Sierra Club Petition

Exhibit 4

Illinois Environmental Protection Agency
Bureau of Air
Permit Section

June 2009

Responsiveness Summary For Public Questions and Comments on the Construction Permit Application from MGP Ingredients of Illinois, Inc., for a Solid Fuel Fired Boiler Facility in Pekin, Illinois

Source Identification No.: 179060AAD
Application No.: 07030058

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DECISION

On June 22, 2009, the Illinois Environmental Protection Agency (Illinois EPA) issued an air pollution control construction permit to MGP Ingredients of Illinois, Inc. (MGP) to construct a solid fuel-fired cogeneration facility at its existing plant in Pekin. In response to public comments, the issued permit includes a number of additional requirements for the proposed project compared to the draft permit, as well as various clarifications to permit conditions.

Copies of the documents can be obtained from the contact listed at the end of this document. The permit and additional copies of this document can also be obtained from the Illinois EPA website www.epa.state.il.us/public-notices/2008/general-notices.html.

BACKGROUND

On March 22, 2007, the Illinois EPA, Bureau of Air received a construction permit application from MGP Ingredients of Illinois, Inc., requesting a permit to construct a solid fuel-fired cogeneration boiler and associated equipment at its existing plant in Pekin. The proposed boiler would be used to generate steam and electric power using coal as the principal fuel. The key emission units of the proposed cogeneration facility would be the solid fuel-fired boiler, a natural gas-fired auxiliary boiler, fuel handling operations and various ancillary operations. While MGP is currently not operating its Pekin plant because of market conditions, MGP has not abandoned its plans for the proposed facility. Indeed, the proposed facility could be important to the continued operation and economic well-being of MGP's Pekin plant.

The construction permit issued for this project identifies the applicable rules governing emissions from the proposed cogeneration boiler and other emission units that are part of the project, and establishes enforceable limitations on their emissions. The permit also establishes appropriate compliance procedures, including requirements for emissions testing, continuous emission monitoring, recordkeeping and reporting. MGP will be required to carry out these procedures on an ongoing basis to demonstrate that the proposed boiler facility is operating within the limitations established by the permit and that emissions are being properly controlled.

COMMENT PERIOD AND PUBLIC HEARING

The Illinois EPA Bureau of Air evaluates applications and issues permits for sources of emissions. An air permit application must appropriately address compliance with applicable air pollution control laws and regulations before a permit can be issued. Following its initial review of MGP's application, the Illinois EPA Bureau of Air made a preliminary determination that the application met the standards for issuance of a construction permit and prepared a draft permit for public review and comment.

The public comment period began with the publication of a notice in the Pekin Daily Times and Peoria Journal Star on May 31, 2008. The notice was published again in the Daily Times and Journal Star on June 7 and 14, 2008. A public hearing was held on July 14, 2008 at the Pekin High School to receive oral comments and answer questions regarding the application and draft construction permit. The public comment period closed on August 13, 2008.

AVAILABILITY OF DOCUMENTS

The permit issued to MGP and this responsiveness summary are available at the Illinois EPA's internet site at http://www.epa.state.il.us/public-notices/2008/general-notices.html.[1] Copies of these documents may also be obtained by contacting the Illinois EPA at the telephone numbers listed at the end of this document.

APPEAL PROVISIONS

The construction permit issued for the proposed project grants approval to construct pursuant to the federal rules for Prevention of Significant Deterioration of Air Quality (PSD), 40 CFR 52.21. Accordingly, individuals who submitted comments on the draft permit or participated in the public hearing may petition the United States Environmental Protection Agency (USEPA) to review the PSD provisions of the issued permits. In addition, any person who failed to file comments or failed to participate in the public hearing on the draft permit may petition for administrative review but only to the extent changes were made to the draft permit by the final permit decision.

As comments were submitted on the draft permit for the proposed project that requested a change in the permits, the issued permit does not become effective until after the period for filing of an appeal has passed. The procedures governing appeals are contained in the Code of Federal Regulations, "Appeal of RCRA, UIC and PSD permits," 40 CFR 124.19. If an appeal request will be submitted to USEPA by a means other than regular mail, refer to the Environmental Appeals Board website at www.epa.gov/eab/eabfaq.htm#3 for instructions. If an appeal will be sent by regular mail, it should be sent on a timely basis to the following address:

U.S. Environmental Protection Agency
Clerk of the Board, Environmental Appeals Board (MC 1103B)
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460-0001
Telephone: 202/233-0122

QUESTIONS AND COMMENTS WITH RESPONSES BY THE AGENCY

1. How much ethanol can MGP produce annually?

   MGP indicates that it has the capability of producing 90 millions gallons of ethanol per year, of which roughly half can be food grade ethanol, which is used for

[1] If necessary arrangements can be made with USEPA, this information may also be available on the Illinois Permit Database at www.epa.gov/region5/air/permits/ilonline.htm (please look for the documents under All Permit Records (sorted by name), Construction Permit Records).

beverages, food products, and pharmaceutical products.

2. How does MGP currently obtain the steam needed for the operation of its Pekin plant?

MGP obtains its steam from boilers at the Indian Trails Cogeneration facility. This is a facility owned and operated by Ameren that is located within the boundaries of the MGP plant. This facility was developed in the early 1990s and replaced the coal-fired boiler that MGP previously operated to provide steam to the plant.

3. Why can't the current arrangements for the supply of steam to the MGP plant continue into the future?

MGP indicates that Ameren is not interested in continuing to operate the existing Indian Trails facility to supply steam to MGP and has plans to let the current contract expire. MGP entered into the original contract for the facility over 15 years ago, when circumstances were significantly different. Natural gas was relatively inexpensive. MGP was working with CILCo, a much smaller power company than Ameren, that at that time provided electric power to the Pekin area. Natural gas is now much more expensive. The Pekin area is now serviced by Ameren, which purchased CILCo in 2003 and took over the contractual obligation to supply steam to MGP. Ameren is a large power company, with over 25 large power plants ranging in capacity from 150 to 2400 MW. The Indian Trails facility has a nominal capacity that is less than 20 MW and its actual output is constrained by the actual steam demand from MGP, which can fluctuate hour-by-hour based on manufacturing operations at MGP. As such, Ameren does not consider it desirable to continue to operate the Indian Trails facility and it has given notice to MGP that it will let the current agreement with MGP expire.

4. I understand why MGP is looking for lower energy costs. I am also looking for lower energy prices.

While 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. In part, the magnitude of this capital cost is due to the cost of the emission control equipment that must be installed on a new coal-fired boiler to comply with applicable environmental requirements. MGP's secondary objectives for the project are to proceed in a way that is affordable and that will hopefully stabilize its energy costs and avoid the future increases in energy costs that would certainly accompany continued reliance on natural gas. This is the reason that the proposed boiler facility would be designed to both produce steam and generate electricity.

5. What does "cogeneration" of steam and electricity mean?

Cogeneration is the simultaneous generation of electric energy and process steam or heat by the same facility. In the case of the Indian Trails facility, when this facility is cogenerating electricity, the high pressure steam from the two main boilers at the

facility, at approximately 1200 pounds per square inch (psi), is first fed to a steam turbine generator to generate electricity. The steam exits the turbine at approximately 165 psi and is then sent to MGP for use in its manufacturing operation.

Cogeneration uses fuel more efficiently than separately generating energy and process steam. For example, cogeneration at the Indian Trails facility takes advantage of the energy or heat value of low pressure steam that is available after generating electricity that cannot be efficiently used for generation of electricity. This low-pressure steam is productively used for process and comfort heating. Coal-fired power plants in Illinois, which are not co-located with manufacturing facilities, do not cogenerate and the heat value of their low quality steam is dissipated by their cooling systems. From an energy perspective, a facility that performs cogeneration is typically over twice as efficient as a facility that only generates electricity.

6. The Intergovernmental Panel on Climate Change has urged urgent action to achieve global warming pollution reductions in the range of 25 to 40 percent by 2020 and 80 to 90 percent by 2050. Any long-term decisions about how MGP meets its energy needs, such as building a new coal-fired boiler, must be consistent with these reduction targets.

The actions recommended by the Intergovernmental Panel on Climate Change, as described by this comment, [2] are at most recommendations that apply to governments around the world, as a whole. It is not appropriate to expect that a particular company can or should individually comply with these recommendations, particularly as reductions in emissions of greenhouse gases will entail comprehensive global action to reduce energy consumption and develop alternative energy systems.

7. While cogeneration should be strongly supported as an efficient and lower-polluting option for MGP to meet its steam and electricity needs, it is not apparent that MGP has considered the environmental impacts of using Illinois coal or the broader global warming and other air pollution impacts of generally using coal. Now, before investing $100 million on a new coal-fired boiler, is an opportune time to assess how the reductions in global warming pollution recommended by the Intergovernmental Panel on Climate Change can be achieved and for MGP to demonstrate its commitment to environmental stewardship. MGP should pull back its application for this project and, at a minimum, reassess the

[2] **The internet site of the Intergovernmental Panel on Climate Change (IPCC) does not provide confirmation of the specific recommendations by the IPCC that are indicated in this comment. As explained at the IPCC's internet site, "The Intergovernmental Panel on Climate Change (IPCC) was established to provide the decision-makers and others interested in climate change with an objective source of information about climate change. The IPCC does not conduct any research nor does it monitor climate related data or parameters. Its role is to assess on a comprehensive, objective, open and transparent basis the latest scientific, technical and socio-economic literature produced worldwide relevant to the understanding of the risk of human-induced climate change, its observed and projected impacts and options for adaptation and mitigation. IPCC reports should be neutral with respect to policy, although they need to deal objectively with policy relevant scientific, technical and socioeconomic factors. They should be of high scientific and technical standards, and aim to reflect a range of views, expertise and wide geographical coverage."**

potential for continuing to use natural gas to generate its steam and electricity.

As a legal matter, MGP fulfills its environmental obligations by complying with applicable environmental laws and regulations. In terms of social and corporate responsibility, MGP fulfills its obligations to shareholders and society at large by using raw materials and fuels efficiently, and by being a good neighbor to the City of Pekin and its residents. It is inappropriate and unrealistic to expect MGP to forgo a project that would enable it to use coal as a fuel when its competitors currently use and will continue to use coal as their fuel.

Global warming and the broader impacts of the use of coal are appropriately addressed by laws and regulations that directly address these matters and establish requirements that are applied in a uniform and equitable fashion to particular classes of sources. With respect to global warming, those laws would preferably be set by Congress on a national level so as to not put states at an economic disadvantage compared to states that have not adopted programs or that have adopted less rigorous programs to address global warming.

8. MGP currently receives steam and electricity from natural gas-fired boilers under a contractual arrangement with Ameren and would continue to receive steam and electricity from a new natural gas-fired boiler until its proposed coal-fired boiler becomes operational. Even after MGP's proposed coal-fired boiler is constructed (if it is constructed), MGP would receive steam and electricity from the proposed new natural gas boiler from time to time when the coal boiler is not available.

This comment reflects an incorrect understanding of MGP's circumstances. First, while MGP does currently receive process steam from natural gas-fired boilers at the Indian Trails facility, MGP obtains its electricity off the grid. In particular, the Indian Trails facility currently operated by Ameren supplies only steam directly to MGP, as necessary to meet MGP's need for steam. Any electricity from the Indian Trails facility goes to the grid. Ameren retains discretion as to how it generates the electricity supplied to MGP. The Indian Trails facility can be and is at times operated to directly supply 165 psi steam to MGP without generation of any electricity.[3] Whether the facility actually operates as a cogeneration facility depends upon the relative cost to Ameren of generating electricity with the facility, which uses natural gas, and with its other power generating facilities, most of which use coal.

Second, the new natural gas-fired boiler now being proposed by MGP would only provide low-pressure process steam for the plant. It would not be part of a cogeneration system and would not be designed for cogeneration as it would not have the ability to generate high-pressure steam. Instead, the gas-fired boiler would be a backup boiler for periods when the solid fuel-fired boiler is not in service.

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[3] The Indian Trails facility has the capability of directly supplying 165 psi steam to MGP through an attemporation system. This system converts high pressure steam into low pressure steam by "diluting" the steam with water. This cools the steam, reducing its pressure, while increasing the quantity of steam as the introduced water evaporates contributing to additional steam.

9. Natural gas is a significantly cleaner fuel than coal, containing virtually no sulfur, ash or mercury. It also emits a fraction of the carbon dioxide emissions of coal when it is burned. Switching from natural gas to coal would be a major step in the wrong direction in terms of air quality and global warming issues.

"Use of natural gas," as proposed by this comment, would not result in lower emissions of CO_2 from the operation of MGP plant. This is because the project that MGP would undertake would be drastically different. Economic and market-based considerations direct the plans of companies, including MGP. These factors have led MGP to propose a facility to meet its need for steam in the future that would be fueled with coal and have the capability to cogenerate electricity. However, if the use of natural gas were made compulsory for the proposed facility, these factors would lead to a drastically different plan by MGP. If MGP could only use natural gas, MGP would not construct a cogeneration facility with its capacity to produce 15 MW of electricity. Instead, MGP would only construct natural gas-fired boilers to generate low-pressure steam to meet the plant's needs for process steam. MGP would purchase all the electricity to run the plant off the grid. This electricity would be generated primarily by existing coal-fired power plants that are not cogeneration facilities, so emit substantially more CO_2 emissions for their productive output than the coal-fired cogeneration boiler proposed by MGP. In addition, the emission rates of these existing coal-fired power plants for SO_2, NO_x, and PM are greater than those of the new boiler proposed by MGP, which would have modern emissions controls.

The change to the nature of MGP's proposed project that would result from "use of only natural gas" is a direct consequence of the relative cost of natural gas and coal. In particular, natural gas is not used in Illinois to provide routine, base-load electrical power, as needed by MGP to operate its plant. In Central Illinois, base-load electrical power is provided by coal-fired power plants. Natural gas is only used for "peaking" electrical power and intermediate or "topping" power during periods when the coal-fired plants cannot meet the demand for electricity. As a result, it would not make economic sense for MGP to attempt to generate its own electricity using natural gas as a fuel, when less expensive electricity can be purchased from coal-fired power plants. This is reflected in the design of the natural gas fired auxiliary boiler, which would be designed to produce low-pressure steam, not the high-pressure steam needed to efficiently generate electricity.

In this regard, MGP's circumstances are the same as Ameren's with respect to the Indian Trails facility. Ameren has no interest in continuing to operate that facility, which is fueled with natural gas. This situation is also generally demonstrated by the new fuel ethanol plants currently being developed in Illinois. These plants generally only use natural gas to meet their needs for process steam and heat. They do not use natural gas to cogenerate electricity and instead obtain their electricity off the grid.

The premise of this comment would only be correct if MGP would cogenerate electricity with natural gas. Only in that case, would the environment actually see a

benefit from the lower CO_2 emission rate that accompanies use of natural gas.[4]

10. Best Available Control technology (BACT) limits should be set for this project for emissions of $PM_{2.5}$. As explained by USEPA in rulemaking proposed on November 1, 2005, "The requirements applicable to NSR SIPs for and the obligation to subject sources to NSR permitting for $PM_{2.5}$ direct and precursor emissions are codified in the existing federal regulations and can be implemented without specific regulatory changes." (70 FR 66,043, November 1, 2005.)

    This comment misconstrues the quoted statement by USEPA, as the statement is provided out of context. The quoted sentence is in a section of this proposed rulemaking dealing with implementation and transition issues associated with New Source Review. USEPA goes on to say that it has found it acceptable to conduct PSD permitting for $PM_{2.5}$ using PM_{10} as a surrogate. "(T)he obligation to implement PSD for the NAAQS was triggered upon the effective date of the NAAQS, as explained in prior guidance ["Interim Implementation for New Source Review Requirements for PM2.5,'' J. Seitz, EPA (Oct. 23, 1997)]. (In that guidance, EPA also explained that PSD permitting for PM_{10} would be accepted as a surrogate approach for this obligation, as discussed in more detail below.)" Accordingly, the statement by USEPA quoted in this comment only addresses the basic legal obligation under the PSD rules and does not indicate how a BACT determination should be conducted for emissions of $PM_{2.5}$.

11. On May 16, 2008, USEPA adopted revisions to the PSD rules to implement PSD for $PM_{2.5}$, defining the "significant emission rate" for $PM_{2.5}$ as an increase of 10 tons or more per year. (73 FR 28,321, May 16, 2008). However, the new provision that would allow PM_{10} to continue to be used as a surrogate for $PM_{2.5}$ for permit applications submitted prior to July 15, 2008 (40 CFR 52.21(i)(1)(xi)), which was also adopted as part of these revisions to the PSD rules, is illegal.[5] If the Court of Appeals vacates or stays this provision of the PSD rules, this project would continue to be a major modification for $PM_{2.5}$. The Sierra Club reserves its right to petition for review of this permit for lack of a BACT limit for $PM_{2.5}$ if USEPA's May 2008 rules are vacated or stayed by the courts.

    Neither MGP nor the Illinois EPA relied on the cited provision of the revised PSD rules to forgo consideration of BACT for $PM_{2.5}$. MGP specifically addressed BACT for emissions of $PM_{2.5}$ in a letter dated May 15, 2008 supplementing its application.[6] **In addition, the Illinois EPA specifically considered control of $PM_{2.5}$ emissions as part of its BACT determination. As such, it is not necessary for the Illinois EPA to**

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[4] **The CO_2 emissions of burning natural gas, in terms of the heat input of fuel, are approximately half those of coal, i.e., 117 pounds per million Btu compared to 205 pounds per million Btu, based on information collected by the Energy Information Administration.**

[5] The provision in the May 16, 2008 rulemaking that would waive the requirement to implement $PM_{2.5}$ BACT by substituting PM_{10} BACT is believed to be unlawful for a number of reasons. It should therefore be overturned by an appeal that is currently pending in the United States Court of Appeals for the District of Columbia. *Natural Resources Defense Council, et al v. EPA,* Case No. 08-1250 (D.C.Cir.).

[6] **In this submittal, MGP confirms that fabric filtration is appropriately considered BACT technology for control of emissions $PM_{2.5}$ from the solid fuel-fired boiler and material handling operations, proposing BACT limits that are identical to those for $PM_{10.}$**

respond to the various arguments put forth by the commenter to support its belief that 40 CFR 52.21(i)(1)(xi) is improper, which arguments may eventually be ruled upon by a federal appeals court.

12. Common particulate control technologies, such as the fabric filter that would be used on the proposed solid fuel boiler, are highly effective at controlling PM and $PM_{10.}$ However, they are less effective at controlling finer $PM_{2.5.}$ $PM_{2.5}$ emissions are more aggressively controlled by controlling the pollutant's precursors. In addition, certain types of filter bags are more effective at controlling direct emissions of filterable $PM_{2.5}$.

The permit for the proposed project provides BACT as specifically recommended by this comment. The permit does set BACT limits for emissions of SO_2 and NO_x, which are the precursor pollutants of concern for $PM_{2.5}$, which react in the atmosphere to form $PM_{2.5}$ and contribute to the ambient concentrations of $PM_{2.5}$. In addition, the BACT determination for direct $PM_{2.5}$ emissions from the solid fuel-fired boiler requires that the baghouse on the boiler be designed and maintained to specifically target control of emissions of $PM_{2.5}$. In particular, Condition 2.1.2(c) of the permit requires that the filter material used in the baghouse be of a type specifically designed for enhanced performance for the control of fine particulate, i.e., $PM_{2.5}$, rather than a conventional filter material.[7] Finally, even if equipped with conventional filter materials, baghouses should not be considered significantly less effective for control of filterable $PM_{2.5}$ than PM_{10}.[8] For solid fuel-fired boilers, baghouses are commonly considered the most effective control technology for control of the filterable emissions, be they PM, PM_{10} or $PM_{2.5}$.

