lower sulfur PRB coal (323.6 (IL coal) – 189.1 (PRB coal) = **134.5 tons**

SO2/year) to determine that the incremental[23] cost of using PRB coal to reduce SO_2 emissions would be greater than a $10,000 per ton, average cost-effectiveness threshold used by IEPA. *Id*.[24] Thus, IEPA claims that it rejected the use of lower sulfur (in this case, PRB) coal for cost-effectiveness reasons. *Id*. at 33.

As with natural gas, IEPA expressly denies rejecting low sulfur coal because it would "redefine the source" or because of a preference for local, Illinois, coal. *Id*. ("The use of such fuels was not rejected out of hand because it would 'redefine the source.' It also was not rejected because the economic policy of the State of Illinois is to support Illinois' coal mining industry as it provide jobs for individuals that work in this industry and is beneficial to the state's economy.")

Here too, Sierra Club agrees that low sulfur coal does not redefine the boiler. Sierra Club does disagree with the method, metric, and calculations IEPA used to make its determination that low sulfur coal is not cost effective.

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[23] This does not represent a true incremental cost effectiveness analysis, however, because it did not calculate the difference in total annual tons per year between the control options, as discussed below.

[24] IEPA did an additional assessment in response to comments, assuming that PRB costs $65 per ton, plus 25% additional cost to MGP over market rates, plus another 25% increase for MGP for transportation costs over other plants, plus another $20/ton charge for intermediate handling of coal (IEPA wanted to use $25.08 but MGP's true cost is only $20) resulting in a cost-effectiveness value for control of SO2 emissions of $43,500 per ton of emissions that is avoided. *See* Responsiveness Summary (Ex 4) at n.70. None of these cost inflators, except the $20 actual cost incurred by MGP, has any basis in the record. IEPA appears to have invented the 25% cost premium figure and applied it to the price of coal at the mine and the price of transportation.

C. Background on Cost Effectiveness Considerations In A Top-Down BACT Analysis.

Cost considerations in determining BACT are expressed in one of two ways: average cost effectiveness or incremental cost effectiveness. *NSR Manual* at B.36; *see also Inter-Power*, 5 E.A.D. at 136.

<u>Average Cost Effectiveness</u>. The first step in calculating the average cost effectiveness of alternative control options (such as coal plus scrubber vs. natural gas clean fuel), is for IEPA to correctly define the baseline emission rate. Baseline emission rates are "essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions," for the applicant's proposed fuel choice. *See NSR Manual* at B.37.[25] Once the baseline is calculated, the cost-per -ton of pollutant controlled is calculated for each control option by dividing the control option's annualized cost by the tons of pollution avoided ("Baseline emissions rate – Control option emission rate"). *In re Steel Dynamics*, 9 E.A.D. 165, 202 n.43 (EAB 1999); *In re Masonite Corp.*, 5 E.A.D. 551, 564 (EAB 1994); *NSR Manual* at B.36-.37.

<u>Incremental Cost Effectiveness</u>. Incremental cost effectiveness is an optional consideration that must always be paired with average cost effectiveness. *NSR Manual* at B.41 ("incremental 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

[25] "The NSPS/NESHAP requirements or the application of controls, including other controls necessary to comply with State or local air pollution regulations, are not considered in calculating the baseline emissions." *NSR Manual* at B.37.

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.

The use of incremental cost effectiveness is limited. It is only used to compare "dominant" alternative pollution control options. *NSR Manual* at B.43. This requires plotting all pollution control options to create an "envelope of least-cost alternatives" "depicted by the curvilinear line connecting" the control options. *NSR Manual* at B.41-.43 and Figure B-1. Incremental cost effectiveness is the difference in total annual costs between two contiguous control options that are on the dominant control curve. *Id*. The consideration of incremental cost effectiveness is not to be used to reject an option merely because it costs more—even if it costs twice as much—as the next dominant alternative. *Id*. at B.43.

<u>Determining Cost Effectiveness</u>. When determining if a pollution control option has sufficiently adverse economic impacts to justify rejection of that option and establishment of BACT on a less effective option, a permitting agency must determine that the cost-per-ton of emissions reduced is beyond "the cost borne by other sources of the same type in applying that control alternative." *NSR Manual* at B.44; *see also Steel Dynamics*, 9 E.A.D. at 202*; 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 original)).

In a cost-effectiveness determination, the cost of controlling air pollution with clean fuel at the permittee's source must be compared to the cost of controlling pollution <u>with the same clean</u> fuel at other facilities in the same source category. This consideration <u>does not</u> compare the cost-per-ton of air pollution with one pollution control option to the cost-per-ton of another pollution control option. For example, the cost-per-ton of controlling SO_2 with natural gas on the permittee's facility is compared to controlling SO_2 with natural gas at other facilities in the same category; the cost of controlling with natural gas is <u>not</u> compared to the cost-per-ton of controlling SO_2 with a scrubber. This is consistent with the rule for BACT analyses that the collateral impacts provision (including cost-effectiveness) "operates primarily as a safety valve whenever unusual circumstances *specific to the facility* make it appropriate to use less than the most effective technology." *In re Columbia Gulf Transmission Co.*, 2 E.A.D. 824, 827 (Adm'r 1989) (emphasis added).

In short, cost-effectiveness measures cost differences between facilities applying the same technology. A cost analysis that strays too far from this rule by creating and applying a default cost-per-ton threshold that applies across facilities, control technologies, and time, undermines the premise of the collateral impacts analysis.

In limited circumstances, an applicant can avoid BACT based on a pollution control option that does not have significantly higher costs than incurred at other facilities using the <u>same</u> control option. To do so, however, the source must document that:

(1) the "control alternative has not been required as BACT (or its application has been extremely limited)";

(2) "there is a clear demarcation between recent BACT control costs in that source category and the control costs for sources in that source category which have been driven by other constraining factors (e.g., need to meet a PSD increment or a NAAQS)"; and

(3) the "applicant… demonstrate[s] to the satisfaction of the permitting agency that costs of pollutant removal (e.g., dollars per total ton removed) for the control alternative are disproportionately high when compared to the cost of control for the pollutant in recent BACT determinations."

Only when all three of these criteria are met can a pollution control option be rejected as the basis for BACT without showing a significant difference in cost with other facilities using the same pollution control. *NSR Manual* at B.45; *see also Inter-Power*, 5 E.A.D. at 136 (discussing this secondary average cost-effectiveness consideration, where the control option has never or rarely been applied).

It is also important to note that a pollution control option must be outside the range of costs borne by facilities in the same source category, <u>plus the margin of error</u>, to be determined not cost effective. Cost calculations used in BACT determinations are only assumed to be accurate within 20 to 30 percent. Therefore, EPA's guidance concludes that this uncertainty is resolved in favor of defaulting to the most pollution control:

> Study cost estimates used in BACT are typically accurate to $\pm$ 20 to 30 percent. Therefore, control cost options which are within $\pm$ 20 to 30 percent of each other should generally be considered to be indistinguishable when comparing costs.

NSR Manual at B.44. Therefore, generally a pollution control option must be outside this margin, i.e., be more than 20-30% more expensive than other sources controlling air pollution for a control option to be eliminated in a top-down BACT analysis.

D. IEPA's Clean Fuels Analysis Improperly Rejected Clean Fuels Based on Incremental Cost Effectiveness and Failed to Properly Consider Average Cost Effectiveness.

As noted above, the central, first step in assessing cost effectiveness in a top-down BACT analysis is to determine the average cost effectiveness. This requires determining the baseline—which is generally the annual uncontrolled emissions of the project proposed by the applicant—and then dividing that value by the annualized cost of the pollution control (or combination of controls). That was not done here for clean fuels.

1. IEPA Improperly Relied Solely On Incremental Cost Effectiveness And Did Not Calculate The Average Cost Effectiveness For Use of Natural Gas.

The IEPA failed to conduct a proper cost-effectiveness analysis because it failed to calculate average cost effectiveness and relied, instead, wholly on incremental cost effectiveness. This incremental-cost-effectiveness-only analysis is clear error. *NSR Manual* at B.41 ("incremental 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.").

IEPA estimated the annual difference in the cost of using coal and natural gas as $34,000 per ton of SO_2, compared it to an average cost effectiveness threshold of

$10,000/ton, and concluded natural gas is not cost effective. This $34,000/ton figure[26] is based on the formula for incremental cost effectiveness in the *NSR Manual* at page B.41.[27] The incremental cost effectiveness is defined by the NSR Manual as:

$$= \frac{[\text{total annual cost of control option - total annual cost of next control option}]}{[\text{next control option emission rate - control option emission rate}]}$$

The numerator in this formula is the difference in the total annual cost[28] of two control options, here burning coal with a scrubber and burning gas without a scrubber. In this case, IEPA calculated incremental cost effectiveness using the difference in fuel prices when burning gas compared to coal ($25 MM)[29], less the difference in the capital and operating cost savings when burning gas compared to the higher costs of running a coal plant ($14 MM):

COAL CONTROL OPTION

cost of burning coal: $9.4 MM/yr[30]

additional capital and operating cost for coal: $14 MM/yr[31]

GAS CONTROL OPTION

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[26] Responsiveness Summary (Ex 4) at n. 32.

[27] Incremental cost effectiveness = [total annual cost of control option - total annual cost of next control option]/[next control option emission rate - control option emission rate] = [$25.7MM - $14MM]/[323.6 ton/yr] = $34,000/ton.

[28] Total annual cost is the sum of annualized capital cost plus annual operating and maintenance cost.

[29] IEPA reports the difference in the cost of burning gas and coal as $25,000,000. Our calculations, presented above, indicate that the difference is $25,700,000, based on the unit cost of coal and gas reported in the Responsiveness Summary, footnote 32.

[30] Based on IEPA's calculation of the cost of burning coal: ($2.17/MMBtu)(493 MMBtu/hr)(8760 hr/yr) = $9,371,536/yr.

[31] This value is not supported in the record available to us at the timing of this Petition.

cost of burning gas: \$35.1 MM/yr[32]

Based on these apparent calculations, IEPA determined a numerator for cost effectiveness of approximately: gas - coal = \$35.1 MM/yr - (\$9.4 MM/yr + \$14 MM/yr) **= \$11.7 MM/yr**[33]

The denominator that IEPA used in its cost-effectiveness analysis for natural gas was 323.6 tons per year.[34] IEPA did not provide the basis (calculation) for this number, but it appears to be the SO_2 emissions from the MGP boiler burning coal after the scrubber, from Table I of the Permit. In other words, IEPA's only calculation for cost effectiveness of using gas was the cost of the additional reduction in SO_2 beyond that estimated to be achieved from an SO_2 scrubber on a coal boiler ((\$25 MM - \$14MM)/323.7 = \$34,000/ton SO_2), which represents the incremental cost effectiveness.[35]

IEPA did not calculate the average cost effectiveness of using natural gas. As a result, IEPA's analysis presents the misleading scenario that the *NSR Manual* warns of: "undue focus on incremental cost effectiveness can give an impression that the cost of a

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[32] Based on IEPA's calculation of the cost of burning gas: (\$8.12/MMBtu)(493 MMBtu/hr)(8760 hr/yr) = \$35,067,682/yr.

[33] The IEPA incorrectly reported this as (\$25,000,000 - \$14,000,000) = \$11,000,000/yr (Responsiveness Summary, footnote 32), due to the error in fuel calculation discussed supra in footnote 29.

[34] The value that IEPA used for incremental tons of SO_2 removed is apparently the permitted annual SO_2 emissions from the coal option, based on Table I of the Permit, rather than incremental tons removed. IEPA should have used incremental tons reduced, which in this case is nearly equal to permitted tons as natural gas has very little sulfur. Incremental SO2 tons would be: 323.6 - (0.00059 lb/MMBtu)(493 MMBtu/hr)(8760 hr/yr)/2000 ton/yr = 323.6 - 1.3 = 322.3 ton/yr.

[35] We note there are a number of errors in IEPA's calculation. First, in footnote 32 to the Responsiveness Summary, IEPA reports the results of the calculation as \$22,000/ton, rather than \$34,000/ton. Second, the incremental cost is \$11.7 MM/yr, based on IEPA's stated assumptions, not \$11 MM/yr. Third, the SO2 *reductions* are 322.3 ton/yr (323.6 ton/yr – [0.00059 lb/MMBtu x 493 MMBtu/hr x 8760 hr/yr/2000 lb/ton]), not 323.6 ton/yr. Correcting these errors, the incremental cost effectiveness is: \$11.7 MM/yr/322.3 ton/yr = \$36,301/ton.

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." *NSR Manual* at B.45-.46. Failure to consider average cost effectiveness, alone, is clearly erroneous and requires a remand of the permit.

2. IEPA Incorrectly Compared An Incremental Cost Effectiveness Value to A Threshold For Average Cost Effectiveness.

In addition to relying only on incremental cost effectiveness, as noted above, IEPA erred by comparing an <u>incremental</u> cost effectiveness value (dollars per additional ton of SO_2 removed, beyond the reduction achieved with a scrubber on a coal boiler) to a $10,000 per ton threshold for <u>average</u> cost effectiveness for both PRB coal and natural gas. *See* Responsiveness Summary (Ex 4) at 20 ("For emissions of SO_2, cost-effectiveness values on the order of $10,000 per ton have commonly been considered sufficient to reject use of an alternative fuel as an approach to reduce SO2 emissions.")[36] This conflates two concepts—average cost effectiveness and incremental cost effectiveness. IEPA's failure to distinguish the two, and its application of an average cost effectiveness value to an incremental cost effectiveness calculation is clear error.