13. Substituting limits for PM_{10} emissions for limits for $PM_{2.5}$ emissions under the PSD rules is arbitrary because PM_{10} is not the same as $PM_{2.5}$. The USEPA should not for expediency in PSD permitting act as if these pollutants are the same. $PM_{2.5}$ has health impacts at lower concentrations than PM_{10}. Condensable particulate comprises a much larger fraction of $PM_{2.5}$ than of larger PM. 73 FR 28,334. Additionally, controls for PM_{10} are not necessarily controls for $PM_{2.5}$ and, more importantly for BACT determinations, top-ranked controls for PM_{10} are not necessarily top-ranked controls for $PM_{2.5}$. *Highwood* at 9, 25 ("[t]he Seitz memo's guidance to rely on BACT analysis for PM10 does not ensure maximum achievable reductions in emissions of PM2.5."), 30 (finding that the vendor

[7] For the solid fuel-fired boiler, as proposed in Condition 2.1.2(c) of the draft permit, "The filter material used in the baghouse shall be a membrane material, micro-fiber material, micro-fiber capped composite material or other similar filter material that has enhanced performance for collection of fine particulate as compared to conventional woven or felt filter material."

[8] When generally discussing the performance of baghouses, the Institute of Clean Air Companies indicates that "Baghouse removal efficiency is relatively level across the particle size range, so that excellent control of PM-10 and PM-2.5 can be obtained." (Institute of Clean Air Companies, *Technologies: Particulate Controls*.) As explained by USEPA, this is because particles are captured by several mechanisms, i.e., inertial impaction, interception, Brownian diffusion, and sieving, on already collected particles that have formed a dust layer on the bags. The fabric material also can capture particles that have penetrated through the dust layer. Electrostatic attraction may also contribute to particle capture in the dust layer and in the fabric itself. Due to the multiple mechanisms of particle capture possible, fabric filters can be highly efficient for the entire particle size range of interest in air pollution control. (USEPA, *Module 6: Air Pollutants and Control Techniques – Particulate Matter – Control Techniques*.)

instructed applicant that it could deal with $PM_{2.5}$ BACT limits by installing more efficient bags, but that the applicant should avoid tipping off the state agency "to avoid any tighter restrictions being placed upon us.").

On April 24, 2009, USEPA announced that it intends to repeal 40 CFR 52.21(i)(1)(xi), the current "grandfathering" provision for $PM_{2.5}$ in the PSD rules. It also immediately stayed this provision for a period of three month.[9] Any permanent repeal of this provision would only occur following opportunity for public comment as a result of formal rulemaking.

Notwithstanding this development, the historic approach taken by USEPA for the "introduction" of $PM_{2.5}$ into PSD permitting, which was reflected in the grandfathering provision, was not arbitrary.[10] The approach reflects a reasoned approach based on the overlapping nature of PM_{10} and $PM_{2.5}$, which enables PM_{10} to serve as an effective surrogate for $PM_{2.5}$. Emissions of $PM_{2.5}$ also constitute PM_{10}, as $PM_{2.5}$ is a subset of PM_{10} with an aerodynamic diameter of less than 2.5 microns. While the percentage of condensable particulate in $PM_{2.5}$ emissions may be higher than in PM_{10} emissions, the absolute amount of condensable particulate in $PM_{2.5}$ and PM_{10} emissions is commonly the same. While progress has been made in addressing the technical issues involved with implementation of PSD for $PM_{2.5}$, significant issues have yet to be resolved. Notably, USEPA has not finalized a reference test method for $PM_{2.5}$ and there is a dearth of $PM_{2.5}$ emission data for emission units based on actual

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[9] In a letter dated April 24, 2009, to Paul Cort, Earthjustice, Lisa Jackson, Administrator of USEPA, announced that the USEPA was granting a petition for reconsideration of the grandfathering provision related to $PM_{2.5}$ in the PSD rules, with the intention of eventually repealing the provision. In addition, Administrator Jackson announced an immediate stay of the grandfathering provision for a period of three months

[10] When USEPA adopted its revisions to the PSD rules to address emissions of $PM_{2.5}$, it also adopted a transition provision that shielded or grandfathered pending permit applications from the new requirements provided that the pending application used PM_{10} as a surrogate for $PM_{2.5}$. In particular, 40 CFR 52.21(i) and (i)(1)(xi) provide "(i) *Exemptions.* (1) The requirements of paragraphs (j) through (r) of this section shall not apply to a particular major stationary source or major modification, if; … (xi) The source or modification was subject to 40 CFR 52.21, with respect to $PM_{2.5}$, as in effect before July 15, 2008, and the owner or operator submitted an application for a permit under this section before that date consistent with EPA recommendations to use PM_{10} as a surrogate for $PM_{2.5}$, and the Administrator subsequently determines that the application as submitted was complete with respect to the $PM_{2.5}$ requirements then in effect, as interpreted in the EPA memorandum entitled "Interim Implementation of New Source Review Requirements for $PM_{2.5}$" (October 23, 1997). Instead, the requirements of paragraphs (j) through (r) of this section, as interpreted in the aforementioned memorandum, that were in effect before July 15, 2008 shall apply to such source or modification."

The USEPA also adopted a transition provision for condensable particular matter. This provision excludes condensable particulate from PM_{10} and $PM_{2.5}$ at the present time. In particular, 40 CFR 52.21(b)(50) and (b)(50)(vi) provide that "*Regulated NSR pollutant,* for purposes of this section, means the following:…(vi) Particulate matter (PM) emissions, $PM_{2.5}$ emissions and PM_{10} emissions shall include gaseous emissions from a source or activity which condense to form particulate matter at ambient temperatures. On or after January 1, 2011 (or any earlier date established in the upcoming rulemaking codifying test methods), such condensable particulate matter shall be accounted for in applicability determinations and in establishing emissions limitations for PM, $PM_{2.5}$ and PM_{10} in PSD permits. Compliance with emissions limitations for PM, $PM_{2.5}$ and PM_{10} issued prior to this date shall not be based on condensable particular matter unless required by the terms and conditions of the permit or the applicable implementation plan. Applicability determinations made prior to this date without accounting for condensable particular matter shall not be considered in violation of this section unless the applicable implementation plan required condensable particular matter to be included."

testing.[11] USEPA also has not adopted significant air quality impact levels for $PM_{2.5}$.

Likewise, the approach taken by the Illinois EPA to the proposed facility's emissions of $PM_{2.5}$ is not arbitrary. Moreover, the approach is also responsive to this comment. Emission rates for PM_{10} are not substituted for or used as limits on emissions of $PM_{2.5}$. Rather BACT limits for emissions of particulate matter from the proposed solid fuel-fired boiler are initially set in terms of particulate matter, rather than PM_{10}, so as to stringently limit the facility's emissions of $PM_{2.5}$. In addition, as related to the *Highwood* Decision, which addressed a proposed coal-fired boiler, the permit requires that the baghouse for the proposed solid fuel-fired boiler use an enhanced filter fabric, which is more effective in controlling $PM_{2.5}$ than conventional filter fabrics.

14. Because $PM_{2.5}$ is a regulated pollutant and would potentially be emitted from the proposed project in a significant amount, a top-down BACT analysis is required for the project for emissions of $PM_{2.5}$.[12]

While the PSD rules at the time that the draft permit was released for public comment did not require a determination of BACT for emissions of $PM_{2.5}$ from the proposed facility,[13] the Illinois EPA considered $PM_{2.5}$ in its BACT determination. For emissions of $PM_{2.5}$, the BACT determination for the proposed project is based on the fact that $PM_{2.5}$ emissions are a subset of emissions of PM_{10} and are controlled by the same devices and measures that control emissions of PM_{10}. The difference is that emissions of PM_{10} may also contains larger particles, which have an aerodynamic diameter greater than 2.5 microns, which $PM_{2.5}$ does not. It should also be recognized that the PSD rules do not specify how a permitting authority must make a BACT determination, much less specify that BACT determinations must be made using a "top-down method."[14] While BACT determinations are commonly made

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[11] USEPA only recently formally proposed a reference method for $PM_{2.5}$ on March 25, 2009, Methods for Measurement of Filterable PM_{10} and $PM_{2.5}$ and Measurement of Condensable Particulate Matter Emissions From Stationary Sources (74 FR 12969). The proposed test method would only be suitable for measurement of $PM_{2.5}$ emissions from stacks that do not have entrained moisture droplets and could not necessarily be used on emission units controlled with wet scrubbers.

[12] To ensure that the limits in a PSD permit ensure the "maximum degree of reduction," based on applicable production processes, fuel cleaning, clean fuels, and other pollution control techniques, a permit applicant is required to propose a permit limit that constitutes BACT and to supply sufficient information on the control option used to achieve that limit. Each step of the BACT analysis and especially a decision to reject a more effective pollution reduction option in favor of a less effective option must be adequately explained and justified. Specifically, 40 CFR 52.21(n)(1)(iii) requires that an applicant for a PSD permit must submit "…a detailed description of the system of continuous emissions reduction planned for the source or modification, emission estimates, and any other information necessary to ensure that best available control technology would be applied."

[13] Because the permit application for the proposed facility was submitted and determined to be complete before July 15, 2008, 40 CFR 52.21(i)(1)(xi), the grandfathering provision for $PM_{2.5}$ in the PSD rules, excused the project from BACT for $PM_{2.5}$. In this regard, the application was clearly complete before July 15, 2008 because the Illinois EPA held the public hearing on the draft permit for the proposed facility on July 14, 2008.

[14] On December 1, 1987, the USEPA implemented certain initiatives to improve the effectiveness of NSR programs within the confines of existing regulations, including the top-down approach to BACT. As explained by J. Craig Potter, Assistant Administrator for Air and Administration, "To bring consistency to the BACT process, I have authorized OAQPS to proceed with developing specific guidance on the use of the "top-down" approach to BACT. The first step in this approach is to determine, for the emission source in question, the most

using the top-down method developed by USEPA, this method accommodates judgment by the permitting authority in the extent of investigation that is conducted. This is because this method focuses attention on the most stringent or "top" control alternative, with the presumption that the top control alternative should be determined to be BACT unless the permitting authority determines that it is not achievable. The top-down method does not require a permitting authority to conduct a detailed evaluation of lesser ranked control technologies, which would be an academic exercise merely to confirm that lesser ranked control technologies are indeed less effective.

Accordingly, the BACT analysis for $PM_{2.5}$ emissions for the proposed project follows a very straightforward path. In particular, for the proposed solid fuel-fired boiler, a baghouse or fabric filtration is generally considered the best control technology for emissions of filterable particulate matter as the emissions of solid fuel-fired boilers cannot be controlled by application of pollution prevention techniques. Fabric filtration is feasible for the proposed boiler as the temperature and other conditions of the exhaust gas and the character of the particulate from the boiler would not preclude use of fabric filtration.[15] In considering the performance of filtration control devices, it is recognized that some filter fabrics are more effective than other filter fabrics. New designs of filter fabrics have been developed that are more effective than traditional filter fabrics for control of fine particulate.[16] Accordingly, "enhanced" fabric filtration has been determined to constitute BACT for the particulate emissions from the proposed solid fuel-fired boiler, for PM, PM_{10} and $PM_{2.5}$. The emission limit that was proposed and is set as BACT for filterable particulate is 0.012 lb/million Btu, as PM. This reflects an emission rate that is achievable, i.e., that has been consistently demonstrated to be met by emission tests of existing coal-fired boilers with baghouses, and provides an appropriate safety margin to account for normal variation in performance of a baghouse.

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stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically or economically infeasible for the source in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. Thus, the "top-down" approach shifts the burden of proof to the applicant to justify why the proposed source is unable to apply the best technology available. It also differs from other processes in that it requires the applicant to analyze a control technology only if the applicant opposes that level of control; the other processes required a full analysis of all possible types and levels of control above the baseline case." (Memorandum, J. Craig Potter, December 1, 1987). While the "Top-Down BACT Process" is commonly used for making BACT determinations, its most important attribute is that it is a standardized way for a source to submit its BACT demonstration and a permitting agency to make its BACT determination.

[15] The proposed solid fuel-fired boiler would use a dry scrubber for control of SO_2 emissions, so that the baghouse on the boiler, which would be downstream of the scrubber, will not be subject to elevated levels of moisture and sulfuric acid mist, which would threaten its integrity. In addition, as dry scrubbing minimizes the introduction of liquid droplets of water into the flue gas, it minimizes the formation of sulfuric acid mist and emissions of condensable particulate.

[16] The USEPA's Environmental Technology Verification (ETV) Program has verified the effectiveness of such filter materials as a technique to improve the performance of baghouses for emissions of $PM_{2.5}$. However, the ETV testing is performed on samples of the fabric, using laboratory procedures to generate a precise loading of particulate to the ample of filter fabric. The ETV testing does not address the actual $PM_{2.5}$ emissions of units controlled with baghouses with enhanced fabrics, so does not provide a basis to set a numerical BACT limit for emissions of $PM_{2.5}$.

For the auxiliary boiler, use of natural gas has been selected as BACT for particulate matter. Since all of this boiler's particulate matter emissions should constitute $PM_{2.5}$, based on USEPA emission factors, the BACT determination for particulate matter directly address emissions of $PM_{2.5}$. For material handling operations and roadways, in which particulate matter emissions are generated by mechanical processes rather than by combustion, $PM_{2.5,}$ will only be a fraction of the PM_{10} emissions. Accordingly, BACT measures for particulate matter emissions of these units are also adequate and appropriate to address the PM_{10} and $PM_{2.5}$ fractions of their emissions.

This comment has not challenged the determination of BACT for particulate matter that was made for the proposed project. In particular, for the proposed solid fuel-fired boiler, this comment does not question the selection of enhanced fabric filtration as the BACT control technology for emissions of particulate matter measured as PM and PM_{10} or the accompanying emission limit selected as BACT. The comment only challenges the BACT determination as related to $PM_{2.5}$. However, as a baghouse or fabric filtration constitutes BACT technology for PM and filterable PM_{10}, it also constitutes BACT technology for emissions of $PM_{2.5}$. The further consideration is whether a different emission limit should be set as BACT for $PM_{2.5}$. As a general matter, reliable emission data is needed to set a BACT limit, since a BACT limit must be achievable on a routine, continuing basis, considering normal variation in the performance of a control system when properly operated and maintained. However, reliable data for emissions of $PM_{2.5}$ is not available for new coal-fired boilers equipped with modern baghouses and advanced filter materials.[17] Accordingly, an empirical basis is not available at this time to set a BACT limit for the emissions of $PM_{2.5}$ from the proposed boiler that would be lower than the BACT limit for PM and PM_{10}, for which empirical data is available. Such empirical data is needed for the performance of a baghouse because of the complexity of a baghouse, in which different physical mechanisms act in concert to capture particles. The filter bags also operate dynamically as they gradually build up a filter cake made up of accumulated particulate and the bags must be periodically cleaned to remove the filter cake.

In response to this need to collect empirical data for filterable $PM_{2.5}$ emissions, the issued permit does require a series of at least three tests for the emissions of filterable $PM_{2.5}$ from the solid fuel-fired boiler, with this testing to be completed during the first three years of operation of the boiler.[18] Because the filterable $PM_{2.5}$ emissions of the proposed project are no longer "grandfathered" from the PSD program as a "pending application," the issued permit further provides that a BACT limit expressed in terms of $PM_{2.5}$ will be set for the solid fuel-fired boiler based on the results of such testing and other relevant information. For this purpose, the issued permit sets a target or default BACT limit for filterable $PM_{2.5}$ emissions of 0.008

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[17] The USEPA only recently proposed amendments on March 25, 2009, to Test Method 201A to establish a reference method for measurement of emissions of $PM_{2.5}$. Proposed Rule: Methods for Measurement of Filterable PM_{10} and $PM_{2.5}$ And Measurements of Condensable Particulate Matter Emissions from Stationary Sources, 74 FR 12,971 (March 25, 2009)

[18] This period may be extended for a further year upon a showing by MGP that additional time is needed, provided that another test is conducted during this year.

lb/mmBtu. This accounts for the required use of an enhanced filtration fabric in the baghouse for the boiler, based on the premise that only half of the particulate emissions from the boiler can be attributed to the filter fabric in the baghouse and thus will be controlled with an enhanced filter fabric in the baghouse.[19] If the results of the required emissions tests for $PM_{2.5}$ and other relevant information show that a limit of 0.008 lb/mmBtu is not "achievable," as that term is used in the definition of BACT in the PSD program, a limit would be set at a level that is achievable, which in no case would be more than the BACT limit that is set for filterable PM emissions from the boiler, i.e., 0.012 lb/mmBtu.

Upon further reflection, it has also been realized that initially setting a BACT limit in terms of $PM_{2.5}$ that would be identical to the limit that is set for PM_{10} would be unsound. This is because it would potentially exclude larger particulate with an aerodynamic diameter between 2.5 and 10 microns from the determination of compliance for $PM_{2.5}$, thereby allowing more emissions of $PM_{2.5}$ than allowed by a limit set in terms of PM_{10} or PM. Particles larger than $PM_{2.5}$ are included in the historic test data for PM emissions and in the established limits for emissions of PM that are the basis of the BACT determination for particulate matter. Indeed, as testing of filterable particulate matter emissions of coal-fired boilers is routinely conducted using USEPA Method 5, it is appropriate that the proposed boiler's emissions of $PM_{2.5}$ and PM_{10} initially be addressed in terms of the boiler's PM emissions. Until the BACT limit in terms of $PM_{2.5}$ becomes effective this will result in the most stringent limit for particulate matter, as all particulate in the exhaust gas of the boiler, irrespective of its size, is addressed by the initial BACT limit.[20]

15. In the Project Summary, the Illinois EPA stated that the BACT limit for PM_{10} "also serves to control particulate matter as $PM_{2.5}$." But that limit corresponds to the PM_{10} limit and is not the result of an independent, top-down (or equivalent) BACT determination for $PM_{2.5}$. Illinois EPA's failure to include a sufficient $PM_{2.5}$ BACT limit is erroneous as a matter of law. This is a deficiency that must be corrected before a PSD permit can issue.

This comment does not demonstrate that the emission limits proposed as BACT for

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[19] The permit sets a BACT limit of 0.012 lb/mmBtu for filterable particulate matter emissions, as would be measured by USEPA Reference Method 5. For purposes of the target value for emissions of $PM_{2.5}$, it is presumed that one half of the particulate emissions would be attributable to the filter fabric or filter media and the rest of the emissions would be attributable to other factors that affect the performance of the baghouse, notably leakage around the filter housing. The use of an enhanced filter media can reasonably be relied upon only to reduce the contribution to particulate emissions related to the filter media itself. It is further assumed that the contribution of the filter media to emissions would be reduced by at least 75 percent with the enhanced media, resulting in a target emission limit of 0.008 lb/mmBtu.

$0.006 + 0.75 \times 0.006 = 0.0075$ lb/mmBtu, ≈ 0.008 lb/mmBtu, following appropriate rounding of results.

[20] This approach to BACT for $PM_{2.5}$ is supported by statements by this commenter. In particular, this commenter has effectively suggested that the majority of the particulate emissions from the proposed solid fuel-fired boiler will be $PM_{2.5}$, since it is believed that the performance of a filter is significantly lower for $PM_{2.5}$ than for PM_{10} or PM. Assuming for purposes of discussion that the commenter is correct, this would indicate that the empirical measurements of particulate matter emissions of coal-fired boilers are in fact predominantly made up of and are representative of emissions of $PM_{2.5}$ from the boilers. This supports a position that a BACT limit for emissions of $PM_{2.5}$ from the proposed solid fuel-fired boiler should not be lower than a BACT limit in terms of PM emissions that is based on empirical emission data.

the particulate matter emissions of the proposed project, which are now initially set in terms of PM and/or PM_{10}, also do not serve as BACT for $PM_{2.5}$, providing an effective and appropriate level of control for emissions of $PM_{2.5}$. As such, the comment is not responsive to the quoted statement of the Illinois EPA in the Project Summary for this project. Instead, the comment merely posits a legalistic presumption that the requirement that BACT be set for $PM_{2.5}$ necessarily requires a BACT determination for $PM_{2.5}$ that is completely separate and independent from the BACT determination required for PM_{10}, leading to BACT limits set in terms of emissions of $PM_{2.5}$. However, as a technical matter, as discussed above, $PM_{2.5}$ is a subset of PM_{10} and is controlled by the same family of control technologies as PM_{10}. As such the BACT determination for $PM_{2.5}$ can appropriately be combined with the BACT determination for PM_{10} and does not necessarily have to result from an independent BACT determination, as suggested by this comment. Moreover, this comment does not put forward any substantive deficiencies in the determination of BACT, identifying other control technologies that should be required as BACT or suggesting lower limits are achievable for the project's particulate emissions.

16. Pursuant to Section 169(3) of the Clean Air Act, a BACT determination must include consideration of cleaner production processes and innovative fuel combustion techniques. In the Project Summary, Illinois EPA states that, "[w]hile natural gas has been used in recent years to supply MGP with steam, the cost of natural gas has risen significantly and MGP finds it desirable to switch to a fuel for its steam supply that is less expensive." The Illinois EPA goes on to state that "MGP has made a business decision" to eliminate natural gas as an option that "does not necessarily need to be revisited by the Illinois EPA." This is not a correct interpretation of the BACT requirement. BACT is applicable regardless of an applicant's business decision or desires. This was confirmed in *In re Hibbing Taconite Company*, 2 E.A.D. 838 (Administrator 1989). [21]

This comment misconstrues the quoted statement in the Project Summary for the proposed project. The statement merely reports the business decision that MGP has made and observes that this business decision alone does not compel a permitting agency's review. In this regard, the Illinois EPA is not aware of guidance that suggests business decisions of the type described, i.e., a company's desire to develop a solid fuel-fired boiler, must be reviewed if the proposed project would provide BACT. In this regard, this comment does not identify any guidance that suggests that companies' business decisions, per se, are subject to review.

Moreover, the statement addressed by this comment does not indicate that it is

[21] In the case of *Hibbing Taconite Company*, Hibbing Taconite sought a permit to modify its furnaces to burn petroleum coke, rather than the natural gas and fuel oil that the furnaces were burning at the time of the application. The USEPA rejected the applicant's argument that the permitting agency must accept the applicant's business decision to burn natural gas "due to the depressed economic situation in the steel industry [and that] natural gas is now too costly." The Administrator reversed the permitting agency's decision because: (1) the fact that the plant burned gas at the time of its application "creates a presumption that natural gas is a financially achievable alternative," (2) the BACT analysis' conclusion that burning natural gas would cost $1310 per ton of SO_2 removed was not a "serious discussion of cost effectiveness;" and (3) the applicant must be required to "show that the natural gas alternative is not economically feasible."

unnecessary to consider use of natural gas as a control alternative in the BACT determination made for the proposed project. Indeed, it is clear that the use of natural gas was considered by the Illinois EPA when determining BACT for the proposed project. The use of natural gas was specifically rejected based on a finding that the cost of controlling SO_2 emissions by this means would be disproportionately high when compared to the costs typically expended for control of SO_2 emissions.

17. In its *Hibbing Taconite* decision, the Environmental Appeals Board specifically considered and rejected the argument that MGP might be tempted to make here that the option of burning natural gas would "redefine the source."[22] The Board's finding in *Hibbing Taconite* applies equally for this project. The MGP plant currently burns natural gas. MGP also intends to construct a natural gas boiler that is capable of meeting its needs (and will meet its needs until the coal-boiler is operational). Burning natural gas will not redefine the source—as it will continue to produce the same product from the same general production process regardless of what fuel is used to create steam. Therefore, rather than begin to use coal, it is reasonable to assume that MGP can continue to rely upon natural gas as a fuel, or alternatively to rely on its natural gas-fired boiler as a cleaner production process. Both options are required under a BACT analysis.

In fact, as acknowledged in passing at the start of this comment, 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."

18. A number of similar plants with the same Standard Industrial Classification (SIC) rely on natural gas boilers, including, for example, a Cargill plant in Shelby County, Tennessee, the Didion Milling plant in Cambria, Wisconsin, and many others across the United States.

There are a large number of plants across the country engaged in various types of grain processing, including plants that produce starch, vegetable oil, sweeteners, flour and various other products for direct human consumption, food ingredients, and animal feed. While the cited plants may be in the same general SIC classification as MGP, which covers the wide range of grain processing plants, they are not in the "same business" as MGP.[23] The relevant plants that are comparable to MGP are

[22] "Traditionally, EPA has not required a PSD applicant to redefine the fundamental scope of its project. However, this argument has not been made, and in any event, the argument has no merit in this case. EPA regulations define major stationary sources by their product or purpose (e.g., "steel mill," "municipal incinerator," "taconite ore processing plant," etc.), not by fuel choice. Here, Hibbing will continue to manufacture the same product (i.e., taconite pellets) regardless of whether it burns natural gas or petroleum coke. Likewise, the PSD guidelines state that in choosing alternatives to be considered in a BACT analysis, the applicant must look to what types of pollution controls other facilities in the industry are using. The record here indicates that there are other taconite plants that burn natural gas, or a combination of natural gas and other fuels. Thus, it is reasonable for Hibbing to consider natural gas as an alternative in its BACT analysis. Moreover, because Hibbing is already equipped to burn natural gas, this alternative would not require a fundamental change to the facility." Page 843, *In re Hibbing Taconite Co.*, 2 E.A.D., PSD Appeal No. 87-3, Slip Opinion (EAB 1989)

[23] The Cargill plant in Tennessee is not an ethanol plant but a wet corn mill, producing starch and other products from corn. The Didion plant in Wisconsin is a dry corn mill, producing corn meal, grits, and other

those that specialize in production of beverage ethanol, which is suitable for use in beverages and food products. As MGP indicated at the public hearing, its major competitors are actually using coal. Consequently, MGP is currently at a significant economic disadvantage compared to its competitors.[24]

More generally, the fact that certain manufacturing plants are currently supported with natural gas-fired boilers does not demonstrate that MGP should not be allowed to build and operate a coal-fired boiler. There are many manufacturing plants across the country that are supported with coal-fired boilers. In addition, electricity is commonly generated with coal-fired power plants. The relevant issue is whether MGP's application for the proposed solid fuel-fired boiler complies with applicable regulatory requirements for development of a new boiler. This it does as it shows that emissions of the proposed boiler would be appropriately controlled and would not cause or contribute to violations of air quality standards.

19. It is my understanding that approximately 60 ethanol plants are either existing or being proposed in Illinois and over 90 percent (all but two) are served by gas-fired boilers, rather than coal-fired boilers.

As explained above, the circumstances of other ethanol plants in Illinois are not directly relevant to the review and permitting of MGP's proposed solid fuel-fired boiler. In addition, this comment does not accurately reflect the circumstances of ethanol plants in Illinois. There are four existing ethanol plants in Illinois, which were in existence as of 2000, including MGP. MGP is the only such plant that currently does not operate a coal-fired boiler. (In fact, MGP also had a coal-fired boiler until 1995, when that boiler was shut down.) Thus existing ethanol plants in Illinois are commonly equipped with coal-fired boilers. Only the new fuel ethanol plants, which have been developed or proposed since 2000, are overwhelmingly fired on natural gas.[25] **However, these plants are not directly comparable to MGP as they are only designed to produce fuel ethanol. The specifications for fuel ethanol are less demanding than those for beverage ethanol, which must be distilled multiple times to obtain the necessary level of quality.**[26]

20. Natural gas is a fossil fuel, but is significantly cleaner than coal. It contains no sulfur or mercury and emits a fraction of the CO_2 emissions. Natural gas clearly is an available fuel, since it is currently the fuel for the existing facility that supplies steam to MGP, the fuel

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edible products from corn. Didion recently added a fuel ethanol facility with an annual capacity of about 40 million gallons per year to its existing dry corn mill.

[24] **MGP has indicated that its major competitors, which have coal-fired boilers, are: 1) ADM, Peoria, Illinois; 2) ADM, Cedar Rapids, Iowa; 3) Grain Processing, Muscatine Iowa; and 4) Aventine Renewable Energy, Pekin, Illinois.**

[25] **Of the ten new ethanol plants that have been or are likely to be developed in Illinois since 2000, only one plant is being developed with a coal-fired boiler.**

[26] **Since steam is the source of the heat for the distillation process used in the manufacture of ethanol, significantly more steam is needed to produce a gallon of beverage alcohol than a gallon of fuel alcohol. Accordingly, steam or energy costs are a larger factor in the cost of producing beverage ethanol than producing fuel ethanol. More broadly considered, beverage ethanol and fuel ethanol plants operate in different markets and their operations should not be directly compared.**

that MGP is planning to use to supply steam until the coal-fired boiler is operational, and the fuel that MGP plans to use to supply steam from time to time when its proposed coal boiler is off-line. Thus, using natural gas would not require the "plant to be redesigned from the ground up" or "that the plant undergo significant modifications." *Sierra Club v. U.S. E.P.A.*, 499 F.3d 653, 655 (7th Cir. 2007). The top-down BACT analysis must therefore consider the use of natural gas as clean fuel, clean production process, or both. Ideally, MGP would develop a high-efficiency natural-gas fired combined cycle cogeneration facility rather than a coal-fired boiler. Such a facility would be more efficient, i.e., use less fuel, and would emit a fraction of the emissions.

In fact, as already discussed, restricting the proposed boiler facility to use of natural gas would result in MGP redesigning its proposed facility "from the ground up." This is because the natural gas-fired auxiliary boiler is not designed to produce high-pressure steam to enable the cogeneration of electricity. Only the solid fuel-fired boiler is being designed to support cogeneration. MGP would not use natural gas for cogeneration, just as Ameren is no longer willing to continue to operate the existing Indian Trails facility to use natural gas for cogeneration. [27]

Notwithstanding these circumstances, the 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.

This comment does not demonstrate that a natural gas fired combined cycle turbine facility could serve as a practical alternative to the proposed boiler facility, as was suggested by this comment.[28] **Combined cycle facilities certainly are the most efficient way currently available to generate electricity with natural gas. However, since they achieve this efficiency by using all the steam that is produced to generate electricity, there is no low-pressure steam remaining for process use. The critical element of the proposed project for MGP is to maintain a source of process steam for**

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[27] **If MGP were restricted to use of natural gas for the proposed facility and, as a consequence, proposed a facility to only supply steam, rather than for cogeneration, it would be inappropriate "redefining of the source" to require MGP pursuant to a BACT determination to develop a facility with the capability for cogeneration of electricity. In such circumstances, MGP would be proposing a project whose only purpose would be to provide steam. This is different than the circumstances of the current project, where MGP has proposed a facility with the capability for cogeneration.**

[28] **In a natural gas fired combined cycle facility, the principal item of equipment is a gas or combustion turbine (i.e., a jet engine) that powers an electrical generator. The heat energy in the exhaust from this unit is recovered as steam in a heat recovery steam generator (HRSG), which is used to generate additional electricity via a steam turbine generator. This second step enhances the efficiency of electricity generation, enabling combined cycle facilities to achieve a high thermal efficiency. The facilities are referred to as combined cycle facilities as electricity is generated by both the Brayton thermodynamic cycle with a combustion turbine and by the Rankine thermodynamic cycle with a steam turbine.**

its Pekin plant. Process steam is essential for the operation of the plant and cannot be obtained from the grid like electricity. The proposed boiler facility is designed foremost to meet MGP's need for process steam and only as a secondary matter for cogeneration of electricity.[29] These objectives are met with a conventional cogeneration facility, i.e., with a boiler that produces high pressure steam with which electricity can be generated and an extraction steam turbine that provides the lower pressure steam that is suitable for process use.

Conventional cogeneration technology also has the well-demonstrated ability to meet changes in the need for steam as occur at MGP's existing plant when various manufacturing operations go on and off line. Combined cycle gas turbine technology has developed for electricity production, where the changes in operating levels of the combined cycle generating units are typically gradual, as other generating units are in service to handle and respond to short-term variation in electrical demand. Combined cycle turbine technology has not been developed to reliably address and respond to significant variability in electrical and steam demand, as would be needed to the needs of the MGP plant.[30]

21. The permit record for this project does not demonstrate that use of natural gas is not cost-effective, as is necessary as the use of natural gas is the most stringent control alternative for the proposed project. As explained by USEPA in the NSR Manual

> [An] applicant should demonstrate to the satisfaction of the permitting agency that costs of pollutant removal for the control alternative are disproportionately high when compared to the cost of control for that particular pollutant and source in recent BACT determinations.
> *NSR Manual,* page B.32.

This principle has been confirmed by decisions by the USEPA Environmental Appeals Board.[31] However, this principle was not followed for the proposed project.

In fact, this was exactly what was done for the proposed project. MGP demonstrated to the satisfaction of the Illinois EPA that the costs to reduce emissions through use of

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[29] **It is not appropriate for the permitting process to modify or shift these objectives as it would effectively change the business of MGP's Pekin plant, making it a commercial electric power company, competing in an entirely different market than its current business.**

[30] **"We would like to caution all HRSG End Users who are considering cyclic operations on their Heat Recovery Steam Generator's (HRSG's). Each HRSG and the corresponding operating philosophy requires special attention. …Many HRSG's were designed essentially for "steady state service" operations. If the operating philosophy changes from that for which your units were designed for, then good engineering practice would necessitate that the End User seek guidance with the original equipment Manufacture (OEM) or reputable firm that can perform a cyclic assessment on the cause/effects of the proposed changes."**
Memorandum, Jeff Daiber, Vogt Power International, July 27, 1999.

[31] *Inter-Power*, 5 E.A.D. at 134, "Where the applicant proposes to eliminate the most stringent control alternative on the grounds that it is not 'economically' achievable, EPA guidance provides that the record must show that the option is not cost-effective."
Hibbing Taconite, 2 E.A.D. at 842 (requiring applicant to "provide a detailed consideration of objective economic data, noting that there "was no serious discussion of cost effectiveness," and concluding that "[g]reater efforts must be made by the applicant to show that the natural gas alternative is not economically feasible").

natural gas would be disproportionately high when compared to the cost of emissions control in recent BACT determinations. In this regard, MGP determined that the cost-effectiveness of using natural gas as an approach to control the SO_2 emissions of the proposed facility would be in excess of \$50,000 per ton of SO_2 emissions avoided. The Illinois EPA's independent assessment of costs confirmed costs of at least \$34,000 per ton of SO_2 avoided.[32] This would be an extraordinary cost for control of SO_2 emissions from a coal-fired boiler. 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 SO_2 emissions. The analysis of the cost-effectiveness of the use of natural gas by the Illinois EPA confirmed costs for control of SO_2 emissions that would be in excess of \$10,000 per ton.[33] By comparison, in the *Hibbings Taconite* case, also cited by this comment, the projected cost for that project for control of SO_2 emissions with use of natural gas was a fraction of this level at \$1300 per ton.

Moreover, permits have been and will likely continue to be issued to other manufacturing facilities to construct new solid fuel-fired boilers with similar levels of PM emissions and control of SO_2 emissions as those being required of the proposed solid fuel-fired boiler.[34] This establishes a significant precedent that must be overcome to show that the construction of the proposed solid-fuel fired boiler would be contrary to BACT because the boiler should be developed to fire natural gas, a cleaner fuel. Conceivably, this would support an argument that when considering natural gas as an alternative for a solid fuel-fired project, the higher costs of natural gas should be

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[32] The Illinois EPA 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. This resulted in a cost-effectiveness of \$34,000 per ton of SO_2 controlled for the use of natural gas as a measure to control SO_2 emissions. [(\$25,000,000 - \$14,000,000) ÷ 323.6 = \$22,000 per ton]. The Illinois EPA's assessment does show higher costs for using coal than MGP's evaluation. However, this is to be expected given the nature of the Illinois EPA's assessment, i.e., it was based on USEPA's conservative generic cost-estimates for the costs of boilers and air pollution control equipment.

[33] The Illinois EPA's assessment also shows an overall cost-effectiveness, also considering the reductions in emissions of PM and NO_x that would accompany use of natural gas, at \$22,000 per ton. This level of cost-effectiveness is also considered excessive for the combination of emissions of SO_2, NO_x and PM.

[34] Notably, construction permits have recently been issued for coal-fired boilers at the following manufacturing plants:

Cargill, Blair, Nebraska, September 2006: 1500 mmBtu/hour boiler – SO_2 limits 0.20 lb/mmBtu, 30-day average, for fuel with an equivalent SO_2 content of 2.0 lb/mmBtu or greater and 90 percent control, 30-day average, for fuels with an equivalent SO_2 content less than 2.0 lb/mmBtu but more than 1.1 lb/mmBtu. PM limit 0.12 lb/mmBtu (filterable).

ADM, Columbus, Nebraska – two 1536 mmBtu boilers fired on a blend of coal - SO_2 limits 0.20 lb/mmBtu, 30-day average, for fuel with an equivalent SO_2 content of 2.0 lb/mmBtu or greater and 90 percent control, 30-day average, for fuels with an equivalent SO_2 content less than 2.0 lb/mmBtu but more than 1.1 lb/mmBtu. PM limit 0.015 lb/mmBtu (filterable).

Red Trail Energy, Richardton, North Dakota, September 2004: 250 mmBtu/hr lignite-fired boiler - SO_2 limit 0.09 lb/mmBtu, 30-day average (equivalent to a nominal 96.5 percent reduction in SO_2 for the proposed lignite fuel, with equivalent SO_2 content of 2.39 lb/mmBtu). PM limit 0.015 lb/mmBtu (filterable).

Ag Processing Inc., Hastings, Nebraska, September 2006: 382 mmBtu/hour boiler fired with Powder River Basin coal - SO_2 limit 0.11 lb/mmBtu, 30-day average. PM limit 0.015 lb/mmBtu (filterable).

considered excessive when the emissions of the proposed coal-fired unit would be appropriately controlled to levels that have been determined to constitute BACT.

22. It appears that Illinois EPA's statement that "the calculated cost-effectiveness of using gas…as a means to control SO_2 emissions is on the order of $50,000 per ton" is based on a single paragraph contained in December 2007 letter from MGP's consultants. That paragraph contains no citations or explanation for how the figures were generated. I did not find back-up documentation in the materials provided in response to our request for all documents pertaining to the permit application. This makes it impossible for the public to comment on MGP's calculations and to evaluate whether the various costs of the fuels were added or removed appropriately (such as capital costs, financing, emission rates, waste handling, emission control, etc.). Clearly, this is not the "serious discussion of cost effectiveness" required to justify rejecting a higher ranked pollution reduction option. See *Hibbing Taconite*, PSD Appeal No. 87-3, Opinion (July 19, 1989), page 8.

MGP provided a reasonable discussion of the cost-effectiveness of using natural gas as an alternative fuel for the proposed facility given the nature of the proposed facility. There would be a substantial difference, tens of millions of dollars per year, in the costs of fuel for the proposed facility if MGP used natural gas rather than coal as the fuel for this facility. Given the magnitude of this difference, MGP believed that its discussion was sufficient to show that use of natural gas would not be a cost-effective alternative approach for control of emissions from the proposed facility. For this purpose, MGP focused on the consequences for the emissions of SO_2 from the facility, as use of natural gas would have the greatest effect on its SO_2 emissions.

In response to this comment, which requests a more detailed analysis of the alternative of using natural gas for the proposed facility, the Illinois EPA has conducted a further assessment of the cost-effectiveness of this alternative. While the cost-effectiveness values calculated by the Illinois EPA are lower than those calculated by MGP, the conclusion is the same. Use of natural gas is not a cost-effective alternative for the control of the emissions of the proposed facility.

While certain insights can be obtained from the EAB's decision for Hibbing Taconite, the decision is not directly applicable to the present project. The Hibbing Taconite decision addressed a proposed fuel conversion project in which existing pelletizing furnaces that were being fired on natural gas and fuel oil would be converted to petroleum coke, a solid fuel whose sulfur content is generally similar to that of coal. The circumstances were such that the nominal cost-effectiveness of use of natural gas for control of SO_2 was only $1300/ton, a value that is commonly considered reasonable for control of SO_2 emissions. Moreover, while the permit issued to Hibbings Taconite for its fuel conversion project would have tentatively limited SO_2 emissions to 1.2 lb/mmBtu, it was unclear that this limit would have been practically achievable, given the apparent lack of control equipment specifically installed for SO_2 emissions. It was also unclear that the SO_2 limit of 1.2 lb/mmBtu would have been

enforceable in practice, given certain provisions of the permit.[35] Effectively, the permit for Hibbing Taconite that was appealed would have allowed use of high-sulfur fuel in existing furnaces with only incidental control of SO_2 emissions as provided by the existing control systems for particulate matter.[36] In contrast, the proposed solid fuel boiler project would be equipped with a scrubber system for control of SO_2 emissions, with SO_2 emissions fully limited to no more than 0.185 lb/mmBtu, and a cost-effectiveness for use of natural gas that is readily considered excessive.