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[36] This statement is vague, but appears to be applying a default $10,000 per ton average cost effectiveness, since $10,000 per ton is approximately the value that other permitting decisions have used for average cost effectiveness. *See*, *e.g.*, 64 Fed. Reg. 26,004, 26,074 (May 13, 1999); EPA, Draft Regulatory Support Document at 7-12, *at* http://www.epa.gov/OMS/regs/nonroad/proposal/chptr-7.pdf; Memorandum from John S. Seitz, Director, OAQPS, to Air Division Directors re: "BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic Compounds at Tier 2/Gasoline Refinery Projects" at 3 (Jan. 19, 2001). *See also* San Joaquin Valley Air Pollution Control District, Update to Rule 2201 Best Available Control Technology (BACT) Cost Effectiveness Thresholds, Draft Staff Report (Jan. 24, 2008); *cf. Columbia Gulf*, 2 E.A.D. at 825 ($3,000 - 6,500/ton cost effective as of 1988. Converted to March 2009 dollars, this yields an average cost effectiveness range of $4,600 to $9,900/ton.). As noted above, it is inconsistent with the purpose of the collateral impacts analysis to apply a default cost-per-ton, rather than a comparison of the cost of control at the permittee's facility compared to the cost of that control at other facilities. Here, it is also wrong to compare a default average cost effectiveness value to a calculation for incremental cost effectiveness.

3. IEPA Did Not Compare The Average Cost Effectiveness of Burning Gas To The Cost Of Burning Gas At Other Sources.

As noted above, the central consideration in assessing cost-effectiveness is whether the cost of implementing a pollution control option at the permitted source is beyond "the cost borne by other sources of the same type in applying <u>that control alternative</u>." *NSR Manual* at B.44 (emphasis added); *see also Steel Dynamics*, 9 E.A.D. at 202; *Inter-Power*, 5 E.A.D. at 135. The *NSR Manual* also states that "where a <u>control technology</u> has been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant cost differences, if **any**, between the application of the <u>control technology</u> on those sources and the particular source under review." *NSR Manual* at B. 31 (bold emphasis original, other emphasis added). IEPA made no finding regarding the cost of the control technology (natural gas) at MGP and the cost of the same control technology at other sources. Therefore, to reject the use of clean fuel natural gas for cost-effectiveness reasons, IEPA would need to determine that using natural gas at the MGP boiler would be beyond the cost to similar facilities using natural gas. IEPA has not done so and, therefore, cannot properly reject natural gas as a clean fuel control alternative based on the record in this case.

Moreover, it is highly unlikely that IEPA could make any record to support rejecting clean fuel natural gas at MGP. The average cost effectiveness of burning gas would be essentially the same for any natural gas fired boiler, differing only by regional differences in the price of gas. Thus, the average cost effectiveness of natural gas at MGP would be comparable, if not lower, than that borne by other similar facilities firing gas. In fact, the cost would be no more than for MGP's proposed second boiler, which will be nearly the same size and will burn natural gas as the basis for BACT. *See* Project Summary (Ex 5) at 9 ("For the auxiliary boiler, good combustion practices and low-NOx burner technology are proposed as BACT for CO and NOx, and use of natural gas for SO2 and PM."). Therefore, the cost of natural gas as a clean fuel for the primary boiler proposed at MGP will be no more costly than for the secondary boiler at the same facility using natural gas as its pollution control. Presumably, if IEPA had looked to other facilities, the cost to MGP to burn gas would be the same as for other facilities too. IEPA has no basis to reject natural gas as not cost-effective. In fact, IEPA even admits that there are many similar boilers operating with natural gas,[37] indicating that natural gas is per se cost effective.

Moreover, IEPA made no findings that natural gas has "not been required as BACT (or its application has been extremely limited)," or that "there is a clear demarcation

[37] As to the natural gas fired boilers in fuel ethanol plants, IEPA argues that more steam is needed to produce a gallon of beverage alcohol than a gallon of fuel alcohol and thus steam costs are a larger factor in the cost of producing beverage ethanol. IEPA also argues that beverage and fuel ethanol plants operate in different markets. Responsiveness Summary (Ex 4) at 17 n.26. These arguments are irrelevant to cost effectiveness, which is a measure of cost per ton of pollutant removed compared to similar sources—not cost per ton of ethanol produced. The nature or volume of the ethanol produced is also irrelevant as to the design of the boiler and the control of pollutants: food ethanol, fuel ethanol, and many other industries use the same or similar boilers to make steam for producing products. At best, IEPA is arguing for consideration of the business climate and economics of the applicant's plant. This is outside the scope of the cost considerations that can be included in a BACT analysis. *NSR Manual* at B.31 ("primary consideration should be given to quantifying the cost of control and not the economic situation of the individual source.") Cost effectiveness is the cost to control a ton of pollution, independent of the economics on the underlying source. *NSR Manual*, at B.31. Moreover, the distinction is irrelevant here because MGP makes fuel ethanol. Mr. Steve Wilber, the applicant's project manager, testified at the public hearing that "MGP Ingredients is an ingredients company *that makes renewable fuels*, as well as wheat products." Hr'g Tr. (Ex 3) at 12 (emphasis added); *see also id*. at 14-15, 22. Many natural gas fired boilers at fuel ethanol plants have been permitted in the last 5 years.

between recent BACT control costs in that source category and the control costs for sources in that source category which have been driven by other constraining factors (e.g., need to meet a PSD increment or a NAAQS)." *NSR Manual* at B.45. Both of these prongs must be met before turning to an analysis of whether the "applicant… demonstrate[s] to the satisfaction of the permitting agency that costs of pollutant removal (e.g., dollars per total ton removed) for the control alternative are disproportionately high when compared to the cost of control for the pollutant in recent BACT determinations." *Id*. Therefore, in addition to failing to make a record that the cost of burning natural gas would be disproportionately high at MGP compared to other gas-fired sources, IEPA also failed to make a record for the secondary average cost-effectiveness consideration of whether the cost of burning natural gas to control emissions is disproportionate to the cost that other similar sources incur to control the same pollutants (albeit with different control options).