23. A more robust analysis of the cost-effectiveness of use of natural gas must be performed. For example, one obvious issue is that the price of Illinois coal has roughly doubled over the past year. MGP assumes a cost of $30 per ton in its December 2007 letter, but Illinois Basin coal has risen to a current figure of $71 per ton, based on information reported by the federal Energy Information Administration.[37]

This comment does not identify a flaw in the evaluation of the use of natural gas as an alternative to the proposed solid fuel-fired boiler. This is because this comment cites data for the <u>commodity spot price</u> of Illinois coal. This is not an appropriate type of data to predict the price of Illinois coal for the proposed facility. A spot price is the price pursuant to a one-time transaction for the "immediate" purchase of a specific quantity of coal from a mine, without any commitments for further purchases.[38, 39] It is not the price for coal over a period of time under a coal supply contract, as would be applicable for the proposed facility as MGP would obtain its coal pursuant to long-term, multi-year contracts.

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[35] **The permit for Hibbing Taconite that was the subject of the appeal set a limit of 1.2 lbs/mmBtu for SO_2 emissions. However, the permit also provided for the limit to be revised upward (without a ceiling) if Hibbing was unable to meet this limit after a short, 9-month trial period. Moreover, Hibbing Taconite stated on the permit record that the pelletizing, which were apparently only controlled with Venturi rod scrubbers, could not possibly meet this limit. Memorandum, June 15, 1989, Mary Jane Angelo, Assistant Judicial Officer, USEPA, to the Administrator, USEPA.**

[36] In discussing the continued use of natural gas by Hibbing Taconite, the EAB states "In my view, Hibbing's ability to continue to operate using natural gas creates a presumption that natural gas is a financially achievable alternative. Of course this presumption can be rebutted, but to do so, Hibbing must provide a detailed consideration of objective economic data. Mere generalizations about the economic woes of the steel industry are not enough. Hibbing's BACT analysis does not contain the level of detail and analysis necessary to overcome the presumption that the natural gas alternative is economically achievable. The BACT analysis shows that the cost of burning natural gas is $1310/ton SO2 removed, however, there is no serious discussion of cost-effectiveness. Greater efforts must be made by the applicant to show that the natural gas alternative is not economically feasible. This might be done, for example, by comparing the costs of burning natural gas with the costs associated with SO2 control used in other similar types of facilities that have gone through PSD review." "Footnote: "In its petition, the Region state that a control cost of $1300 per ton is within the cost range found for BACT determinations, and is therefore reasonable." In re Hibbing Taconite Company, PSD Appeal No. 87-3, Opinion (July 19, 1989), p. 8

[37] Energy Information Administration, Official Energy Statistics from the U.S. Government, Coal News and Markets Report dated August 4, 2008 (available at http://www.eia.doe.gov/cneaf/coal/page/coalnews/coalmar.html).

[38] **As defined by the Energy Information Administration, the spot price is "The price for a one-time open market transaction for near-term delivery of a specific quantity of product at a specific location where the commodity is purchased 'on the spot' at current market rates."**

[39] **It should also be noted that the spot price of coal does not account for the cost of transporting the coal from the mine to the customer. This can be a significant factor in the cost of coal, especially when comparing the cost of coal from the Illinois Basin and the Powder River Basin. A comparison of difference in cost of Illinois Basin and Powder River Basin coal should also consider the significantly lower heat or energy content of Powder River Basin coal, on a Btu per ton basis.**

For purposes of assessing the cost of coal for the proposed facility, a reasonable value is $45.50 per ton (equivalent to $2.17 per mmBtu). This is based on recent information from Platts Infostore for the cost of coal from the Viper Mine, outside Elkhart, Illinois, about 55 miles from Pekin, as delivered by truck to a power plant near Pekin. While this cost for coal is higher than the $30.00 per ton used by MGP in its December 2007 discussions, it only represents an increase of $0.74 per mmBtu. This does not make natural gas a cost-effective fuel for the proposed facility.

As a general matter, the assessment of the costs of fuel for the proposed project should consider fuel costs in a manner that appropriately accounts for and eliminates short-term variability in fuel costs and accurately assess the relative costs of these fuels. This is because the proposed facility would operate for many years. When appropriately considered on this basis, the cost of coal is consistently substantially less than that of natural gas. In particular, the cost of Illinois coal is typically about one quarter that of natural gas, when appropriately considered in terms of the cost per Btu of fuel energy. While the costs of both coal and natural gas are increasing over time, the rate of increase is less for coal. While natural gas and coal both experience price spikes, the spikes are less pronounced for coal. For coal, the effect of price spikes is also routinely avoided or moderated as coal is obtained pursuant to a long-term contract directly with a coal mining company.[40]

24. The project summary mentions the increase and volatility in the cost of natural gas. The federal Energy Information Administration (EIA) publishes information on the cost of natural gas. The price, in dollars per mmBtu, ranged from $1.43 in 2005 to $11.99 in 2006, to $11.31 in 2007, and $11.54 in 2008. This does not seem to be highly volatile. For comparison, at the end of 2006, data from the EIA shows that the cost for Illinois-basin coal was about $34/ton (nominally equivalent to about $1.44/mmBtu). It is now $70/ton (nominally $2.97/mmBtu). That is an increase and volatility in the cost of fuel. For certain coal from outside the Illinois basin, the cost of coal increased even more, from $40 to $130/ton (nominally, $1.54 to $5.00/mmBtu).

This comment confirms greater increases in the cost of natural gas as compared to the cost of Illinois-basin coal. The comment cites data indicating an eight-fold increase in the cost of natural gas. In comparison, the comment cites data showing that the cost of Illinois coal only doubled.[41]

More data than is presented in this comment is needed to assess the volatility of fuel

[40] When a person obtains coal pursuant to a long-term contract, spikes in the reported cost of coal do not translate into an increase in the cost of coal for the purchaser. The contract shields the purchaser from increase in the cost of coal while at the same time guaranteeing that the particular mine has a customer and source of revenue for its coal. Long-term contracts no longer are available for the purchase of natural gas. Natural gas is increasingly handled as a commodity without the cost protection provided by a long-term contract. This is to be expected given the nature of natural gas and its production and distribution. Natural gas is a standardized material that is handled by a pipeline network that is supplied by multiple sources and directly delivers natural gas on an as-needed-basis to large numbers of consuming facilities.

[41] For natural gas, $11.31/mmBtu ÷ $1.43/mmBtu = 7.9. For Illinois Basin coal, $70/ton ÷ $34/ton = 2.06.

cost, which is actually a different measure of cost than the increase in cost over time as addressed by this comment. When the EIA specifically evaluated the volatility of the cost of natural gas in 2007, it observed that "… analyses of natural gas volatility relative to other commodities have ranked it among the highest. Electricity has been the only commodity group with price volatility consistently higher than those of natural gas." "A high degree of price volatility seems inherent in natural gas markets owing to the nature of the commodity, supply capacity constraints, and the sensitivity of peak day demand to temperature."[42]

Moreover, as previously discussed, what is relevant for the economics of this project are both volatility in cost and the average costs of coal and natural gas. Based on EIA data, between 2005 and 2008, the monthly cost of natural gas in dollars per million Btu ranged from a high of about $13.50 and a low of $5.00, averaging $8.76. The monthly cost of Illinois coal on a spot basis, freight on board, ranged from a high of about $4.25 and a low of $1.50, averaging $2.06 per million Btu, reflecting about a four-fold difference in the cost of natural gas and coal. This is consistent with the data used in a 2007 study of the cost and performance of new electric power plants by the Department of Energy. This study used fuel costs of $1.80 and $6.75 per million Btu for coal and natural gas, respectively,[43] reflecting slightly less than a four-fold difference in fuel cost.

25. Another reason why a more robust analysis of the cost-effectiveness of use of natural gas must be performed is the relative cost of a new coal boiler versus relying instead on the steam supply already being provided, or relying on the proposed new gas boiler alone. It is not clear what costs were included or excluded for the truncated "cost effectiveness" analysis that was performed. A transparent cost effectiveness analysis is especially necessary here because the construction prices for coal handling equipment, boilers, and other similar equipment has experienced drastic increases, it is unlikely that the capital cost of an additional coal boiler and associated equipment is cost-effective in terms of dollars per ton of additional emissions.

The analysis of relative costs and cost-effectiveness was more than adequate given the relative difference in the cost of natural gas and coal. The cost of coal is typically 25 percent that of natural gas, with a cost-differential of at least $6 per million Btu.[44, 45] This difference in fuel costs is more than sufficient to compensate for the additional costs that are inherent in construction and operation of a solid fuel-fired boiler and a

[42] Energy Information Administration, *An Analysis of Price Volatility in Natural Gas Markets*, August 2007.
[43] United States Department of Energy, National Energy Technology Laboratory, *Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Final Report*, May 2007, DOE/NETL-2007/1281, page ii.
[44] In its *Annual Energy Outlook 2009*, the Energy Information Administration (EIA) provides data for the production prices of natural gas and coal based on wellhead and minemouth prices, not including distribution or transportation costs. The EIA data shows current production prices for natural gas of about $6/mmBtu, with projected prices of between $8 and $9/mmBtu by 2030, as more expensive resources are tapped to meet demand. For coal, the current average production price of coal for the Illinois Basin (Interior Region) is only about $1.60/mmBtu, with a projected price of only about $1.80 in 2030.
[45] The Illinois EPA's assessment of the potential use of natural gas for the proposed facility was based on costs of $2.17/mmBtu for coal and $8.12 for natural gas, a difference of only 3.75 times and $5.95/mmBtu.

natural gas-fired boiler of the size planned by MGP, i.e., approximately 500 million Btu per hour. While coal is not a cost effective fuel in smaller boilers, the proposed boiler is of sufficient size that the added operational costs for use of coal are easily offset by the savings in fuel cost.[46]

Moreover, the increases in equipment and construction costs experienced in recent years, as mentioned by this comment, would not act to increase the cost of the solid fuel-fired boiler project, on a percentage basis, more that the cost of a natural gas fired boiler project. First, these recent increases in costs affect both natural gas and coal-fired boiler projects. Second, as the solid fuel-fired boiler project is larger and starts with higher costs, the principle of economy of scale indicates that the smaller natural gas-fired boiler project would experience greater relative increases in costs.

26. The public must be given an opportunity to review and comment on such analysis before the permit is issued. At a minimum, Illinois EPA should require a robust cost effectiveness analysis that follows the guidance in the *Air Pollution Control Cost Manual* prepared by USEPA's Office of Air Quality Planning and Standards, and provide that documentation to the public in a new comment period.

The public has been provided with an opportunity to review and comment on the proposed project and draft permit. The logical outcome of this process is that the Illinois EPA thoughtfully consider any comments that are submitted and, as appropriate, take necessary actions to respond to those comments. The information upon which the preliminary determination for this project was made was provided to the public. It did not prevent meaningful public comment, as evidenced by the various comments that were submitted on this topic. Moreover, a decision to supplement the record with additional research or analysis to respond to public comments does not trigger the need for a further opportunity for public comment.

Moreover, as this comment specifically refers to the USEPA's *Air Pollution Control Cost Manual*, this comment suggests a minimum element for the further analysis of the possible continued use of natural gas that is without practical significance. This is because the USEPA's *Air Pollution Cost Control Manual* does not provide guidance on how an analysis of cost-effectiveness should be conducted for use of an alternative fuel as a means to control emissions of SO_2.[47]

27. To the extent that the Illinois EPA relies on MGP's cursory discussion, that analysis is not sufficient to demonstrate that the price of using natural gas is not "cost effective." NSR Manual at B.31; *Hibbing*, 2 E.A.D. at 842. Most pollution controls will cost money but the

[46] As observed by the Pew Center on Global Climate Change, "Coal can provide usable energy at a cost of between \$1 and \$2 per MMBtu compared to \$6 to \$12 per MMBtu for oil and natural gas, and coal pricees are relatively stable.…coal is so expensive that one can spend quite a bit on pollution control and still maintain coal's competitive position." Coal and Climate Change Facts, http://www.pewclimate.org/global-warming-basics/coalfacts.cfm.

[47] At this time, the Table of Contents for USEPA's *Air Pollution Control Cost Manual* (Sixth Edition) indicates that "Fuel Switching" for NOx Control and "Fuel Substitution" for SO_2 control are both planned chapters for the control cost manual.

PSD program does not allow sources to escape emissions control merely because it might cost money. "BACT is required by law. Its costs are integral to the overall cost of doing business and are not to be considered an afterthought." *Id.* at B.31 ("In the economical impacts analysis, primary consideration should be given to quantifying the cost of control and not the economic situation of the individual source."); *see also Alaska Dep't of Environmental Conservation v. EPA*, 124 S.Ct. 983, 1005 (2004) (upholding USEPA's order rejecting a BACT analysis that eliminated a pollution control option on claims of economic infeasibility without an adequate record); *Hibbing Taconite,* Slip Op. at 8 ("Mere generalizations about the economic woes of the steel industry are not enough."). Here, there was no demonstration by MGP or the Illinois EPA that would justify ignoring the lower emissions achievable with cleaner fuel.

The BACT analysis for the proposed project has not ignored the lower emissions levels that would potentially be achievable with the use of cleaner fuels. The BACT determination also does not allow MGP to "escape pollution control merely because it might cost money." Rather the BACT determination requires use of appropriate emission controls on the solid fuel-fired boiler and was based on an analysis that considered use of natural gas as an alternative approach to control of emissions. It was not based on the current economic woes of MGP or the ethanol industry.

28. The Illinois EPA should require MGP to provide a comprehensive analysis of the economic feasibility of using natural gas as fuel. This analysis should be made available to the public for comment before any permit is issued.

The PSD rules do not support the action requested by this comment. In particular, this comment asks for an assessment of the <u>economic feasibility</u> of using natural gas, As such, it asks that MGP make public its economic assessment of the proposed project. This of necessity would also include an assessment of its current economic circumstances, an assessment of its current and planned markets for products, its current and future costs of manufacturing, and information on other financial matters to which the public is not entitled to have access. This request goes far beyond the analysis of cost-effectiveness required for a BACT determination.

29. The analysis of lower sulfur coal is insufficient because lower sulfur coal seams are available in Illinois. There is no discussion about limiting coal sulfur content to lower sulfur coals available in Illinois.

The analysis of the potential coal supply for the proposed project is appropriate as it addresses coal that is commercially available and could be purchased by MGP. The fact that "low-sulfur coal seams" exist in Illinois does not show that coal from such seams is actually mined or should be considered commercially available so as to potentially be used by the proposed facility. In this regard, it is significant that this comment does not actually state that lower sulfur coal is available in Illinois. Rather, the comment only indicates that lower sulfur coal exists in Illinois. While this is a true statement, it is does not show that coal from such seams is economically recoverable, is currently being mined, or will continue to be mined. These are prerequisites for a discussion or detailed evaluation of a potential coal supply as

generally requested by this comment for the use of lower sulfur Illinois coal.

In fact, the lower sulfur coal seams in Illinois are not currently being mined to an extent that ensures that supplies of such coal will continue to available into the future.[48,49] The majority of the coal that is currently being mined in Illinois is higher sulfur coal. The deposits of this coal are of sufficient thickness and extent to be commercially recoverable and there are markets for this coal from electric power plants located outside of Illinois.[50, 51] This is no longer the case for the deposits of lower sulfur coal that remain in Illinois.[52]

30. The analysis of lower sulfur coal is insufficient because there is no basis for assuming that delivery of low sulfur coal is any different than for Illinois coal. Some plants burning low sulfur coal receive it by truck or small train deliveries, and some plants burning Illinois coal receive it by large trains. Even if certain changes to the fuel receiving portions of the MGP plant would need to be redesigned to accommodate cleaner coal, such changes must be considered in a top-down BACT analysis. See e.g., *In re East Kentucky Power Cooperative, Inc., Hugh L. Spurlock Generating Station*, Title V Petition No. V-06-007, Order Responding to Petitioner's Request that the Administrator Object at 30[53] (Administrator Aug. 30, 2007) (finding that the Kentucky Department of Environmental

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[48] **An overview of the coal mining industry in Illinois is available from the *2006 Annual Statistical Report* prepared by the Illinois Department of Natural Resources, Office of Mines and Minerals. This report shows only 22 operating coal mines in Illinois, producing about 33 million tons of coal. Most of the coal was mined at 15 underground mines. In total, they produced 27.4 million tons of coal, with the largest mine producing 7.2 million tons. These mines were producing Danville, Springfield and Herrin coal (Illinois No. 5, No. 6 and No. 7 coal) from seams that were nominally 5 feet or greater. These are the main coal reserves in Illinois and are considered high sulfur coals. The seven surface mines produced about 5.6 million tons of coal in 2006, with the largest mine producing 2.6 million tons. In addition to producing Danville and Herrin coal, three surface mines in southern Illinois each produced coal from more localized coal seams, i.e., the Murphysboro, Friendsville and Allenby (also known as Baker) seams.**

[49] **Information from 2008 from the US Office of Surface Mining and Reclamation and Enforcement, Mid-Continent Region reports only 21 active mines in Illinois, 16 underground mines and 5 surface mines.**

[50] **Information on the recoverable reserves of coal remaining in Illinois and the sulfur content of Illinois' coal reserves is available the 2003 Keystone Coal Industry Manual. It shows that the major reserves of coal remaining in Illinois are the high-sulfur Springfield and Herrin coal seams.**

[51] AS **explained by Emily Medine in "The Illinois Basin: A Second Coming," an article in *Coal Age*, February 2005, "It is the Illinois Basin that many industry participants are now looking to as a domestic replacement for Appalachian coal. The demonstrated reserve base according to the Department of Energy exceeds that of all Appalachia. Illinois alone has demonstrated reserves in excess of 100 billion tons…" "Most of the low sulfur coal in Illinois has already been mined…" "Illinois Basin coals have moved into some 'Appalachian' markets in 2004 and 2005 as a result of the current high-priced environment for Appalachian coals…" "The more significant market potential develops as a result of retrofitting of flue gas desulfurization (FGD) or scrubbers on existing power plants, particularly those plants originally designed for Illinois Basin coals that were switched to lower sulfur bituminous coals in order to comply with environmental requirements."**

[52] **Until recently, Monterrey Mine No. 1 near Carlinville, Illinois was producing "low sulfur" coal, mining a seam with an equivalent uncontrolled SO_2 emission rate of about 1.9 lb/mmBtu. In 2006, the mine was reported to have produced 2.8 million tons of coal. The mine's principal customer was a coal-fired power plant operated by Ameren in Coffeen, Illinois, which used over two-thirds of its output. However, this mine closed in December 2007, and Ameren's Coffeen power station now burns Powder River Basin coal. There is no indication that this mine will resume operation with the lower sulfur coal seam. Interest in resuming operation of this mine has focused on a deeper seam of high-sulfur coal, rather than the lower sulfur coal seam.**

[53] At http://www.epa.gov/region07/programs/artd/air/title5/petitiondb/petitions/east_kentucky_spurlock_response2006.pdf

Quality failed to justify an SO_2 BACT limit and "needs to provide additional analysis and/or a justification for its determination that use of lower sulfur coal was not an achievable option for Spurlock Unit 4.").

In practice, the delivery of low-sulfur coal to MGP would be different than the delivery of Illinois coal. This is because the low-sulfur coal that can be considered available, i.e., coal from the Powder River Basin, would necessarily be transported for a long distance, dictating transport by rail with unit trains.[54] The cost of such rail transport, given the distances involved and the intermediate handling of material that would be needed, would be substantially more than the direct delivery of coal by truck, as typically occurs for small users of coal in Illinois (i.e., sources other than power plants) that are located in the region in which coal is mined. While rail transport of coal has been deregulated and this has meant reductions in coal transportation costs compared to historical costs for some coal-fired electric utilities, it cannot be assumed that this would result in lower transportation costs for MGP. Compared to a coal-fired power plant, MGP would be a "small customer" and would not receive the rates that "large volume" customers receive, given the greater overall value of their business for the railroad or the coal mine.[55]

It is also significant that in the *Spurlock* Case, the USEPA did not remand the permit for proposed Spurlock Unit 4 back to the Kentucky Department of Environmental Quality for failure to consider and appropriately reject use of Powder River Basin coal for the proposed unit.[56] The basis for that decision by the Kentucky Department of Environmental Quality was not questioned by the USEPA. Rather the permit was remanded for further consideration of the potential use of locally available low sulfur coal from the Appalachian Basin for the proposed new unit at this power plant

[54] Unit trains transporting coal only carry coal, travel dedicated routes from the mine to the receiving source without interruption, and then return empty back to the mine for another load. Units trains carrying Powder River Basin coal to Illinois routinely have over 100 cars and are over a mile in length. The most efficient unit trains have the most cars, operate on a regular schedule, use dedicated railroad equipment, travel the most direct routes, and can be loaded and unloaded in a few hours, thereby minimizing the costs associated with transportation of the coal.

[55] The Energy Information Administration observed "Facilities served by rail can negotiate better rates if there is a competing railroad they can use, or a feasible competing transportation mode. 'Captive' mines and coal consumers – those located where a single carrier or mode is their only practical transportation option – have long claimed that they were offered only higher, take-it-or-leave-it rates. Barges generally offer the least expensive transportation rate and facilities that can take advantage of barge shipment for all or even part of the shipping distance can usually temper transportation costs. Different railroads use different rate structures and have in recent years implemented new requirements, such as automated loading and unloading equipment or 7-day-per-week loading and unloading, that affect supplier and customer overhead costs but are not reflected in rates. Rates charged may be lower for customers that lease or own their own fleet of rail cars." Energy Information Administration, *Coal Transportation Rates and Trends*, Data for: 1979 – 2001 (partial 2002), released September 2004.

[56] The Kentucky Department of Environmental Quality determined that the use of coal from the Powder River Basin, as an alternative to the proposed design basis coal for the proposed generating unit, had cost impacts that supported rejection of this alternative as a means to control SO_2 emissions from the proposed unit. For this purpose, the cost for use of this alternative were $8,033 per ton of SO_2 removed and an incremental cost of $23,733 per ton of SO_2 controlled.

located on the Ohio River, in eastern Kentucky.[57]

Finally, the circumstances of the Hugh Spurlock Station, which was cited in this comment, differ significantly from those of the proposed MGP facility. This is because the Spurlock Station is an existing power plant. The cited decision by the USEPA Administrator addressed the proposed addition of Spurlock Unit 4, a fourth generating unit, to this existing power plant that already had equipment and facilities to receive shipments of coal, potentially including shipments of lower sulfur coal.[58]

31. The Illinois EPA's discussion of lower sulfur coal is deficient and is not supported by any evidence in the permit record that I reviewed. In its analysis, the Illinois EPA rejects cleaner coal for two reasons. First, the Illinois EPA expresses undefined "concerns about cost" because low sulfur coal is used nationally. Second, the Illinois EPA expressed undefined "concerns about… operational issues that would be posed for delivery of low sulfur coal to the plant" because Illinois EPA appears to assume that low sulfur coal must be Powder River Basin coal, such coal must be delivered by unit trains, and unit trains cannot deliver coal to MGP. This is an insufficient "analysis."

As already discussed, the analysis of potential use of lower sulfur coal by the proposed facility appropriately uses Powder River Basin coal to address the cost impacts that would accompany this alternative to the coal supply planned by MGP. This is because coal from the Powder River Basin is currently being used at most of the coal-fired power plants in Illinois. Coal from the Powder River Basin can be relied upon to be available for the foreseeable future. The Powder River Basin contains at least 10 billion tons of recoverable coal and in 2007 produced over 400 million tons of coal. Based on historic prices, the cost of Powder River Basin coal at the mine, freight on board, is half that of coal from other major coal basins.[59] **Powder River Basin coal, which contains less than 1.0 percent sulfur by weight, has substantially less sulfur than coal from the Illinois Basin.**

The concerns about the use of Powder River Basin coal cited by this comment are the reasons underlying rejection use of this coal as BACT for the proposed facility. As applied to the proposed MGP facility, Powder River Basin coal would be a significantly more costly "premium coal," whose additional costs are not justified by the accompanying reduction in emissions. This is because the infrastructure to transport Powder River Basin coal directly to the proposed facility, in the manner in which this coal is currently transported to power plants in Illinois, does not exist at the MGP plant. The MGP plant does not have the ability to handle unit trains and is

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[57] **The Kentucky Department of Environmental Quality subsequently conducted additional analysis confirming that the additional cost for low-sulfur coal from the Appalachian basin was excessive, with a cost of $12,000 per ton of additional SO_2 controlled.**

[58] **The existing Spurlock Station has three coal-fired generating units with a total nominal capacity of 1120 MW. When the USEPA Administrator addressed BACT in the decision cited by this comment, the Administrator was addressing the proposed addition of a fourth coal-fired generating unit with a nominal capacity of 300 MW to the station. Coal handling facilities, including facilities to handle coal by barge, were already in place at the station.**

[59] **Current spot prices for coal from major coal basins, freight on board, are on the order of $70 for Central Appalachia, $55 for Northern Appalachia, $60 for the Uinta and $10 for the Powder River Basins.**

too small in size for this capability to be constructed at the plant. In its application, MGP <u>conservatively</u> calculates that if the proposed facility were required to use Powder River Basin coal, the additional annual cost for the coal would be $4.8 million as compared to Illinois coal.[60] This is because of the additional costs for transporting and handling Powder River Basin coal, as compared to Illinois coal, which would be readily delivered directly to the MGP plant by truck on an as needed basis.[61] After considering the savings in operating costs for the scrubber, which would accompany use of Powder River Basin coal, this additional transportation cost for Powder River Basin coal conservatively results in a cost-effectiveness value for the accompanying reduction in emissions of SO_2 that would be in excess of $10,000 per ton of SO_2 emissions that would be avoided.[62] This level of cost impacts for control of SO_2 emissions is excessive and supports rejection of the use of Powder River Basin coal as BACT.[63]

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[60] MGP also speculates that the additional cost for Powder River Basin coal would only be $3,100,000 if a barge terminal facility were developed in the Pekin area to receive and store such coal. However, there is not such a facility at this time and the MGP plant itself does not have the space to store the amount of coal that would have to be stored if coal were received by barge. As such, it is not appropriate to rely on the development of a local barge terminal to handle coal for the proposed facility. Incidentally, even if such a facility were to be developed, the cost-effectiveness based on MGP's information on cost would $10,580 per ton per ton of additional SO_2 controlled, which is still in excess of $10,000/ton.

[61] MGP conservatively assumed that the proposed facility would use only 240,000 tons of Powder River Basin coal per year. Refer to MGP's submittal received January 7, 2009, page 7. This tonnage is greater than the amount of Illinois coal that would be used because the heat content of Powder River Basin coal, about 8500 Btu/pound, is significantly lower than that of Illinois coal, which is typically in excess of 11,000 Btu/pound. A more realistic estimate of the annual usage of Powder River Basin coal would be 250,000 tons, compared to only 200,000 tons of coal for Illinois coal.

[62] The cost-effectiveness of the reduction in SO_2 emissions accompanying use of Powder River Basin coal was conservatively calculated based on an annual reduction of 134.5 tons in the potential SO_2 emissions of the proposed facility, i.e., annual SO_2 emissions of only 189.1 tons, compared to 323.6 tons. This reflects a nominal reduction in SO_2 emissions of 42 percent due to the use of lower-sulfur Powder River Basin coal. This was determined from the ratio of an SO_2 emission rate, in pounds per mmBtu that would likely be set as BACT with Powder River Basin coal and the SO_2 emission rate that is reflected in the annual SO_2 emission limit for the proposed facility. If Powder River Basin coal were used, an SO_2 limit of 0.09 to 0.10 lb/mmBtu would likely be set as BACT for the proposed facility, reflecting achievement of approximately 90 percent control of SO_2 given the lower uncontrolled concentration of SO_2 in the flue gas. (Refer to pages 1-30 and 4-3 through 4-5 of the application and other recent SO_2 BACT limits set for use of Powder River Basin coal, e.g., Lamar Light and Power, Colorado, MidAmerican Energy, Council Bluffs, Iowa, Unit 4, and Cargill, Blair, Nebraska). The annual SO_2 limit for the proposed facility reflects achievement of an annual SO_2 emission rate of 0.154 lb/mmBtu (323.6 tons/yr ÷ 4,200,000 mmBtu/yr = 0.154 lb/mmBtu).

The savings in operational costs from use of Powder River Basin coal was evaluated using a factor of $100 per ton of SO_2 controlled to account for the variable operating costs associated with SO_2 scrubbing, which costs are directly related to the amount of SO_2 that is controlled. This factor was extracted from *Controlling SO_2 Emissions: A Review of Technologies*, USEPA, October 2000. This factor was applied to 11,836 tons of SO_2, which is the calculated difference in the amount of SO_2 emissions that would be controlled annually with Illinois Basin coal at 6.3 lb SO_2/mmBtu equivalent (12,907 tons) and with Powder River Basin coal at 0.6 lb/mmBtu (1,071 tons). This yields an annual savings of $1,183,600, for an adjusted net increase in annual cost of about $3,600,000 ($4,800,000 - $1,183,600 ≈ $3,616,400) and a cost-effectiveness value of about $26,890 per ton of additional SO_2 emissions controlled.

[63] A useful compilation of cost-effectiveness values for control of SO_2 that have been found to be excessive was prepared by the USEPA in the Response to Public Comments to the Deseret Power Electric Cooperative's Bonanza Power Plant draft permit. USEPA found that cost-effectiveness values as low as $5,900 and $6,700 per ton of additional sulfur removed. Another determination of an excessive cost-effectiveness value for SO_2 is available from the review of the East Kentucky Power Cooperative's proposed Unit 17 at the Spurlock

The other factor that would affect the cost of Powder River Basin coal for the MGP facility is competition for this coal. Powder River Basin coal is used nationally to supply much of the coal that is used to generate electricity.[64] If MGP were required to use Powder River Basin coal it would be forced to compete with the large number of coal-fired power plants also using this fuel, many of which are existing plants. Power plants have the ability to receive shipments of coal directly or have coal transferred through major terminals with accompanying operational efficiency and cost savings due to the volume of coal that is handled. Because MGP would be a small customer, it would be at a disadvantage compared to these larger customers and its cost for Powder River Basin coal would be substantially more than that paid by operators of power plants. Even if a smaller power plant does not have the ability to directly receive shipments of Powder River Basin coal, it may rely on the facilities of another nearby power plant under common ownership.[65] MGP cannot rely on such arrangements with existing power plants in its vicinity because it is a separate company and does not control their operations.[66] Moreover, at existing power plants, the use of Powder River Basin coal is often accompanied by additional savings that will not be present for MGP with its proposed facility. This is because the operators of existing power plants do not have to make or may postpone the capital investment in the installation of scrubbers and avoid the fixed annual costs associated with construction and operation of scrubbers. The low sulfur content of Powder River Basin coal is also relied upon by the operators of power plants to provide an SO_2 emission rate that is acceptable without scrubbing. Indeed, for Illinois' existing privately owned power plants, Powder River Basin coal has consistently been found to be less costly than Illinois coal after factoring in the savings for not having to scrub emissions of SO_2.[67] This is not a factor for the proposed MGP facility, whose new

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Generating Station by the State of Kentucky. This determination found that a cost-effectiveness value for SO_2 of $9,317 was excessive.

[64] Coal from the Powder River Basin is currently used in a large number of electric power plants, including power plants in the states of Colorado, Georgia, Illinois, Indiana, Kansas, Michigan, Minnesota, Nebraska, Pennsylvania, Texas, Washington and Wisconsin. The usage of Powder River Basin coal is expected to increase substantially in future years as the recoverable reserves of coal from the Appalachian Basin are depleted.

[65] For example, Ameren handles Power River Basin coal at its Newton power plant, nominal capacity 1230 MW, both for the Newton plant and for its much smaller Hutsonville power plant (nominal 150 MW) located about 50 miles away, with coal transferred from Newton to Hutsonville by truck.

[66] The owners of the nearby power plants, Midwest Generation and Ameren, may have no interest in taking on the function of serving as MGP's coal supplier. They may even be barred from doing so under the terms of their own coal purchase contracts. It would also be contrary to their self-interest to supply coal to MGP, as the proposed MGP facility would cogenerate electricity. Even if an owner of one of the nearby power plants were willing to enter into a contract to supply coal to MGP, it could not be guaranteed that the contract would be renewed or renewed at reasonable terms so as to ensure the continued availability of Powder River Basin coal to the MGP facility by such means.

[67] Given the State of Illinois' interest in supporting Illinois' coal industry, efforts are ongoing by appropriate Illinois state agencies and institutions to facilitate and encourage the use of Illinois coal by existing privately owned power plants in Illinois. At the same time, under current environmental regulations, use of Powder River Basin coal is a less expensive option for most such power plants given the cost at which they can obtain coal from the Powder River Basin. Significant changes in the relative cost of coal or to environmental regulations would have to take place to make Illinois coal more economically attractive. For example, refer to Shiaoguo Chen, Illinois State Geological Survey, "Economic Evaluation of Illinois Coal and Western PRB Coal under Different Pollution Control Scenarios, 2007, project sponsored by the Illinois Clean Coal Institute.

solid fuel-fired boiler would have to be equipped with a scrubber.[68]

32. To the extent that the Illinois EPA claims that the design changes necessary to receive lower sulfur coal are not cost-effective, there is no documentation or discussion in the background materials sufficient to show that cleaner coal should be rejected as BACT.

This comment does not address the information submitted by MGP in its application considering the potential use of low-sulfur coal for the proposed facility, much less show that the information was insufficient. As already discussed, in its application, MGP identified significant additional costs associated with use of Powder River Basin coal because the coal would have to be handled by an intermediary coal terminal and final delivery of coal to the proposed facility would necessarily take place by truck, most likely from an off-site coal terminal located in Chicago, over 170 miles away. This is because the major coal terminals in Illinois that handle shipments of Powder River Basin coal are not located near Pekin. They are located where Powder River Basin coal can be transferred from railcars to barges or ships to continue the journey to power plants located to the north or further east.[69]

In addition, the Illinois EPA has conducted its own assessment in response to this comment, for the cost for the proposed facility to use Powder River Basin coal. The cost of Powder River Basin coal predicted by this assessment, at $65 per ton, results in a cost-effectiveness value for control of SO_2 emissions of $43,500 per ton of emissions that is avoided.[70] **This cost is excessive and supports rejection of the use of**

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[68] The solid fuel-fired boiler proposed by MGP is not able to operate without a scrubber. This is because it is part of a new facility subject to BACT under the PSD rules. As such, MGP would still be required equip the proposed solid fuel-fired boiler with a scrubber for emissions SO_2 even if it used Powder River Basin coal. The principle savings to MGP that would accompany use of Powder River Basin coal would be the reduction in the variable operational costs for the scrubber as less absorbent material would be needed to control the SO_2 emissions from coal that contains less sulfur.

[69] The major coal terminals in Illinois are located on the Mississippi River, on the Ohio River, and on the Calumet River (Lake Michigan).

[70] Relevant data upon which to estimate the cost of Powder River Basin coal for the proposed facility is available from the information on coal cost assembled by Platts Infostore for the three coal-fired power plants in the Pekin area. This information includes data for seven separate supplies of coal from the Powder River Basin (data for coal from three mines for two of the plants and data for coal from one mine for the third plant). This data supports a cost from the mine for coal, freight on board, at $20.20 per ton, which is 25 percent more than the greatest cost now being paid for a supply of Powder River Basin coal by these three power plants. (It must be expected that MGP would pay significantly more than any of the existing power plants for its Powder River Basin coal.) Similarly, the cost for the initial or "basic transport" of the coal to Illinois, in a manner comparable to the transport of coal from the mine to the existing power plants, would be $25.08 per ton, which is 25 percent more than the greatest cost for transportation now being paid by a power plant. Finally, MGP would experience an additional transportation cost for the intermediate handling for its coal, which reasonably could be equal to the initial transportation cost, or $25.08 per ton. However, as MGP has represented an additional transportation cost of $20 per ton, as previously discussed, the cost for the storage and handling of coal at the intermediate terminal and subsequent transport to the MGP facility is presumed to only be $20 per ton. This results in an overall cost to MGP for Powder River Basin coal of $65.28 per ton ($20.20 + $25.08 + $20.00 = $ 65.28.) Expressed in dollars per mmBtu, the cost of Powder River Basin coal, $3.84 per mmBtu, would be significantly higher than local Illinois coal, at $2.17 per mmBtu.

In determining the cost-effectiveness of the use of Powder River Basin coal, it is also appropriate to account for the reduction in the operating costs of the scrubber, due to the reduction in the amount of SO_2 that must be controlled, as previously discussed. After accounting for this factor, the net increase in costs for the proposed

Powder River Basin coal as an alternative means to control the emissions of the proposed facility.

33. Additionally, with respect to use of alternative cleaner fuels, the Court in the *Prairie State* decision specifically warned that its decision should not be read as broadly allowing the "redefining" policy to trump the "clean fuels" provision in the Clean Air Act, merely because some changes may be necessary to the plant in order to burn cleaner fuel.[71] In other words, plant design changes necessary to burn cleaner fuel, as well as changes to the applicant's preferences or expectations must be considered so that Congress' command to base BACT limits on clean fuels is given effect. Here, the MGP plant is not a mine mouth plant and will receive coal through delivery—whether high sulfur or low sulfur fuels.

As is obvious from responses to other comments, the Illinois EPA considered the possible use of cleaner fuels. They were rejected based on appropriate consideration, e.g., the economic impacts that would accompany a requirement for use of such a fuel were determined to be excessive so that the use of such fuel was not considered achievable. 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.

At the same time, this comment suggests concern by the commenter that a credible argument could be made that certain requirements related to use of lower-sulfur fuel could in fact act to redefine the source. This is certainly the case. As already discussed, the availability of particular low-sulfur fuels is a relevant consideration in a BACT determination.[72, 73] When evaluating the potential use of coal with a

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facility with Powder River Basin coal would be $5,580,440 ($16,128,000 - $ 9,114,000 - $1,183,600 = $5,850,440). The resulting cost-effectiveness for use of Powder River Basin coal as a possible alternative to control the SO_2 emissions of the proposed facility is $43,498 per ton of SO_2 emissions that would be avoided. ($5,850,440 ÷ 134.5 tons of SO_2 = $43,498/ton).

[71] "Suppose this were not to be a mine-mouth plant but Prairie State had a contract to buy high-sulfur coal from a remote mine yet could burn low-sulfur coal as the fuel source instead. *Some adjustment in the design of the plant would be necessary in order to change the fuel source from high-sulfur to low-sulfur coal… but if it were no more than would be necessary whenever a plant switched from a dirtier to a cleaner fuel the change would be the adoption of a "control technology." Otherwise "clean fuels" would be read out of the definition of such technology*.
[Some passages in the Board's *Prairie State* decision] might be read as merging two separate issues: the difference between low-sulfur (clean) and high-sulfur (dirty) coal as a fuel source for a power plant, and the difference between a plant co-located with a coal mine and a plant that obtains its coal from afar. The former is a difference in control technology, the latter a difference in design (or so the EPA can conclude). We think it is sufficiently clear… that the Board did not confuse the two issues; that it granted the permit not because it thinks that burning low-sulfur coal would require the redesign of Prairie State's plant (it would not), but because receiving coal from a distant mine would require Prairie State to reconfigure the plant as one that is not co-located with a mine, and this reconfiguration would constitute a redesign." *Sierra Club v. E.P.A.*, 499 F.3d 653, 656 (7th Cir. 2007).