4. **The Average Cost Effectiveness of Using Clean Fuel Natural Gas Is Well Below The $10,000-per-ton Cost-Effective Threshold Used By IEPA.**

Even if IEPA could fulfill its prerequisite burden to compare the cost of burning natural gas at MGP to the cost at other facilities using the same pollution control option, and moved to the secondary consideration of comparing the cost of implementing a control option (natural gas) to the cost of controlling the same pollutant at other source (using different control options), *NSR Manual* at B.45, the average cost-effectiveness of using natural gas is well within the range of SO_2 controls uses elsewhere. As discussed above, average cost effectiveness is calculated from a baseline of no control. *See NSR Manual* at B.37 (stating that baseline emission rates are "essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions"). Here, no control is the emission rate from burning coal without add-on pollution controls. Using only SO_2, from the uncontrolled baseline emission rate of 7.0 lb SO2/MMBtu[38], the average cost effectiveness to burn natural gas considering only SO2 is $2,320/ton.[39, 40] The average cost effectiveness considering all criteria pollutants (see discussion below) is $1,514/ton.[41] This is well below the $10,000/ton default threshold for average cost-

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[38] The uncontrolled SO2 emissions of 7.0 lb/MMBtu was calculated from permit condition 2.1.2(b)(iv)(B), which requires a 98% SO2 control efficiency if actual SO2 emissions are 0.140 lb/MMBtu or greater. Thus, uncontrolled emissions are: 0.14 lb/MMBtu/0.02 = 7.0 lb/MMBtu. We note that IEPA uses an uncontrolled SO2 emission rate of 6.3 lb/MMBtu. Responsiveness Summary (Ex 4) at n.62. There is no support for this value in the record available to Petitioners at the time this petition was due. Regardless, it would not materially change Sierra Club's analysis here to use 6.3 lb/MMBtu or 7.0 lb/MMBtu.

[39] As discussed, *infra*, IEPA also erred by only calculating cost effectiveness for SO_2 emissions, rather than all pollutants that would be reduced by burning natural gas. Correcting this error by IEPA results in an even lower cost-per-ton.

[40] Assuming IEPA's cost of natural gas (which Sierra Club contends is too high) and SO2 permit limits, the average cost effectiveness = ($8.12/MMBtu)(493 MMBtu/hr)(8760 hr/yr)/[(7.0 lb/MMBtu - 0.00059 lb/MMBtu)(493 MMBtu/hr)(8760 hr/yr)/2000 lb/ton] = **$2,320.2/ton**. The uncontrolled SO2 emissions of 7.0 lb/MMBtu was calculated from permit condition 2.1.2(b)(iv)(B), which requires a 98% SO2 control efficiency if actual SO2 emissions are 0.140 lb/MMBtu or greater. Thus, uncontrolled emissions are: 0.14 lb/MMBtu/0.02 = 7.0 lb/MMBtu. The SO2 emissions assuming gas is burned is calculated from the AP-42 emission factor for natural gas combustion in boilers in Table 1.4-2 (0.6 lb/MMscf/1020 Btu/scf = 0.00059 lb/MMBtu). This is consistent with pipeline quality natural gas. *See, e.g.*, 40 CFR 72.2, 0.5 grains per 100 SCF, which equals 0.00070 lb/MMBtu.

[41] The average cost effectiveness considering all pollutants = ($8.12/MMBtu)(493 MMBtu/hr)(8760 hr/yr)/23,160.0 ton/yr = **$1,514,1/ton**. The total tons of criteria pollutants removed, relative to uncontrolled baseline = 15,114.1 (SO2) + 1,405.7 (NOx) + 6,461.9 (PM10) + 146.8 (CO) + 31.5 (VOC) = 23,160.0 ton/yr. The SO2 emissions removed were calculated as: (7.0 - 0.00059 lb/MMBtu)(493 MMBtu/hr)(8760 hr/hr/2000 lb/ton = **15,114.1 ton/yr**. The NOx emissions removed were calculated as (0.7 - 0.049 lb/MMBtu)(493 MMBtu/hr)(8760 hr/yr)/2000 lb/ton = **1,405.7 ton/yr**. The total PM10 emissions removed were calculated from the total PM10 permit limit of 0.03 lb/MMBtu, assuming 99% control, as (0.030/0.01 - 0.00745 lb/MMBtu)(493 MMBtu/hr)(8760 hr/yr) = **6,461.9 ton/yr**. The CO emissions removed were calculated as (0.15 - 0.082 lb/MMBtu)(493 MMBtu/hr)(8760 hr/yr)/2000 lb/ton = **146.8 ton/yr**. The VOC emissions removed were calculated as (0.020 - 0.00539 lb/MMBtu)(493 MMBtu/hr)(8760 hr/yr)/2000 lb/ton = **31.5 ton/yr**. The uncontrolled baseline for CO and VOC is based on the permit limits as the proposed solid fuel boiler does not include any controls for these pollutants. The uncontrolled NOx is assumed to be 1 lb/MMBtu, based on AP-42, Table 1.1-3, pre-NSPS dry bottom tangentially fired boiler, converted as: (15 lb/ton)(200,000 ton/yr)/(493 MMBtu/hr)(8760 hr/yr) = 0.69 lb/MMBtu. Emissions from firing natural gas were calculated using AP-42 emission factors for natural gas fired boilers, Tables 1.4-1 and 1.4-2. The permit

effectiveness used by IEPA, and well within the range of costs borne by applicants using scrubbers to control SO_2 at coal plants.[42] Therefore, even if IEPA made a record to avoid a comparison of costs of natural gas at MGP with costs at similar plants burning natural gas, *NSR Manual* at B.45, and could justify a comparison to costs of control at other facilities to control emissions with other pollution control options, it was still clearly erroneous for IEPA to reject natural gas clean fuel as the basis of BACT for cost-effectiveness reasons.

E. IEPA's Clean Fuels Analysis Failed To Apportion The Cost of Clean Fuel To All Pollutants That Will Be Controlled With Clean Fuels.

As noted above, IEPA determined that use of natural gas, a clean fuel, as the basis of BACT was not cost effective. In its response to comments, IEPA asserts that it reviewed the applicant's analysis, which concluded that the cost of using natural gas to reduce SO_2 emissions would be $50,000 per ton. *See* Responsiveness Summary (Ex 4) at 20. IEPA recalculated the cost, and determined a cost-per-ton of SO2 reduction at $34,000 per ton. *Id*. IEPA concluded that this exceeded IEPA's threshold for cost-effectiveness of $10,000 per ton. *Id*. However, IEPA additionally erred in this analysis by failing to fully calculate the cost of control for <u>all pollutants</u> that would be reduced by burning natural gas.

IEPA assumed, incorrectly, that <u>only sulfur dioxide</u> would be reduced to determine

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limits for NOx and CO emissions from the auxiliary boiler are generally lower than the AP-42 emission factors, which if used, would have resulted in even larger emission reductions and thus a lower cost-per-ton value.

[42] See, e.g., *In the Matter of Columbia Gulf Transmission Company*, PSD Appeal No. 88-11 (EAB, Jun 21, 1989) at 825 ($3,000 - 6,500/ton cost effective as of 1988. Converted to March 2009 dollars, this yields an average cost effectiveness range of $4,600 to $9,900/ton.).

a $34,000 per ton cost. IEPA also makes a vague statement, in a footnote, that "[t]he Illinois EPA's assessment also shows an overall cost-effectiveness, also considering the reduction in emissions of PM and NOx that would accompany use of natural gas, at $22,000 per ton." Responsiveness Summary (Ex 4) at 20 n.33. Because IEPA shows no calculations, costs, pollution reductions, or any other basis for this calculation in its response to comments, it is impossible to know exactly how IEPA arrived at its conclusion.[43] To the extent IEPA failed to apportion the cost of natural gas[44] to all pollutant reductions achievable with such clean fuel, IEPA erred and the Board should remand.