[72] **When discussing the consideration of energy impacts in a BACT determination in the NSR Manual, USEPA observes that "The energy impact analysis may also address concerns over the use of locally scarce fuels. The designation of a scarce fuel may vary from region to region but generally a scarce fuel is one which is in short supply locally and can be better used for alternative purposes, or one which may not be reasonably available to the source either at the present time or in the future." NSR Manual, page B.31.**

[73] **In its Order Denying Review of Maui Electric Company, PSD/CSP Permit No. 0067-01-C, PSD Appeal No. 98-2, the USEPA's Environmental Appeals Board (EAB) confirmed that, as applied to cleaner fuels, "The term**

particular properties as a means to control emissions, the continued, long-term availability of a supply of that coal is a relevant consideration. This entails not only the continued existence of mines producing that coal but the presence of a transportation infrastructure that enables such coal to be readily delivered to the source. As applied to the proposed MGP project, this means that consideration of a low-sulfur coal alternative to the coal supply proposed by MGP appropriately focuses on Powder River Basin coal. The Powder River Basin produced over 400 million tons of coal in 2007, all of which was low-sulfur coal. As such, the continued mining of low-sulfur coal from the Powder River Basin is unquestioned. In contrast, the continued operation of any mines in Illinois that currently happen to be mining seams of lower sulfur coal cannot be relied upon on a continuing basis into the future. Moreover, the proposed solid fuel-fired boiler would use at most only 200,000 tons of Illinois coal per year, less than 1.0 percent of the coal now being produced in Illinois. This amount of coal is not sufficient to ensure that the operation of any particular mine continues. The coal mining industry is driven by many factors, notably the demand for coal from power plants that use millions of tons of coal each year. It is also not appropriate for the BACT determination for MGP to require that MGP enter into the coal-mining business to operate its own mine to maintain a fuel supply for the proposed facility, instead of simply purchasing coal that is commercially available.

The location of the Powder River Basin and the manner in which Powder River Basin coal is transported to Illinois also mean that "infrastructure" for handling Powder River Basin coal is a relevant consideration in the BACT determination for the proposed facility. That is, for Powder River Basin coal to be determined to be an available alternative to control emissions of the proposed facility there must be a practical means to transport and deliver Powder River Basin coal to the proposed facility. As MGP's Pekin plant is not large enough for a loop track to handle a unit train on-site, this necessarily means consideration of some form of intermediary facility that would handle the transfer of coal for the proposed facility. As with the supply of coal, it is not appropriate for the BACT determination for the proposed facility to require that MGP enter into the coal transfer business with the construction and operation of its own coal terminal to maintain a fuel supply for the proposed facility. Rather, it is appropriate for the BACT determination to consider and rely upon existing terminals that could potentially serve the proposed facility. It is not appropriate to assume that an independent entrepreneur will develop a new rail or barge coal terminal in central Illinois, closer to Pekin, in response to the possible business opportunity that might be present from MGP's proposed facility.

Finally, the general circumstances with regard to availability and transport of coal also pose a fundamental question whether requiring MGP to use coal for the proposed facility other than Illinois coal that is available locally would constitute an

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'available' is used in step two of the Draft Manual's guidelines to refer to whether the technology "can be obtained by the applicant through commercial channels or is otherwise available with the common sense meaning of the term."

The EAB made a similar finding in its Order Denying Review in Part and Remanding in Part for Hawaii Electric Light Company, PSD/CSP Permit No. 0007-01-C, PSD Appeal Nos. 97-15 through 97-23.

inappropriate "redefining of the proposed source" under the PSD rules. In this regard, MGP is proposing a facility at a plant that is located in a region in which coal is mined. It has proposed to construct a facility that would be designed to fire coal that is available locally. This reasonably assures a reliable supply of coal for the operation of the proposed facility without requiring reliance on coal that would have to be transported 1,000 miles to the proposed facility. This is the same decision about coal supply that has been made by sources in Illinois with coal-fired boilers other than coal-fired power plants, including sources with boilers equipped with scrubbers. While Powder River Basin coal is commonly used by Illinois' coal-fired power plants, the economically available coal for use at manufacturing facilities and institutions in Illinois is locally available coal from the Illinois Basin.

34. Carbon dioxide (CO_2) is a pollutant subject to regulation under the Clean Air Act, but the draft permit would not set BACT limits for CO_2. CO_2 is regulated under the Clean Air Act pursuant to Section 821(a) of the Clean Air Act Amendments of 1990, which directed USEPA "to promulgate regulations" requiring that sources covered by Title IV of the Clean Air Act monitor and report their CO_2 emissions.[74] In 1993, USEPA adopted the required regulations for monitoring and reporting CO_2 emissions under 40 CFR Part 75.[75] (*See* 58 FR 3590, January 11, 1993). The plain language and structure of the Clean Air Act, regulations adopted under the Act, as well as USEPA's prior interpretations, confirm that the monitoring and reporting requirements applicable to CO_2 emissions constitute "regulation" within the meaning of Section 165 of the Act.[76] The Illinois EPA's failure to

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[74] Section 821(a) of the Clean Air Act Amendments of 1990 provides "Monitoring. – The Administrator of the Environmental Protection Agency shall promulgate regulations within 18 months after the enactment of the Clean Air Act Amendments of 1990 to require that all affected sources subject to the Title V of the Clean Air Act shall also monitor carbon dioxide emissions according to the same timetable as in Sections 511(b) and (c). The regulations shall require that such data shall be reported to the Administrator. The provisions of Section 511(e) of Title V of the Clean Air Act shall apply for purposes of this section in the same manner and to the same extent as such provision applies to the monitoring and data referred to in Section 511." 42 USC 7651k note; Public Law 101-549; 104 Stat. 2399.

[75] USEPA's regulations for CO_2 emissions pursuant to Section 821 require emissions monitoring (40 CFR 75.1(b), 75.10(a)(3) and 75.33), recordkeeping for emissions (40 CFR 75.57), and reporting of emissions to USEPA, (40 CFR 75.60 – 75.64). 40 CFR 75.5 prohibits operation in violation of these requirements and provides that a violation of any applicable provision in 40 CFR Part 75 is a violation of the Clean Air Act. USEPA has consistently treated these regulations as regulation under the Clean Air Act. It is not reasonable to interpret the term "subject to regulation" to exclude regulations that are enforceable by USEPA through the various enforcement provisions of the Clean Air Act.

[76] A basic canon of statutory interpretation is that words should be given their plain meaning, which is controlling over other agency interpretations. *Lamie v. United States Tr.*, 540 U.S. 526, 534 (2004); *Chevron v. NRDC*, 467 U.S. 837, 842-843 (1984). The Supreme Court has already found that information gathering, recordkeeping, and reporting of emissions are within the conventional understanding of "regulation." *Buckley v. Valeo*, 424 U.S. 1, 66-68 (1976).

Furthermore, the structure of the Clean Air Act shows Congress intended BACT to apply to the broadest category of pollutants. Congress expressly required a BACT limit for "any pollutant subject to regulation" under the Act. 42 U.S.C. § 7475(a)(4). The term "regulation" within Section 165(a)(4) should be presumed to mean the same thing as "regulation" in Section 821, where Congress addressed monitoring and reporting for CO_2 emissions. Refer to *Commissioner of Internal Rev. v. Lundy*, 516 U.S. 235, 249-50 (1996), which found that where Congress uses the same word in two sections of the same act, it is presumed to have the same meaning in both sections.

In contrast, where Congress specifically meant a limit on the quantity of emissions, Congress did so using terms other than "subject to regulation," i.e., "emission limit" or "emission standard" Refer to 42 USC 7602(k) (defining "emission limitation" and "emission standard"); *Alabama Power Co. v. Costle*, 636 F.2d 323, 403-06 (D.C. Cir. 1979) (holding that BACT applies BACT to pollutants "subject to regulation," which is broader than pollutants for which ambient air quality standards are set and broader than pollutants for which performance standards are set under Section 111 of the Clean Air Act).

include BACT limits for emissions CO_2 from the proposed facility is clearly erroneous.

Carbon dioxide (CO_2) is not a pollutant that is regulated under the PSD program, as recently clarified in formal actions by USEPA. USEPA does not consider that the monitoring and reporting of CO_2 emissions pursuant to Section 821 of the Clean Air Act Amendments of 1990 and certain provisions under 40 CFR Part 75 is sufficient for CO_2 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.[77] Notice of this determination was subsequently provided by a notice in the Federal Register.[78] 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 of emissions. The memorandum finds that the data gathering requirements for CO_2 emissions promulgated under Title IV of the Clean Air Act does not compel the conclusion that Congress meant for CO_2 to become a regulated pollutant under the PSD program. USEPA identified several policy concerns with construing the Clean Air Act in this manner, including the undesirable effects such an interpretation would pose for information gathering activities and the administration of the PSD program.

The applicability of this memorandum is broad and unambiguous, as it also indicates that it applies to "all PSD permitting actions by EPA regions (and delegated States that issue permits on behalf of EPA Regions)." As such, the Illinois EPA, as a permit authority that administers the federal PSD program in a delegated capacity, is obliged to implement USEPA's interpretation. While the current USEPA Administrator, Lisa Jackson, announced on February 18, 2009, that USEPA has granted a petition filed by Sierra Club and other parties for reconsideration by USEPA of its December interpretative memorandum, she did not stay the effect or validity of the interpretative memorandum.[79] In addition, the USEPA, under the leadership of Administrator Jackson, has begun a separate legal procedure whereby emissions of CO_2 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 CO_2, threaten the public health and welfare of current and future generations.[80]

Various arguments relating to this premise of this comment, i.e., that requirements for monitoring and reporting of CO_2 emissions make CO_2 subject a regulated

[77] Memorandum, December 18, 2008, by Stephen L. Johnson, Administrator of the USEPA, entitled *EPA's Interpretation of Regulations that Determine Pollutants Covered By Federal Prevention of Significant Deterioration (PSD) Permit Program.*

[78] Notice of this interpretative memorandum was published in the Federal Register on December 31, 2008, i.e., Notice of issuance of the Administrator's Interpretation. 73 FR 80,300 (December 31, 2008).

[79] Subsequently, on April 17, 2009, Administrator Lisa Jackson announced that USEPA is proposing to issue a finding that CO_2 is a pollutant that is present in the atmosphere in concentrations that threatens public health and welfare. Adoption of this finding by USEPA would set in motion a process whereby CO_2 would begin to be regulated under various provisions of the Clean Air Act.

[80] The USEPA's *Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases* under the Clean Air Act was published in the Federal Register on April 24, 2009 (74 FR 18886).

pollutant subject to the PSD program, were also considered by the USEPA's Environmental Appeals Board (EAB) in an appeal by the Sierra Club of a PSD Permit issued by USEPA, Region 8, to the Deseret Power Electric Cooperative for a new generating unit. In its ruling in *Deseret Power* [PSD Appeal No. 07-03, *Order Denying Review in Part and Remanding in Part*, issued November 13, 2008], the EAB rejected the Sierra Club's contention that the statutory phrase "subject to regulation" was sufficiently clear and unambiguous as to compel USEPA to impose a CO_2 BACT limit under the PSD program. However, the EAB also rejected USEPA's position in that case that it could not impose a CO_2 BACT limit by reason that its historical interpretation of this phrase precluded such a limit. The EAB remanded the issue to USEPA Region 8 with instructions to reconsider whether a CO_2 BACT limit should be developed "in light of the Agency's discretion to interpret, consistent with the CAA [Clean Air Act], what constitutes a 'pollutant subject to regulation under the Act'." [PSD Appeal No. 07-03, *slip opinion at page 64*]. The issuance of an interpretative memorandum by USEPA Administrator Johnson on December 18, 2008, is directly responsive to the EAB's ruling in the Deseret Case.

Incidentally, the USEPA interpretative memorandum is consistent with Section 821 of the Clean Air Act Amendments of 1990. Section 821 is entitled "Information Gathering on Greenhouse Gases Contributing to Global Climate Change." The regulations adopted by USEPA pursuant to Section 821 of the Clean Air Act Amendments of 1990, which require collection of data for CO_2 emissions from power plants, do not demonstrate an intent by USEPA to regulate CO_2 under the PSD program. Rather, they merely reflect compliance with the explicit statutory directive of Congress that certain sources begin collecting data for CO_2 emissions and reporting that data to USEPA. If Congress had intended that CO_2 be treated as a pollutant subject to the PSD program, it would have certainly indicated that in Section 821. Instead, Congress only provided that certain provisions of the Clean Air Act related to enforcement were to apply to the required collection and submittal of emission data for CO_2.[81] It did not specify that the provisions of the Clean Air Act for PSD were to also be applicable.

35. CO_2 is also a regulated pollutant for purposes of PSD because the USEPA has approved certain revisions to state implementation plans (SIPs) that include provisions that regulate CO_2 emission. Pollutants regulated by an approved SIP are regulated under the Clean Air Act. In particular, USEPA recently approved a revision to the State of Delaware's SIP that includes provisions that establish CO_2 emission limits and operating requirements, CO_2 record keeping and reporting requirements, and CO_2 emissions certification, compliance and enforcement obligations for stationary engine generators. (73 FR 23,101 April 29,

[81] Section 821 of the Clean Air Act Amendments provides that "the provisions of section 511(e) of title V of the Clean Air Act shall apply for purposes of this section in the same manner and to the same extent as such provision applies to the monitoring and data referred to in section 511." As there is no Section 511 in Section V of the Clean Air Act, this reference is reasonably considered to refer to Section 412(e) in Title IV of the Clean Air Act. (Section 412(e) makes it unlawful to operate a subject source without monitoring and reporting of its emissions of SO_2 and NO_x (and opacity) in accordance with applicable USEPA regulations.) This further action in Section 821 providing for enforceability of the data gathering requirements for CO_2 emissions would not have been necessary if Congress had been establishing emission limitations or emissions standards for CO_2.

2008). Furthermore, on April 29, 2008, among other regulatory provisions, USEPA approved emission standards for CO_2. Regulation 1144, which has now been adopted into Delaware SIP at 40 CFR 52.420, provides that its purpose is to "ensure that emissions of… carbon dioxide (CO_2) from *stationary generators* in the State of Delaware do not adversely impact public health, safety, and welfare." Del. Regulation No. 1144 § 1.1. [82] Once incorporated into Delaware's SIP, these CO_2 limits are enforceable under the Clean Air Act pursuant to Section 113 of the Act. There was no question that USEPA was approving CO_2 emission limits into regulations under the Clean Air Act.[83]

These comments do not demonstrate that CO_2 is a regulated pollutant for purposes of PSD in Illinois, much less in Delaware. In this regard, it is noteworthy that USEPA's recent interpretative memorandum rejects the position put forth in this comment. The USEPA's memorandum 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.[84] 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. This comment does not address this obvious difference in the nature of SIP revisions and emission standards adopted by USEPA, much less support its premise that coincidental action by USEPA in approving a SIP submittal is sufficient to create a "regulated air pollutant" as a matter of national law.

The actions by USEPA cited in these comments also do not demonstrate thoughtful action by USEPA to treat CO_2 as a regulated pollutant for purposes of PSD, so as to rebut the recent direct action by Administrator Johnson of the USEPA. As stated in

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[82] Regulation 1144 limits emissions of CO_2 to 1900 lbs/MWh for existing distributed generators, 1900 lbs/MWh for new distributed generators, and 1,650 lb/MWh for new distributed generators installed on or after January 1, 2012. Regulation No. 1144: Control of *Stationary Generator* Emissions, §3.2.

[83] When reviewing Delaware Regulation 1144 for inclusion in Delaware's SIP, USEPA Region 3 stated, "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.… Regulation No. 1144 adopted by the State of Delaware will result in the control of NOx, NMHC, PM, SO2, CO, and CO_2 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, Engineer, Air Quality Planning Branch, USEPA Region 3, Re: Technical Support Document – Delaware; Regulation No. 1144 – Control of Stationary Generator Emissions (January 25, 2008).

[84] In general, USEPA's approval of provisions in State SIPs is a different legal process from the direct adoption of standards by USEPA under its independent authority under the Clean Air Act. The USEPA's approval of the provisions in State SIPs is a mechanism whereby USEPA formally reviews the adequacy of state rules and other measures that have been adopted by individual states to fulfill their obligations under the Clean Air Act. As particular state provisions are found adequate, they are approved by USEPA. If the approved state measure is one that is appropriate for enforcement, such as an emission standard, USEPA's approval of the measure as part of the state's SIP also allows for enforcement of the measure by USEPA under federal law. This is different from the regulatory process whereby USEPA unilaterally adopts National Ambient Air Quality Standards or federal New Source Performance Standards for various pollutants under its direct authority under the Clean Air Act. It is this latter form of regulation that creates or defines the scope of pollutants that are considered "subject to regulation" for purposes of the PSD program.

the USEPA's documentation for the cited Delaware SIP revision, USEPA approved this SIP revision as it would assist in achieving compliance with the 8-hour ozone NAAQS. There is no evidence that USEPA approved this SIP revision as a means to address emissions of greenhouse gases. This action also was not accompanied by a reasonable opportunity for the public to comment on whether it was appropriate for these rules to be approved as part of Delaware's SIP as a means to control emissions of greenhouse gases.[85] Moreover, Delaware has a "SIP approved" PSD program. As such, actions to include additional pollutants under its state-based PSD programs would necessitate rulemaking by Delaware to revise its state PSD program and SIP for the PSD Program, which has not occurred. (Incidentally, these actions would trigger thoughtful action by USEPA to consider whether to approve such provisions as part of a SIP revision.) Finally, 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.

36. Requirements to monitor CO_2, emissions are also included in various state implementation plans. For example, CO_2 emissions are regulated under Wisconsin's SIP. Wisc. Adm. Code Sections NR 438.03(1)(a) requires reporting of pollutants listed in Table 1 (including CO_2), and NR 439.095(1)(f) provides that Phase I and phase II acid rain units "shall be monitored for . . . carbon dioxide . . ." These rules were adopted by USEPA as part of Wisconsin's SIP at 40 CFR 52.2570 (c)(70)(i) and (c)(73)(i)(i), respectively.

The cited actions do not demonstrate considered judgment by USEPA to treat CO_2 as a regulated air pollutant, so as to rebut the recent determination by former USEPA Administrator Johnson.

Moreover, with respect to reporting of CO_2 emissions pursuant to Wisconsin's SIP and Wisc. Adm. Code NR 438, it is unclear that the USEPA actually approved provisions dealing with CO_2 as part of Wisconsin's SIP. The cited SIP approval addresses the version of Wisc. Adm. Code NR 438 promulgated by Wisconsin in May 1993 and does not address the current version of this rule.[86] In addition, the provision in Wisc. Adm. Code NR 439.095(1)(f) addresses certain measurements that must be conducted for O_2 (oxygen) or CO_2 in conjunction with emissions measurements for NO_x or SO_2 to normalize those measurements. If CO_2 were to be

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[85] The notice for the USEPA's proposed approval of Delaware Regulation No. 1144 makes no mention, and thus did not provide any notice that certain emission standards for CO_2 were included in Regulation No. 1144. The notice for this approval (73 FR 11845, March 5, 2008) indicates that the subject of the regulations is emissions that contribute to ambient levels of ozone and particulate matter. "EPA is proposing to approve the Delaware SIP revision for Regulation No. 1144—Control of Stationary Generator Emissions submitted on November 1, 2007. This regulation will help ensure that the air emissions from new and existing stationary generators do not cause or contribute to the existing air quality problems with regard to ground-level ozone and fine particulate matter, thereby adversely impacting public health, safety and welfare. EPA is soliciting public comments on the issues discussed in this document. These comments will be considered before taking final action."

[86] In the action cited by this comment, USEPA approved the version of Wisc. Adm. Code NR 438 published in the Wisconsin Register in May 1993. This is not the current version of Wisc. Adm. Code NR 438. The most recent version of Wisc. Adm. Code NR 438 was promulgated on December 31, 2005.

considered a pollutant pursuant to this provision, it would lead to the absurd result that oxygen must also be considered a pollutant for purposes of the PSD program.