When calculating the cost of a control option, such as clean fuel, which reduces emissions of numerous pollutants at the same time, the cost of that control option must be divided between the overall reduction in all pollutant emissions. EPA guidance states that when a control option controls multiple pollutants the costs are to be apportioned to each pollutant before the $/ton is figured for cost effectiveness. *See* Ltr. from Brian L. Beals, Chief Preconstruction/HAP Section, USEPA Air and Radiation Technology Branch, to Edward Cutrer, Jr., Program Manager, Georgia Dept. Natl Resources (March 24, 1997),

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[43] If the Board grants Sierra Club's request to supplement this petition following IEPA's production of the permit record, Sierra Club will attempt to provide additional details about IEPA's calculations—if present and ascertainable in the permit record.

[44] The response to comments states that IEPA "calculated the annual difference in the cost of using coal and natural gas for the proposed facility at $25 million per year, based on Illinois coal at $2.17 per mmBtu and natural gas at $8.12 per mmBtu. The additional capital and operating costs for the proposed facility with use of coal, due to the more complex boiler and necessary emission control system and coal handling equipment, was calculated to be about $14 million per year." Therefore, the cost of natural gas is $11,000,000 per year, based on the difference between the price of the natural gas fuel ($25 million) and the savings in capital costs avoided for not installing a coal boiler ($14 million).

attached as Sierra Club's Exhibit 14. Responding to a question by Georgia permitting authorities of how to account for a control device that reduces both VOC and CO, EPA agreed with the Georgia agency's interpretation that the cost effectiveness should be calculated by "dividing the annualized cost of the control device by the total of the CO and VOC emissions reduced by said device." *Id*. Thus, in this case, the cost of natural gas must be divided by the total reduction of all pollutants reduced with natural gas.

Without correcting for IEPA's error, discussed above, of calculating only incremental cost effectiveness from the baseline of a controlled coal unit, the cost-per-ton of pollutant removed is significantly lower than IEPA assumed. IEPA divided the cost of natural gas between only the reduction in SO_2 emission compared to limits in the permit (323.6 ton/yr).[45] Firing gas, however, would also achieve reductions below the permitted limits for NOx (118.6 ton/yr);[46] CO (146.8 ton/yr);[47] total PM10 (48.7 ton/yr);[48] and VOCs (31.5 ton/yr).[49] Thus, even using IEPA's incremental-cost-effectiveness-only

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[45] SO2 reduction: (0.185 – 0.00059 lb/MMBtu)(493 MMBtu/hr)(8760 hr/yr)/2000 lb/ton = 398.2 ton/yr.

[46] NOx reduction: (183.4 ton/yr - 0.030 lb/MMBtu)(493 MMBtu/hr)(8760 hr/yr)/2000 lb/ton = 183.4 - 64.8 = 118.6 ton/yr. The gas emission factor of 0.030 is based on the emission rate IEPA assumes for the natural gas boiler at MGP. Permit § 2.5.2.6.i.A. The coal case is based on the annual NOx permit limit. Permit, Table I.

[47] CO reduction: (0.15 - 0.082 lb/MMBtu)(493 MMBtu/hr)(8760 hr/yr)/2000 lb/ton = 146.8 ton/yr. The gas emission factor of 0.082 lb/MMBtu is based on AP-42, Table 1.4-1, assuming low-NOx burners and natural gas with a heat content of 1020 Btu/scf.

[48] Total PM10 reduction: (0.030 - 0.00745 lb/MMBtu)(493 MMBtu/hr)(8760 hr/yr)/2000 lb/ton = 48.7 ton/yr. The gas emission factor of 0.00745 lb/MMBtu is based on AP-42, Table 1.4-2, assuming natural gas with a heat content of 1020 Btu/scf.

[49] VOC reduction: (0.02 - 0.00539 lb/MMBtu)(493 MMBtu/hr)(8760 hr/yr)/2000 lb/ton = 31.5 ton/yr. The gas emission factor of 0.00539 lb/MMBtu is based on AP-42, Table 1.4-2, assuming natural gas with a heat content of 1020 Btu/scf. As the Permit does not contain a VOC limit, the typical BACT VOC limit of 0.02 lb/MMBtu for coal fired boilers is used.

method, the total amount of criteria pollutants eliminated by firing gas is 669.2 ton/yr. [50] As a result, dividing the cost of natural gas between the total tons of criteria pollutant pollution reduction (instead of only the 323.6 ton/yr of SO_2 used by IEPA[51]) the incremental cost effectiveness drops from IEPA's $34,000/ton claim to $17,484/ton.[52] As discussed supra, the <u>average</u> cost effectiveness considering *all criteria pollutants* is $1515/ton. Including CO2 in the calculation further reduces incremental cost effectiveness to $110/ton.[53] This is well within the $10,000/ton default threshold used by IEPA.

F. IEPA Erred In Rejecting PRB Coal As Not Cost Effective.

1. IEPA Only Calculated Incremental Cost Effectiveness And Did Not Calculate The Average Cost Effectiveness For Use of PRB Coal.

As discussed above for natural gas, IEPA calculated only the incremental cost effectiveness of using PRB coal compared to Illinois Basin coal. The IEPA made the same errors in its analysis of cost-effectiveness of using PRB coal as it did for natural gas, including reliance solely on incremental cost effectiveness, failing to calculate average cost

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[50] Total tons of criteria pollutants reduced: 118.6 (NOx) + 146.8 ton/yr (CO) +48.7 (PM10) + 31.5 (VOC) + 323.6 (SO2) = **669.2 ton/yr.**

[51] The SO2 reduction used by IEPA, 323.6 ton/yr, is not supported in the record. It is apparently the total controlled SO2 emissions as reported in the Permit, Attachment, Table I. This is the wrong value for cost effectiveness calculations

[52] Incremental cost effectiveness = [$25.7MM - $14MM]/[669.2 ton/yr] = $17,483.5/ton.

[53] As Sierra Club contends above, CO_2 is subject to BACT limits as well. When CO_2 reductions from burning natural gas are included, the incremental cost effectiveness drops even further, to about $110 per ton. Based on the emission factors in AP-42, CO_2 emissions from burning coal at MGP's primary boiler would be 551,000 to 625,000 ton/yr, compared to only 253,938 ton/yr for natural gas: a difference of at least 297,062 tons/year. Therefore the total tons of criteria pollutants removed, relative to uncontrolled conditions = 15,114.1 (SO2) + 1,405.7 (NOx) + 6,461.9 (PM10) + 146.8 (CO) + 31.5 (VOC) + 297,062 (CO2) = 320,886 tons/year. The average cost effectiveness would be ($8.12/MMBtu)(493 MMBtu/hr)(8760 hr/yr)/320,222 = $109.5/ton.

effectiveness, and failing to consider all of the pollutants that would be reduced by using a cleaner coal.

For cleaner coal, IEPA calculated incremental cost effectiveness as the increase in fuel cost ($4,800,000/yr) minus the savings in scrubber variable operating costs ($1,183,600), divided by the decrease in the amount of SO_2 that would be emitted (134.5 ton/yr). This resulted in an incremental cost effectiveness of $26,890/ton. This is the wrong cost metric. It is also calculated from baseless cost assumptions.

IEPA should have calculated the <u>average</u> cost effectiveness by dividing the total annual cost of the SO_2 scrubber ($2,527,800/yr)[54] plus the increase in fuel cost ($4,800,000/yr) by the total tons of SO_2 removed from the baseline emissions. Baseline emissions are uncontrolled emissions, calculated from the applicant's proposed fuel: 7.0 lb SO2/MMBtu. *See NSR Manual* at B.37. This spreads the $4,800,000/yr of additional cost from using PRB coal across the 14,985.6 tons of SO_2 removed[55], resulting in a cost

[54] The total annual cost of an SO2 scrubber ($2,527,800/yr) is the sum of the annualized capital cost ($1,772,980/yr), the variable O&M ($314,820/yr), and the fixed O&M ($440,000/yr). The annual capital cost is calculated assuming a unit cost of $400/kw, based on http://www.powermag.com/environmental/Update-Whats-That-Scrubber-Going-to-Cost_1743.html, calculated as ($440/kw)(50 MW)(1000 kw/MW) = $22,000,000. The capital recovery factor, assuming an interest rate of 7% and a scrubber lifetime of 30 yrs is 0.08059. The annualized capital cost is calculated as: ($22,000,000)(0.08059) = **$1,772,980/yr**. The variable O&M cost is calculated from $270 ton/SO2 removed (calculated in footnote 59), assuming 1,166 tons of SO2 are removed: ($270/ton)(1,166 ton/yr) = **$314,820/yr**. The fixed O&M costs are calculated as 2% of the capital, based on the costs reported in Tables 7.1-2 and 7.2-4 of the Sargent & Lundy reported cited in footnote 58: ($22,000,000)(0.02) = **$440,000/yr**. It is not clear what values, if any, IEPA used for its analysis. Small differences in these values are not determinative. The relevant issue is that IEPA did not do this calculation at all.

[55] The amount of SO_2 removed when firing PRB coal is the difference between the baseline SO2 emissions (7.0 lb/MMBtu)(493 MMBtu/hr)(8760 hr/yr)/ 2000 = 15,115.4 tons/yr) and the emission rate assuming a scrubber that removes 90% of the SO_2 from a coal containing 0.6 lb SO2/MMBtu: (0.6

effectiveness of only \$489/ton,[56] which is well below IEPA's significance threshold of \$10,000/ton.

2. IEPA Erred In Calculating Incremental Cost Effectiveness

In addition to IEPA's failure to calculate average cost effectiveness, IEPA also used erroneous inputs for its incremental cost effectiveness analysis. The IEPA calculated incremental cost effectiveness from the sum of the increase in fuel price from using PRB coal (\$4,800,000/yr) and the savings in scrubber operating cost (\$1,183,600/yr) divided by the difference in SO_2 emissions between PRB and Illinois coal (134.5 ton/yr).

a. IEPA Erred in Calculating the Cost Savings in Scrubber Operating Cost When Firing PRB Coal.

The IEPA calculated the savings in scrubber operating cost, accruing from removing fewer tons of SO_2, by multiplying the assumed variable operating cost of \$100/ton by the reduced amount of SO_2 in the fuel that would have to be removed (11,836 ton/yr) with PRB coal to achieve a lower emission rate. Responsiveness Summary (Ex 4) at n.62. There are several flaws in this calculation, each of which is cumulative and prejudiced IEPA's analysis against PRB coal.

First, the variable operating cost of \$100/ton is not supported in the record available to Sierra Club. IEPA cites to an EPA report: "Controlling SO2 Emissions: A Review of Technologies." However, this report does not contain the \$100/ton relied on

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lb/MMBtu)(493 MMBtu/hr)(8760 hr/yr)(0.1)/2000 lb/ton = **129.6 ton/yr.** This difference is 14,985.8 tons/yr.

[56] Average cost effectiveness of using PRB coal and using a 90% efficient scrubber to control SO2: (\$2,527,800/yr + \$4,800,000/yr)/14,985.8 ton/yr = **\$488.98/ton.**

by IEPA. Instead, it provides models and algorithms for calculating various components of variable operating costs in different units (mills per kilowatt hour). If IEPA used these models and algorithms to calculate mills per kilowatt hour and then to calculate cost per ton of SO_2 removed, IEPA made many undisclosed assumptions to make this conversion. We are unable to reproduce the value IEPA used from the source IEPA cites. IEPA's cost savings value appears to substantially underestimate of the cost saving when burning PRB coal.

Second, the EPA report that IEPA relied on is based on data that is more than a decade old. The record contains no evidence that IEPA adjusted its extrapolated value for escalation in costs that has occurred since the 1990s. For example, simply escalating IEPA's assumed costs, based on 1999 dollars, to current dollars results in variable operating costs in March 2009 of $135/ton savings with PRB coal.[57]

Third, the U.S. EPA report that IEPA relied on is based on a conventional wet scrubber (LSFO) designed to remove only 90% of the SO_2 from coals with 2% or more sulfur. The MDP plant will use a circulating scrubber. Hr'g Tr. (Ex 3) at 24 ln. 19. In other words, the cost information IEPA used was not for the type of scrubber that IEPA applied it to. Sargent & Lundy, an engineering firm that designs and builds scrubbers, estimated the variable operating costs for three types of scrubbers firing a range of coals.[58] These estimates include a circulating scrubber burning high sulfur and PRB coal. The

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[57] Adjusted variable operating costs = ($100/ton)(522.6/390.6) = $133.8/ton. Cost indices based on CESPI index published in Chemical Engineering.

[58] Sargent & Lundy, Flue Gas Desulfurization Technology Evaluation, Dry Lime vs. Wet Limestone FGD, Prepared for the National Lime Association, March 2007.

variable operating cost, based on these estimates, is $270/ton,[59] or nearly three times higher than assumed by IEPA. This change, alone, reduces the incremental cost effectiveness from $26,890/ton to $11,928/ton,[60] which is well within 30% of the default average cost effectiveness threshold of $10,000/ton used by IEPA.[61]

Fourth, IEPA is correct to account for the fact that there are lower variable operating costs with PRB coal. However, variable operating costs are not the only costs that would decrease in the PRB case. Annual capital cost and fixed operating costs would also decrease as a smaller scrubber could be used for the PRB coal. These costs cannot be estimated based on available information in the record, but would further lower the incremental cost effectiveness of the PRB case.

b. IEPA Underestimated The Reduction in SO_2 Emissions That Would Be Achieved With PRB Coal.