37. CO_2 is a regulated pollutant for purposes of PSD because the Illinois EPA (like most other state permitting authorities) has included monitoring and reporting requirements for CO_2 emissions in operating permits issued to sources, as required by Sections 39.5(7)(b) and 17(m) of Illinois' Environmental Protection Act. For example, refer to the Construction Permit/PSD Approval for the power plant proposed by Prairie State Generating Company, LLC.[87] The inclusion in Illinois' Title V permits of the requirements of 40 CFR Part 75 for monitoring, recordkeeping and reporting of CO_2 emissions is consistent with the Title V program, 40 CFR 70.2, which defines "applicable requirement" to include requirements in regulations promulgated under Title IV of the Clean Air Act. The inclusion of these requirements in Title V permits further makes the CO_2 monitoring, recordkeeping and reporting requirements enforceable pursuant to the Clean Air Act.[88]

The cited actions by the Illinois EPA do not demonstrate considered judgment by USEPA to treat CO_2 as a regulated air pollutant for purposes of PSD, so as to rebut the recent ruling by Stephen Johnson, Administrator of the USEPA. They also do not provide an alternative basis to show that emissions of CO_2 are regulated pursuant to the Clean Air Act. As clearly indicated in this comment, the provisions of 40 CFR 75 are simply "carry-over" requirements of federal regulations that must be included in Clean Air Act Permit Program (CAAPP) permits issued to sources in Illinois that are subject to the federal Acid Rain Program. In addition, these provisions are included in Illinois' CAAPP permits pursuant to Illinois' Environmental Protection Act.[89] Finally, the provisions of 40 CFR Part 75 are directly enforceable under the Clean Air Act independently of whether or not they have been included in a CAAPP permit issued by the Illinois EPA.

In addition, examination of the relevant provisions of Title V of the Clean Air Act shows that Title V is consistent with the USEPA's position that CO_2 is not a regulated pollutant for purposes of the PSD program. Title V acknowledges that pollutants can be subject to different classes of requirements under the Clean Air Act. For example, refer to Section 502(b)(5), which provides that a permitting authority have must adequate authority in a Title V permit to assure compliance "… with each applicable standard, regulation or requirement under this Act."

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[87] The construction permit issued for this proposed plant (ID No. 189808AAB) requires that it comply with all applicable requirements in 40 CFR Part 75. (Refer to Section 3 and Attachment 3 of this permit.)

[88] Refer to 42 USC Sections 7413(a)(1) (enforcement authority for violations of any permit), (a)(3) (providing for enforcement of any requirement of a Title V permit), (b) (civil enforcement of any requirement in a permit and any requirement pursuant to Title V), (c)(1) (criminal enforcement for any violation of any requirement of a Title V permit), (d)(1)(B) (administrative penalties for violating any requirement of Title V), 7604(f)(4) (citizen suit enforcement of any standard, limitation, or schedule established in a Title V permit).

[89] **The Clean Air Act Permit Program (CAAPP) is the operating permit program developed by Illinois to fulfill the mandate of Title V of the Clean Air Act. The authority for the CAAPP is state law, at Section 39.5 of Illinois' Environmental Protection Act.**

38. A Georgia court found that CO_2 is "subject to regulation" under the Clean Air Act. *Friends of the Chattahoochee, Inc., et al. v. Couch, et al.* ("Longleaf"), Docket No. 2008CV146398, Superior Court of Fulton County, Georgia, (Final Order, June 30, 2008).

The cited decision by a Georgia state court does not govern in this matter as the decision was not made by a federal court. It also precedes the recent interpretative memorandum by Stephen Johnson, Administrator of the USEPA confirming that CO_2 is not a regulated air pollutant for purposes of PSD. Accordingly, the Longleaf decision cannot be considered to rebut the subsequent direct statement by USEPA on this subject and the USEPA's associated legal analysis.

39. USEPA has also regulated emissions of CO_2 in its regulations for control of emissions from municipal solid waste (MSW) landfills adopted under Section 111 of the Clean Air Act. Control of "MSW landfill emissions" is required by 40 CFR 60.33c. Landfill gas emissions include CO_2, as 40 CFR 60.751 defining "landfill emissions" as all "gas generated by the decomposition of organic waste deposited in an MSW landfill or derived from the evolution of organic compounds in the waste." (63 FR 2154-01, Jan. 14, 1998)[90] In other words, landfill gases are regulated, and CO_2 is a landfill gas—therefore, CO_2 is a regulated pollutant.

The argument made in this comment does not demonstrate that emissions of CO_2 have been regulated by USEPA under the Clean Air Act. In particular, in the cited regulations, USEPA has not adopted regulations that limit the rate or amount of CO_2 emissions from landfills. In its various regulations addressing emissions from landfills, the USEPA has set emission standards and control requirements for emissions of organic compounds and hazardous air pollutants. The fact that other pollutants, e.g., CO_2, may also be present in the emissions of landfills does not mean that the emissions of those other pollutants have been regulated.

40. Pollutants regulated by state implementation plans (SIPs) approved by USEPA are regulated under the Clean Air Act. In addition to CO_2, it is also important that emissions of nitrous oxide (N_2O), which has a global warming potential of 296 times that of CO_2[91] be controlled as a greenhouse gas. N_2O is regulated in at least Wisconsin's SIP and therefore is regulated under the Clean Air Act.[92] Once a state rule is approved by USEPA as a part of a SIP, it is subject to regulation under the Clean Air Act.[93] Therefore, BACT limits are also required for the emissions of N_2O from the proposed facility.

[90] USEPA has also identified landfill emissions as including methane and CO_2 in other documents, for example, USEPA, Office of Air Quality Planning and Standards, *Air Emissions from Municipal Solid Waste Landfills—Background Information for Final Standards and Guidelines*, EPA-453/R-94-021, December 1995.
[91] *See* Climate Change 2001: Working Group I: The Scientific Basis, available at http://www.grida.no/climate/ipcc_tar/wg1/248.htm.
[92] *See* Wis. Stat. §§ 285.60 (requiring air permits for all sources not otherwise exempted), 285.62(1); Wisc. Adm. Code NR 407.05, Table 3 (requiring permit application to include N_2O if more than 2,000 lbs/year). N_20 is also regulated under Wisc. Adm. Code NR 438.03(1)(a), adopted as part of Wisconsin's SIP at 40 CFR 52.2570(c)(70)(i).
[93] Refer to *General Motors Corp. v. U.S.*, 496 U.S. 530, 540 (1990) "The language of the Clean Air Act plainly states that USEPA may bring an action for penalties or injunctive relief whenever a person is in violation of any requirement of an "applicable implementation plan." Section 113(b)(2) of the Clean Air Act.

As is the case for CO_2, approval of state rules that address emissions of N_2O as part of a state's SIP does not constitute a basis for the Illinois EPA to impose a BACT limit for N_2O in the construction permit for the proposed facility. Such actions by USEPA do not reflect a considered judgment by USEPA to treat or consider N_2O emissions as a pollutant "subject to regulation" for purposes of PSD, a conclusion that is supported by USEPA's recent interpretative memorandum.

41. MGP does not adequately explain how it derived the proposed BACT limit for NO_x emissions from the coal-fired boiler, 0.1 lb/mmBtu. The only explanation appears to be the following statement from MGP's consultants: "Due to the fact that the MGP operations requires [sic] frequent load changes, the requested BACT NO_x emissions limit is 0.10 lb/mmBtu . . . ." Letter, December 21, 2007, page 9. This is an inadequate explanation for why the BACT limit was set at 0.1 lb/mmBtu. Certainly it is not consistent with a top-down analysis.

This comment overlooks the bulk of the material in the application addressing NO_x BACT for the proposed boiler, focusing instead on a single sentence in a supplement to the application. The original application submitted on March 2007, included a top-down analysis for NO_x BACT, with an assessment of possible technology alternatives for control of NO_x from the proposed boiler and a listing of NO_x emission limits set for other new coal-fired boilers. It discusses at length (Pages 1-44 through 1-47) why a NO_x BACT limit that addresses all emissions of the proposed boiler, including emissions during periods of startup, shutdown and malfunction, should be set at 0.10 lb/mmBtu and not a lower rate. It reports experience with SCR systems on larger, utility-scale coal-fired boilers on which NO_x emission limits lower than 0.10 lb mmBtu have not been reliably met on such boilers. It also reports on information showing that in practice SCR systems do not meet their design levels of removal efficiency.

42. For the proposed coal-fired boiler, a BACT limit lower than 0.10 lb/mmBtu should be set for NO_x. This is because a BACT analysis must consider transfer technology and such technology's demonstrated effectiveness at other sources. Low NOx burners and SCR technology are typically used at coal fired electric generating units. Numerous existing generating units are achieving NOx emission rates much lower than the 0.10 lb/mmBtu proposed as BACT for the proposed coal-fired boiler. In particular, the four generating units at the W A Parish power plant in Texas achieve 30-day average NO_x emission rates ranging from 0.048 to 0.059 lb/mmBtu.[94] Other coal-fired power plant boilers equipped with SCR systems achieve 30-day average NO_x emission rates ranging from 0.031 to 0.627 lb/mmBtu, 30-day average.[95]

The emission data provided with this comment confirms that SCR is the top control technology option for the proposed solid fuel-fired boiler. However, it does not provide a basis to set a lower NO_x BACT limit for MGP's proposed boiler. Given the

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[94] The W A Parish is the largest fossil fuel fired power plant in the United States. Its four coal-fired electrical generating units, at 650 MW each, are each over 12 times larger than MGP's proposed boiler.

[95] Data for the 2003, 2004 and 2005 ozone seasons for 26 coal-fired generating units equipped with SCR systems (total of 70 data points) shows many highest 30-day rolling average NO_x emission rates during these ozone seasons that are much lower than 0.10 lb/mmBtu.

size of the four coal-fired generating units at the W A Parish power station, with accompanying low operating costs, these units operate as base-load units. Their NO_x emission rates are among the lowest NO_x emission rates of coal-fired generating units in the United States. As such, the NO_x emission data for the W A Parish units cannot be considered to be indicative of the emission rate that is achievable by a much smaller boiler operated at a manufacturing plant. The data for other coal-fired electrical generating units provided with this comment also does not provide a basis to set a lower NO_x BACT limit. This is because the comment does not explain why data from units that are generally much larger than the proposed boiler should be transferable to the proposed boiler or why there is such a range in the NO_x emission rates, so as to allow reliance on this data. The comment then does not identify the specific rate at which the commenter believes that NO_x BACT should be set based on this body of data.[96]

At the same time, as a result of further evaluation in response to this comment and other comments concerning the proposed NO_x BACT limit for MGP's proposed solid fuel-fired boiler, the issued permit includes an additional NO_x BACT limit for this boiler. This second NO_x BACT limit, at 0.080 lb/mmBtu, is lower than the generally applicable limit of 0.100 lb/mmBtu. However, it only applies for periods when the boiler is operating in its normal load range, defined as at least 60 percent load. This is the mode of operation for which the SCR system would be most effective, with flue gas temperature in the ideal range for control of NO_x emissions. It would not include extreme load swings and periods of startup and shutdown, when the boiler will as a matter of course operate at less than 60 percent load. Like the basic NO_x BACT limit of 0.10 lb/mmBtu, which addresses all operation of the boiler, this second NO_x BACT limit would apply as a "30-day average." For this purpose, the same 30-day period would be used except that individual hours when the boiler operates at less than 60 percent load would not be included when calculating the average NO_x emission rate to determine compliance with the limit of 0.080 lb/mmBtu.

Upon further consideration by the Illinois EPA, this second BACT limit is a logical corollary to the basic NO_x BACT limit, which must be set to accommodate all modes of operation of the boiler, including modes that are less ideal for control of NO_x emissions. It follows that a separate BACT limit can be set that only addresses modes of operation of the boiler when NO_x emissions can be more effectively controlled. When approached in this way, a NO_x emission limit can be set for the proposed boiler that is achievable and that is 80 percent of the basic limit, i.e., 0.080 compared to

[96] Assuming for purposes of discussion that the reported data for coal-fired utility boilers is relevant and is properly applied to the proposed coal-fired boiler, this data would not support a NO_x BACT limit lower than 0.10 lb/mmBtu. Even after culling the data to remove data points that presumably represents operation of boilers without an SCR system (four data points that are greater than 0.02 lb/mmBtu), 4 of the remaining 70 data points are above 0.10 lb/mmBtu. This is a significant number of data points (more than 5 percent of the data), which indicates that a NO_x BACT limit set at a level lower than 0.10 lb/mmBtu would not necessarily provide a reasonable margin of compliance so as to be achievable given normal variation in the operation of the boiler and associated NO_x control system. The number of "noncompliant" data points would increase exponentially as the BACT limit was reduced. At 0.08 lb/mmBtu, there would be 9 "noncompliant" data points (more than 12 percent of the data set). At 0.06 lb/mmBtu, there would be 28 "noncompliant" data points (more than 40 percent of the data set).

0.100 lb/mmbtu. This approach is consistent with that used by the Nebraska Department of Environmental Quality for certain new industrial coal-fired boilers in Nebraska.[97]

43. There is no basis to believe that SCR technology cannot achieve at least as stringent a NO_x BACT limit for the MGP boiler merely because the steam will be used in an industrial process in addition to electric generation. Illinois EPA should require MGP to further discuss the reasoning for this limit, including why MGP cannot achieve the same BACT limit as other coal boilers using this same technology, and must make that analysis available for public comment before any permit is issued.

The NO_x emission rates achieved by SCR technology on coal-fired utility boilers are not directly transferable to the solid fuel-fired industrial boiler proposed by MGP. A key factor in the ability of an SCR system to achieve a particular NOx emission rate, in lb/mmBtu, is variability in the operation of the associated emission unit as it affects the temperature and flow rate of the flue gas entering the SCR. This is because SCR relies on a reaction that is facilitated by a catalyst and is highly dependent on the temperature of the flue gas and maintaining the proper reagent injection rate. Accordingly, the performance of an SCR system is affected by the extent of non-ideal operating conditions that will be encountered.

This means that the effectiveness of SCR is affected by the different way that coal-fired utility boilers and industrial boilers operate, which is a result of the different circumstances in which they operate. Coal-fired utility boilers operate as a group, along with other utility units, to supply power to the electrical grid. This collection of generating units, which includes base-load units, cycling units and peaking units, operate in a coordinated manner under the supervision of an "independent system operator" to meet the aggregate demand for electrical power in a region that encompasses thousands or millions of separate power consuming facilities. This acts to stabilize the operating level of the large base-load generating units, which are the units that have generally been equipped with SCR systems.[98] It also means that SCR systems are not installed on utility boilers that routinely operate at low loads. In contrast, the proposed boiler would be a stand-alone boiler. It would be operating to

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[97] On September 8, 2006, the Nebraska Department of Environmental Quality set NO_x BACT for a new 1500 mmBtu/hr coal-fired boiler proposed by Cargill for its corn wet milling plant in Blair, Nebraska, as 0.08 lb/mmBtu, 30-day average, when the boiler operates at 70 percent load or more and 120 lbs/hr, 30-day average when the boiler operates at less than 70 percent load. Permit No. CP06-0008, Condition XIII(L)(4). At 70 percent load, the break point between the two BACT limits, hourly emissions of 120 pounds are equivalent to an emission rate of 0.114 lb/mmBtu. (120 ÷ (0.7 x 1500) = 0.114.)

On September 11, 2006, the Nebraska Department of Environmental Quality set NO_x BACT for a new 382 mmBtu/hr coal-fired boiler proposed by Ag Processing for a soybean processing plant in Hastings, Nebraska, as 0.08 lb/mmBtu, 30-day average, when the boiler operates at 70 percent load or more and 30.56 lbs/hr, 48-hour rolling average, when the boiler operates at less than 70 percent load. Permit No. CP05-0050, Condition 3.EP 401.I. At 70 percent load, hourly emissions of 30.56 pounds are equivalent to an emission rate of 0.114 lb/mmBtu. (30.56 ÷ (0.7 x 382) = 0.114.)

[98] SCR systems are generally installed on larger generating units because this provides the greatest reduction in NOx emissions while minimizing cost. This is because of the greater amounts of NO_x available to be controlled by the SCR system and the accompanying savings in construction costs and operating costs that are then possible if the SCR systems do not need to be installed on as many generating units.

meet the specific steam needs of only the MGP plant.[99] As the plant's steam needs change, the operating level of the proposed boiler would directly be affected. At times, this would entail operation of the boiler at low load, as only certain portions of the plant are in operation.

In summary, it is not the fact that steam from the proposed boiler will be used at an industrial facility, as suggested by this comment, that affects the performance of SCR in controlling the proposed boiler's NO_x emissions. Rather, it is the effects of frequent load changes and low-load operation of the boiler, which will occur as the boiler would serve a single plant with several manufacturing processes, that will affect the control of NOx emissions achieved with SCR technology. These circumstances have been adequately explained, as the differences in the function and manner of operation of the proposed boiler and utility boilers that are equipped with SCR systems are readily apparent. This necessitates a higher NO_x BACT limit for the new boiler compared to those set for new utility boilers, which as previously discussed, routinely occurs for proposed new coal-fired boilers at industrial or manufacturing plants.

44. A lower BACT limit should be set for the NO_x emissions of the proposed coal-fired boiler. The NO_x emissions from the proposed boiler would be controlled by low-NO_x burners and an SCR system. Conservatively assuming a high boiler outlet rate of 0.4 lb NO_x/mmBtu, an SCR system can achieve a 90 percent reduction. This yields a rate of 0.04 lb/mmBtu, which is much lower than the BACT limit proposed in the draft permit, 0.1 lb/mmBtu.

This comment does not provide a reasoned basis to set a lower BACT limit for the proposed solid fuel-fired boiler. This is because it is not accompanied by any support for the presumption that an SCR system can achieve a 90 percent reduction in NO_x emissions when applied to the proposed boiler.[100] First, 0.4 lb NO_x/mmBtu is not a "high" boiler outlet emission rate, such that one should rely on achieving a NO_x reduction of 90 percent by SCR. Rather, 0.4 lb NO_x/mmBtu is a moderate NO_x emission rate, for which an SCR system should be expected to provide only a moderate further reduction in NO_x emissions.[101] Second, this comment is

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[99] "Boiler operation at reduced loads decreases the gas flow rate. At reduced gas flow rates, the economizer outlet gas temperature decreases because boiler heat transfer surfaces absorb more heat from the flue gas. Typical SCR systems tolerate temperature fluctuations of ± 200°F (± 93 °C). At low boiler loads, however, the temperature can decrease below the optimum range. For example, a coal-fired utility boiler has an economizer exit flue gas temperature of 690 °F (366 °C) at 100% load, but only 570 °F (300 °C) at 50% load. For low-load operations, an economizer bypass can be used to raise the flue gas temperature. An economizer bypass diverts part of the hot flue gas from within the economizer through a bypass duct and mixes it with the relatively cooler flue gas exiting the economizer. An economizer feedwater bypass also raises the flue gas temperature. The use of an economizer bypass results in less energy transfer to the feedwater for steam generation, consequently, there is a small reduction in boiler efficiency. Lower boiler efficiencies require more fuel to be burned to meet the required boiler steam output." USEPA, *Air Pollution Control Cost Manual.* Sixth Edition, USEPA, Office of Air Quality Planning and Standards.

[100] In its *Air Pollution Technology Fact Sheet: Selective Catalytic Reduction (SCR)*, USEPA states that "SCR is capable of NOx reduction efficiencies in the range of 70% to 90%."

[101] As a general matter, a high uncontrolled NO_x emission rate should be considered to be a rate higher than 0.6 lb/mmBtu, as present on an existing cyclone-fired utility boiler that is not amenable to significant reduction in NO_x emissions with the retrofit of low NO_x burner technology and combustion modifications. Even for such

contradicted by the information that was submitted on the NO_x emissions of coal-fired utility boilers equipped with SCR systems. That data showed considerable variability in emissions, with NO_x emissions consistently above 0.04 lb/mmBtu.