The IEPA estimated the incremental reduction in SO_2 emissions from switching from Illinois Basin to PRB coal as 134.5 ton/yr (323.6 - 189.1). This value was calculated

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[59] The Sargent & Lundy Report, Table 4.1, costed a circulating scrubber designed to remove 97.2% of the SO2 from a PRB coal containing 1.44 lb/MMBtu of SO2 and another designed to remove 98% of the SO2 from a Appalachian coal containing 3.0 lb/MMBtu. The PRB scrubber would remove (4000 MMBtu/hr)(1.44 lb/MMBtu)(8760 hr/yr)(0.972)/2000 lb/ton = 24,522.4 ton/yr. The high sulfur scrubber would remove (4000 MMBtu/hr(3.00 lb/MMBtu)(8760 hr/yr)(0.98)/2000 lb/ton = 51,508.8 ton/yr. Thus, the incremental amount of SO2 removed is 26,986.4 ton/yr. Table 7.2 indicates that the variable O&M costs for the PRB case are $6,409,000/yr and for the Appalachian case, $13,073,000/yr. Thus, the increase in cost to remove an additional 26,986.4 ton/yr of SO2 is $6,664,000/yr. Thus, on a per ton basis, the variable operating cost of a circulating scrubber, based on 2006 dollars, is $6,664,000/51,508.8 ton/yr = $246.9/ton. Escalating to March 2009 dollars: ($246.9)(522.6/478.6) = $269.6/ton.

[60] Revised incremental cost effectiveness = [$4,800,000 - ($270/ton)(11,836 ton/yr)]/(323.6-189.1) = $11,927.7/ton.

[61] Comparison of incremental cost effectiveness to default average cost effectiveness values is wrong for other reasons set forth in this petition. This calculation is provided to demonstrate how just one of IEPA's errors prejudices its analysis against PRB coal.

from the difference between the permitted SO_2 emissions at the plant using Illinois coal, 323.6 ton/yr (Permit (Ex 1), Table I), and a value that IEPA assumed to represent BACT-level emissions when burning PRB coal of 189.1 ton/yr. IEPA attempted to estimate BACT-level emissions for PRB coal based on IEPA's assumption of 90% SO_2 control when firing a PRB coal containing 0.9 lb SO2/MMBtu.[62] However, IEPA's assumptions are inconsistent. Elsewhere, IEPA assumes the SO_2 content of the PRB coal would actually be 0.6 lb/MMBtu, not 0.9 lb/MMBtu. Responsiveness Summary (Ex 4), n.62. Using IEPA's own 0.6 lb/MMBtu value (that is actually more typical of PRB SO_2 content), combined with IEPA assumed 90% SO_2 control efficiency, results in SO_2 emissions of 129.6 ton/yr,[63] compared to 189.1 ton/yr used by IEPA. This makes the incremental SO_2 reduction when using PRB coal even greater and, consequently, the incremental cost effectiveness lower. Merely using IEPA's own 0.6 lb/MMBtu assumption for typical PRB coal reduces the incremental cost effectiveness from $26,890/ton to $18,641/ton.[64] This change plus the adjustment for variable operating costs discussed supra would result in an incremental

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[62] The calculation that IEPA actually made is much more convuluted. The IEPA calculated SO_2 emissions when firing PRB coal from: (0.09/0.154)(323.6) = 189.1 ton/yr. The 323.6 ton/yr is the permitted annual SO2 emissions from the Permit, Table I. The 0.09 lb/MMBtu is the controlled SO2 emission rate, assuming 0.9 lb/MMBtu coal and 90% control. The 0.154 lb/MMBtu is the expected SO2 emission rate, calculated from 383.6 ton/yr/4,200,000 MMBtu/yr. *See* Responsiveness Summary n.62.

[63] SO2 emissions assuming 0.6 lb/MMBtu PRB coal and a scrubber that achieves 90% SO2 control: (0.6)(1-0.9)(493 MMBtu/hr)(8760 hr/yr)/2000 lb/ton = **129.6 ton/yr.**

[64] Revised incremental cost effectiveness, assuming a permit limit of 0.06 lb/MMBtu for the PRB case: (4,800,000 - 1,183,600)/(323.6-129.6) = **$18,641.2/yr.**

cost effectiveness of $8,270/ton,[65] which is lower than even IEPA's default average cost effectiveness threshold of $10,000/ton.

III. IEPA ERRED BY NOT REQUIRING A NEW BACT ANALYSIS FOR ANY SOURCE THAT DOES NOT COMMENCE CONSTRUCTION WITHIN EIGHTEEN MONTHS.

Section 52.21(j)(4) of 40 C.F.R. provides:

> For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source.

This provision requires that BACT determinations be updated for phased projects, where some emission sources—constructed in distinct phases—do not begin construction until a later date, even though the project as a whole complies with the requirement in 40 C.F.R. § 52.21(r)(2).[66] The permit for MGP omits this requirement to update the BACT limits for later phases of construction. The Board should remand the permit and require IEPA to include this requirement.

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[65] Revised incremental cost effectiveness, assuming revised variable operating costs based on $270/ton and a PRB SO2 permit limit of 0.06 lb/MMBtu: [4,800,000 - 3,195,720]/[323.6 – 129.6] = **$8,269.5/ton.**

[66] 40 C.F.R. § 52.21(r)(2) provides: "Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Administrator may extend the 18-month period upon a satisfactory showing that an extension is justified. This provision does not apply to the time period between construction of the approved phases of a phased construction project; each phase must commence construction within 18 months of the projected and approved commencement date."

Sierra Club raised this issue in its public comments. *See* Sierra Club Comments (Ex 2) at 27. Specifically, Sierra Club commented that:

> The Draft Permit states that it "shall become invalid if construction of the affected boiler is not commenced within 18 months" after the effective date of the permit. Draft Permit, Project Condition 1.8(b)(i). This requirement must clarify that a new BACT determination and modeling analysis must be obtained for any emission source that does not commence construction within 18 months. Because this project will be a staged construction project, including two boilers to be constructed and brought online at different times, the permit must provide for revisiting the BACT limits for any unit that does not commence construction within 18 months, or that has a gap in the construction schedule of 18 months.
>
> Additionally, as written, the provision could be misinterpreted to mean that the same BACT determinations and modeling analyses could be reused in a new permit application. If 18 months pass[], a new BACT analysis must be done. Also, the current provision refers only to "construction of the affected boiler" when it should refer to construction of any emission source.

Id.

The IEPA appears to have misunderstood this comment, which was based on the requirement to obtain a revised BACT limit in 40 C.F.R. § 52.21(j)(4), because IEPA's response focuses on the permit expiration provisions in 40 C.F.R. § 52.21(r)(2). Responsiveness Summary (Ex 4) at 54. IEPA's response states:

> [Condition 1.8(b)(i)] of the draft permit generally reflects the relevant language of the PSD rules, 40 CFR 52.21(r)(2), as specifically indicated in the condition. The PSD rules do not indicate that a new BACT determination and modeling analysis must be obtained for any emission unit that does not commence construction within 18 months, as suggested by this comment. Moreover, the further suggestion that this is needed because the project will be a "staged construction project" is

> not supported by the nature of the project. The PSD rules at 40 CFR 52.21(r)(2) specifically acknowledge that there can be a gap in construction of more than 18 months between the completion of one emission unit and commencement of the next emission unit when the PSD permit is a "phased construction project." However, the project addressed by the draft permit is not a phased construction project. That is, once construction is commenced, MGP has not requested that the permit provide for a period of more than 18 months in which no construction activity would take place.
>
> … 40 CFR 52.21(r)(2) only states that a PSD permit may be extended "upon a satisfactory showing that an extension is justified." As such, it would not be appropriate for the Illinois EPA in this condition to speculate as to what might constitute a satisfactory showing that a permit extension is justified and what information and determinations would need to be made for such an extension to be warranted.

Id. This response misses the point of Sierra Club's comment. The comment was not that Condition 1.8(b)(i) of the permit does not reflect the language of 40 C.F.R. §52.21(r)(2), but that such language is not sufficient because another requirement applies: 52.21(j)(4). The lack of a permit requirement that MGP reassess BACT for emission units that do not commence construction within eighteen months is particularly important here, where the applicant proposes to build two different boilers, on different time schedules.

To the extent that IEPA's response states that a new BACT analysis is not required for emission sources that do not commence construction within eighteen months, IEPA's response is wrong. That is exactly what 40 C.F.R. § 52.21(j)(4) requires for phased project such as the MGP project at issue here. In the Statement of Basis for the permit (called the "Project Summary" by IEPA), IEPA describes the relationship between the proposed natural gas and proposed solid fuel boilers:

> In addition to the proposed solid fuel-fired boiler, a natural gas fired auxiliary boiler with a nominal heat input of 389 mmBtu/hr is also proposed. It would be used during construction of the solid fuel-fired boiler. Thereafter this boiler would serve as a conventional auxiliary boiler, to supply steam when the main boiler is out of service for maintenance. In this role, the auxiliary boiler would be typically used at an annual capacity factor of no more than 10 percent.

Project Summary (Ex 5) at 2. In other words, the natural gas boiler would be constructed and come on line first, at which time it would be used as the main boiler. The solid fuel boiler would be constructed separately, and would come on line later. The natural gas boiler would operate independently of the solid fuel boiler during the time the solid fuel boiler was being constructed and, after the solid fuel boiler comes on line, the natural gas boiler would be used as an auxiliary boiler. This meets the definition of a phased construction project because the boilers would be mutually independent.

EPA guidance has defined "phased" construction projects. That guidance focuses on whether each emission source is "mutually dependant" on prior phases. *See EPA's Response to Connecticut's Questions Regarding The Construction of a Proposed New Source; Web Technologies, Inc*. at 1-2 (May 19, 1992) (citing 40 C.F.R. § 52.21(j)(4) and (r)(2) and 40 C.F.R. § 51.166(j)(4); 43 Fed. Reg. 26380, 26296 (June 19, 1978)), attached as Sierra Club's **Exhibit 15**. "Mutually dependant" means that construction of one phase necessitates construction of another. *Id*. Specifically, the guidance notes that "a three boiler power plant" is "an example of an independent project"—i.e, is <u>not</u> mutually dependant. *Id.*

EPA guidance has also noted that:

> The preamble to the June 19, 1978 regulations, is clear in its application of the phased permitting provisions to sources

> consisting of mutually independent facilities. In fact, the inclusion of phased permitting provisions was in large part prompted by the need to address phased construction of boilers in the electric utility industry. The U.S. Court of Appeals for the D.C. Circuit, in their June 18, 1979 summary decision, upheld EPA's phased permitting program and specifically mentioned the utility industry as an example of the program's application. As footnote 6 in the PSD preamble states, the boilers at a power plant are considered to be mutually independent facilities.
>
> …
>
> In addition, the Administrator should specify at the time the permit is issued that BACT for the later phases may be reassessed prior to commencement of construction. Construction of each phase must commence within 18 months of the date specified in the permit.

Memorandum from Edward Reich, Director of Division of Stationary Source Enforcement, U.S. EPA to Diana Dutton, Director of Enforcement Division- Region VI, U.S. EPA, *Permitting Multi-Phase Construction Under Prevention of Significant Deterioration Regulations* at 1 (August 20, 1979) (emphasis added), attached as Sierra Club's **Exhibit 16**. As EPA notes in this guidance, the D.C. Circuit Court of Appeals approved of EPA's phased-construction requirements in *Alabama Power v. Costle***:**

> EPA's regulations take into account the need for a comprehensive permit <u>for construction projects that are to be completed in phases (a plan of construction characteristic of the utility industry</u>). The comprehensive permit avoids the requirement of applying for separate permits for each phase...
>
> <u>EPA conditions such comprehensive permits so as to make them available only if the applicant agrees (1) to satisfy an independent BACT determination for each phase</u>; (2) to commence construction on each phase within 18 months of the target date specified in the original application (with a variance procedure available only for the commencement date of the first phase); and (3) to avoid any gaps in the course of construction exceeding 18 months…

606 F.2d 1068, 1092-93 (D.C. Cir. 1979) (emphasis added), modified in part by *Alabama Power Co. v. Costle*, 636 F.2d 323 (D.C. Cir. 1979).

The requirement to update BACT determinations for later phases of a project is also consistent with the policy that BACT limits are to be based on "reasonably current pollution control standards, and on the basis of current information regarding the level of air pollution in the locality where the facility is to be located." *In re New York Power Authority*, 1 E.A.D. 825, 826 (Adm'r 1983) (applying 40 C.F.R. § 52.21(r)(2)); *see also In re Knauf Fiber Glass,* GmbH, 8 E.A.D. 121, 160–61 (EAB 1999) (noting that "a benefit of conducting a permitting process for an expansion at a later date is that advances in air pollution control technology … will be taken into account at that time.").

Here, the independent boilers are mutually independent, meaning they could each operate to produce steam for the facility regardless of whether the other boiler is built and/or operating. These independent boilers—providing redundant ability to meet the facility's full steam load—are analogous to independent units at electrical generating stations: existence of one boiler is not necessary for the operation of the other. Additionally, as IEPA's Project Summary notes, they will be built on different schedules, with the auxiliary boiler being finished and brought online and operated to meet the facility's steam needs until the solid fuel boiler is brought online (if ever). Therefore, the permit issued to MGP should require that if the later phase—the solid fuel boiler—does not commence construction within eighteen months, the applicant must revisit and, as necessary, revise the BACT limits for that boiler. Failure to include such a requirement is clear error.

CONCLUSION

For these reasons we respectfully urge the Board to review and remand the MGP Ingredients PSD permit.

Respectfully submitted, this 20th day of July, 2009.

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