In addition, the boiler outlet NOx emission rate for the proposed solid fuel-fired boiler, as indicated in MGP's application will only be 0.3 lb/mmBtu, 30 day average.[102] With this outlet emission rate, the performance of the SCR system should be based on the lower end of the efficiency range of SCR, i.e., 70 percent, for a BACT limit that addresses all operation of an industrial boiler, including startup, shutdown and malfunction and low-load operation. After considering a margin of compliance to address normal variation in operation, this yields a NO_x BACT limit of 0.10 lb/mmBtu, 30-day average,[103] as contained in both the draft and issued permit. For a NO_x BACT limit that only applies for the normal load range of the boiler, the performance of the SCR system should be based on the middle of the efficiency range of SCR, i.e., 75 percent. This yields the additional BACT limit of 0.08 lb/mmBtu, 30-day average, as is also present in the issued permit.[104]

45. A lower BACT limit should be set for NO_x for the proposed coal-fired boiler. Low NOx burners and SCR technology, as used at coal-fired electric generating units, have been the basis for BACT limits at 0.05 lb/mmBtu over short averaging periods (i.e., 24 hours).

This comment does not demonstrate that a NO_x BACT limit of 0.05 lb/mmBtu is appropriate for the proposed boiler. The proposed boiler is not an electrical generating unit, as already discussed. The information submitted on the NO_x emissions of coal-fired utility boilers equipped with SCR systems, as previously discussed, also showed NO_x emissions consistently above 0.05 lb/mmBtu, with considerable variability in NO_x emission rates.

Moreover, while NO_x BACT limits may have been set at 0.05 lb/mmBtu, 24-hour average, for certain proposed coal-fired utility generating units, as claimed by this comment, higher BACT limits are also being set.[105] This confirms that the case-by-

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boilers, SCR systems have not been found to consistently comply with an emission limit of 0.04 lb/mmBtu, 30-day average, including startup, shutdown and malfunction. In this regard, there is a difference between at times, or even routinely, meeting a particular emission rate and being required to comply with that emission rate as BACT. A BACT emission rate must be set at a level that is achievable and can be met considering normal variation in the emissions of a unit and the performance of associated emission control measures.

[102] MGP Application, initial submittal, received March 22, 2007, pages 1-44 and 1-45.

[103] 0.30 lb/mmBtu x (1 – 70 %/100 %) x 110 % = 0.099, ≈ 0.10 lb/mmBtu.

[104] 0.30 lb/mmBtu x (1 – 75 %/100 %) x 110 % = 0.0825, ≈ 0.080 lb/mmBtu.

[105] This comment does not identify a specific project for which a NO_x BACT limit of 0.05 lb/mmBtu, 24-hour average, has been set. Accordingly, information on recent BACT determinations for NO_x for significant projects involving coal-fired boilers follows. This information shows that permitting authorities are setting NO_x BACT limits at levels higher than 0.05 lb/mmBtu, 24-hour average.

On July 31, 2008, USEPA issued a PSD permit for the proposed Desert Rock Energy Facility, a coal-fired utility boiler with a nominal capacity of 6,810 mmBtu/hr, a unit almost 14 times larger than the proposed MGP boiler. For the first 60 months of operation of the unit, the "NO_x Optimization Period," the permit sets NO_x BACT as 0.060 lb/mmBtu, 24-hour average, and 0.050 lb/mmBtu, 365-day rolling average. Following the NO_x Optimization Period, the NO_x BACT limits will lower to 0.0385 lb/mmBtu, 365-day rolling average, 0.050 lb/mmBtu, 30-day rolling average, and 0.060 lb/mmBtu, 24-hour average, unless compliance with such limits is

case determinations of BACT by permitting authorities may differ depending on the nature of a particular project and the format of the NO_x limits selected by the permitting authority. For the solid fuel-fired boiler proposed by MGP, the combination of two NO_x BACT limits, one at 0.08 lb/mmBtu, 30-day average, and the other at 0.10 lb/mmBtu, 30-day average, is considered to reflect the NO_x emission rates that are achievable by the boiler given that it would be the primary boiler serving a single manufacturing plant.

46. Condition 2.1.2(b) of the draft permit would provide that the SO_2 BACT limits would not be applicable for the first 18 months of operation of the coal-fired boiler. BACT must be immediately applicable.

This inadvertent error in Condition 2.1.2(b) of the draft permit has been corrected in the issued permit. The permit sets two SO_2 BACT limits for the proposed solid fuel-fired boiler, one in terms of lbs/mmBtu and the other in terms of control efficiency. The first SO_2 limit, 0.185 lb/mmBtu, is immediately applicable. The other limit, which requires at least 98 percent control efficiency if the boiler's SO_2 emission rate is more than 0.140 lb/mmBtu, becomes effective 18 months after the initial startup of the boiler. It is appropriate that this second limit should be phased-in because it addresses a second, more complex aspect of control of the SO_2 emissions of the boiler. This is because this limit addresses control efficiency, so involves not only the actual SO_2 emission rate of the boiler, which would be directly monitored, but also the potential uncontrolled SO_2 emission rate of the boiler, which would have to be determined from the sulfur and heat content of the fuel being fired in the boiler.

47. In 2006, according to the most recent Illinois Annual Air Quality Report, Pekin had the highest ambient SO_2 levels in Illinois.[106] The SO_2 pollution in Pekin comes from Aventine Renewable Energy, another ethanol plant located next to MGP, and three coal-fired electric power plants along the Illinois River. In total, these plants emitted 84,530 tons per year of SO_2 in 2006, by far the most for any given area of Illinois. For the sake of the health of local residents, deny MGP's request for a coal-fired boiler. The atmosphere in the Pekin area is already saturated with SO_2.

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not feasible. If compliance with such lower limits is not feasible, the permit provides that the final NOx BACT limits shall be adjusted accordingly. PSD Permit AZP-04-01, Conditions IX.E.3, 4 and 5.

On August 30, 2007, USEPA issued a PSD permit to the Deseret Power Electric Cooperative for a proposed waste-coal-fired utility boiler with a maximum capacity of 1,445 mmBtu/hr, a unit almost 3 times larger than the proposed MGP boiler. For the first 12 months of operation of the unit, the permit sets NO_x BACT as 0.088 lb/mmBtu, 30-day average. The NO_x BACT limit then lowers to 0.080 lb/mmBtu, 30-day average. PSD Permit OU 0002-04.00AP4911-1502, Condition III.D.1(c).

The Nevada Division of Environmental Protection has prepared a draft PSD permit for the proposed White Pine Energy Center, a coal-fired utility boiler with a nominal capacity of 5,216 mmBtu/hr, a unit about 10 times larger than the proposed MGP boiler. The permit would set NO_x BACT at 0.070 lb/mmBtu, 24-hour rolling average, for periods other than startup and shutdown. During these periods, NO_x BACT is set as 0.45 lb/mmBtu, 24-hour rolling average. Draft PSD permit AP4911-1502, Conditions V.2.a(11) and V. A.2.b(2).

[106] In 2006, the maximum 24-hour average SO_2 concentration monitored in Pekin was 0.093 ppm, which was three times higher than Peoria, at only 0.029 ppm, and even higher than levels monitored at most of the other monitoring stations in Illinois. The maximum 3-hour SO_2 concentration in Pekin was 0.241 ppm, compared to 0.068 ppm in Peoria, again significantly higher than levels monitored at most other stations in Illinois.

The SO_2 air quality in the Pekin area, while higher than in other areas of Illinois, should not be considered saturated so as to make it inadvisable to issue a permit for the proposed project. The modeling specifically conducted for the proposed project shows that the project would have at most an insignificant impact on SO_2 air quality. As indirectly noted by this comment, the proposed boiler would increase the amount of SO_2 in the area by less than ½ percent.

In addition, the Illinois EPA is working to reduce SO_2 emissions from existing coal-fired power plants in Illinois. The reductions in SO_2 emissions that will be achieved at power plants in the Pekin/Peoria area will be far greater than the SO_2 emissions from the proposed boiler, so that there will be a substantial reduction in the loading of SO_2 to the atmosphere in the area. The Illinois EPA has also been working with Aventine, whose coal-fired boilers are not currently equipped with scrubbers, to identify measures that can reasonably be implemented to reduce its emissions of SO_2.

48. Does the Illinois EPA have an ambient air monitoring station in Pekin? What is it showing?

The Illinois EPA operates an ambient SO_2 monitor at Fire Station 3 in Pekin, 272 Derby Street.[107] The monitor shows that air quality in Pekin complied with the SO_2 air quality standards in 2006 and 2008.[108] Three excursions of the 24-hour SO_2 air quality standard were monitored in 2007.[109, 110] Emissions of SO_2 from Aventine have been identified as likely being culpable for these exceedances. The Illinois EPA has been working with Aventine to ensure that it implements measures that in the future keep its SO_2 emissions within levels that protect the 24-hour SO_2 air quality standard.

49. The maximum predicted SO_2 impact from the proposed project is 4.93 µg/m^3, 24-hour average. That is not enough of a safety margin compared to 5.0 µg/m^3, the relevant significant impact level for 24-hour impacts.

This comment reflects a misunderstanding of the nature and role of the significant air quality impact levels used in the PSD rules. These levels define concentration below which the impacts of a project can be considered negligible or trivial. They are not

[107] The Illinois EPA also operates monitoring stations for SO_2 and ozone, PM_{10}, $PM_{2.5}$ and CO in nearby Peoria. These monitors, which provide data for pollutants other than SO_2 that can be considered representative of the Pekin area, show attainment of the applicable national ambient air quality standards. In particular, for $PM_{2.5}$ the annual average concentration was 11.1µg/m^3 in 2008. The 98th percentile value for $PM_{2.5}$, 24-hour average, was 27.0 1µg/m^3 in 2008.

[108] **In 2008, the maximum monitored short-term SO_2 concentrations were 0.241 ppm, 3-hour average, compared to the standard of 0.5 ppm, and 0.093 ppm, 24-hour average, compared to 0.14 ppm. The monitored annual average SO_2 concentration was 0.004 ppm, compared to the annual standard of 0.03 ppm.**

[109] **In 2007, the maximum monitored 3-hour average SO_2 concentration was 0.297 ppm, compared to the standard of 0.5 ppm. The monitored annual average SO_2 concentration was 0.004 ppm, compared to the annual standard of 0.03 ppm. However, there were three measurements above the 24-hour standard of 0.14 ppm, one at 0.182 ppm and two overlapping measurements at 0.162 ppm.**

[110] **These three excursions do not constitute a violation of the NAAQS because they all took place over two days. In addition, at most, the second and third excursions would ever constitute a violation as the numerical standard of the 24-hour SO_2 NAAQS is not to be exceeded more than once per year. However, these measurements are clearly of concern given the concentrations of SO_2 that were measured.**

concentrations at which the impact of a project is important or ominous. In particular, the 24-hour significant impact level under the PSD rules, 5.0 µg/m^3, is equivalent to about 0.002 ppm SO_2. This is about 1/70 of the 24-hour air quality standard for SO_2, 0.14 ppm. As such, the air quality analysis for the proposed facility, which indicates maximum modeled SO_2 impact of 4.93 µg/m^3 (0.0019 ppm), 24-hour average, shows that this project would have an insignificant or negligible effect on daily SO_2 air quality.

50. More ambient air quality monitors are needed in the area.

Given the high levels of SO_2 that have been monitored recently in the Pekin area, the Illinois EPA is working to set up a second SO_2 ambient monitoring station. This station would be located further north of MGP and Aventine, closer to downtown Pekin, rather than to the east.

51. Unlike other pollutants, for which short-term limits would be set corresponding to the averaging times of applicable NAAQS, there are no short-term limits for the SO_2 emissions of the proposed coal-fired boiler. (See Draft Permit Condition 2.1.2(b).) Instead, SO_2 emissions are only limited on a 30-day average in a pounds per million Btu heat, which does not limit hourly emissions without a corresponding hourly heat input limit. This is insufficient to ensure compliance with the short term NAAQS. When no hourly permit emission limits are required (or short-term emission limits that correspond to the air quality standard or increment periods, i.e., a 3-hour limit for 3-hour SO_2 NAAQS), the emissions from an emission unit are only limited by the physical limits of the unit (i.e., maximum theoretical emissions). This represents the worst-case scenario for emissions, which must be used to model air impacts.[111]

Limits on the short-term emissions of the proposed solid fuel-fired boiler are set in Condition 2.1.6 of the permit. SO_2 emissions of the boiler are limited to 73.9 pounds per hour, 24-hour daily average, and 123.0 pounds per hour, 3-hour average. The draft permit would have limited SO_2 emissions to 123.0 pounds per hour, 24-hour daily average. In response, to this comment, the air quality analysis for the proposed facility, which is the basis for these SO_2 limits, was reexamined. This revealed that the emission rate of 123.0 pounds per hour was used to address 3-hour SO_2 air quality impacts, not the 24-hour impacts. An emission rate of 73.9 pounds per hour was used to address 24-hour SO_2 impacts. Accordingly, in the issued permit, the 24-hour daily average emission limit for SO_2 is set at 73.9, rather than 123.0 pounds per hour, and a 3-hour average SO_2 emission limit is set at 123.0 pounds per hour. Thus, the short-term SO_2 emission limits set by the issued permit are consistent with the emission rates that were used in modeling of short-term SO_2 air quality impacts.

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[111] The USEPA's NSR Manual provides that "For both NAAQS and PSD increment compliance demonstrations, the **emissions rate** for the proposed new source or modification must reflect the <u>maximum allowable</u> operating conditions as expressed by the federally enforceable **emissions limit, operating level, and operating factor** for each applicable pollutant and averaging time." NSR Manual, page C.45, (emphasis original).

52. The draft permit would not set case-by-case MACT limits for the proposed project for emissions of hazardous air pollutants (HAPs). The existing MGP plant is already a major source for HAPs. The proposed project would be a "modification" of this source for purposes of Section 112(g)(2)(A) of the Clean Air Act. This is because the project would constitute a modification for purposes of Section 112 of the Clean Air.[112] Accordingly, the proposed project must be subject to a case-by-case determination of MACT under Section 112(g)(2)(A) of the Clean Air Act before construction can start.

The proposed project is not considered a modification for purposes of Section 112(g)(2)(A) of the Clean Act. This is because it will not be accompanied by more than a de minimis increase in emissions of HAPs from the source, which is necessary for a project to be considered a modification for emissions of HAPs as defined by Section 112(a)(5) of the Clean Air Act. In this regard, USEPA has adopted regulations, 40 CFR 63, Subpart B, for the implementation of Section 112(g) of the Clean Air Act. These regulations contain the relevant criteria that must be used to determine whether a proposed project would have more than de minimis emissions of HAPs and be considered a modification.[113] The potential emissions of HAPs from the proposed project do not meet these criteria, so a case-by-case determination of MACT is not required for the project.

53. The Project Summary states that:

> While other solid fuels could be used to "supplement" or take the place of some of the Illinois coal, MGP would not be required by the permit to use specific quantities of such supplemental fuels in the boiler. The use of such supplemental fuels would be at the discretion of MGP, subject to the general obligation that the boiler continue to comply with applicable requirements and limits when using such supplemental fuels and that any requirements associated with use of particular supplemental fuels were satisfied.
>
> Project Summary, page 3, Footnote 1

This is unlawful to the extent that it would purport to allow MGP to burn fuels that were not reviewed by Illinois EPA. First, it conflicts with 40 CFR 52.21(r), which requires construction and operation according to the application or, if inconsistent, with the terms of the permit. Second, it allows off-permit changes to project scope and properties that were not subject to public notice and comment. Moreover, Illinois EPA appears to be conceding that other fuels are available and cost effective. If such available supplemental fuels produce less air pollution, they must be reviewed in a top-down BACT analysis and BACT limits must be based on these cleaner fuels, unless MGP can demonstrate that there are

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[112] Section 112(a)(5) of the Clean Air Act provides that "The term 'modification' means any physical change in, or change in the method of operation of, a major source which increases the actual emission of any hazardous air pollutant emitted by such source by more than a de minimus amount or which results in the emission of any hazardous air pollutant not previously emitted by more than a de minimus amount." In other words, the project will both increase HAP emissions and will result in emissions of HAPs that were not previously emitted.

[113] For an existing source, USEPA has defined a modification as the fabrication, erection or installation "… of a new process or production unit which in and of itself emits or has the potential to emit 10 tons per year of any HAP or 25 tons per year of any combination of HAP." 40 CFR 63.41.

environmental, energy, economic or cost impacts that justify rejection in favor of the Illinois coal. In other words, Illinois EPA and MGP cannot have it both ways by setting BACT limits based on Illinois coal and refusing to consider other fuels, but then allow MGP at its sole discretion to burn anything else.

The statement cited in this comment is not intended to allow MGP to burn fuels that were not reviewed by the Illinois EPA, in the manner suggested by this comment. Rather, this introductory statement in the discussion of BACT in the Project Summary, which is contained in a footnote, merely addresses the capability of the proposed solid fuel-fired boiler to burn other fuels, i.e., coal tailings and biomass materials, as described earlier in the Project Summary.[114]

In addition, for these supplemental fuels, the cited statement is not "conceding that other fuels are available and cost effective," as suggested by this comment. Indeed, the statement merely indicates that the draft permit would allow coal to be used as the principal fuel of the proposed solid fuel-fired boiler. The statement is silent on the availability or "achievability" of using other alternative fuels in the boiler. That topic is specifically addressed in the body of the Project Summary. In particular, for this boiler, a possible requirement for use of biomass fuels, which would contain less sulfur than coal, is rejected because of the uncertainty about the adequacy and reliability of supply and the cost of such fuels, which at this time cannot currently be considered commercially available in Illinois in the amounts that would be needed by the proposed facility.[115] This comment is not responsive to these substantive discussions on the potential use of supplemental fuels.

54. An application for a PSD permit must include, among other information, "a description of the nature, location and typical operating schedule of the source or modification." 40 CFR 52.21(n)(1)(i).

The application for the proposed project meets this requirement. The application describes the nature and location of the proposed boiler facility, as well as MGP's existing plant. The application also provides the expected operating schedule of the proposed facility, which would be the same as the operating schedule of MGP's existing plant, i.e., essentially continuous with at most a few days of total shutdown each year, during which certain maintenance activities would be performed.

55. Among other things, an application for a PSD permit must include an analysis of the impacts of the proposed facility on soils and vegetation, as well as commercial and industrial growth associated with the facility. 40 CFR 52.21(o). There is little information provided for this project, especially as to the impacts of the fuel acquisition, including

[114] "The proposed boiler would be designed to fire pulverized coal and coal tailings with natural gas used as an auxiliary fuel for startup and flame stabilization. Biomass materials (e.g., bran and feed), which are produced at the plant, could also be used as alternative fuels in place of some of the coal fuel." Project Summary, page 1.

[115] In the draft NSR Manual, USEPA confirms that reliability in the supply of a possible fuel is a relevant consideration in the determination of BACT. When discussing consideration of energy impacts in a BACT determination, the USEPA states that "The energy impact analysis may also address concerns over the use of locally scarce fuels. The designation of a scarce fuel may vary from region to region, but generally a scarce fuel is one which is in short supply locally and can be better used for alternative purposes, or one which may not be reasonably available to the source either at the present time or in the near future." NSR Manual, page B.31.

impacts on endangered species of vegetation.

The application submitted by MGP addresses impacts of the proposed facility on soils and vegetation, as well as growth impacts associated with the facility.[116] This material in the application is adequate given the nature and scale of the proposed facility. In particular, the proposed facility would not have significant impacts on air quality. It would be developed to support an existing manufacturing plant located in an existing industrial area.

The proposed facility would also be developed to use commercially available fuels. That is, MGP is not proposing to develop a new coal mine to specifically provide the coal for the proposed facility. In such circumstances, it is not appropriate for MGP to speculate on the occurrence of any impacts on endangered species of vegetation that may be located in the vicinity of existing coal mines in Illinois due to the emissions and air quality impacts of those existing mines. Such impacts, if indeed there are such impacts, should not be considered to be a result of the proposed project but be a result of the existing mining operations.

56. MGP plans to use Illinois coal as a fuel for the proposed facility but there is no information in the application or materials provided by the Illinois EPA disclosing the environmental impacts, including soil and vegetation impacts, associated with mining and transportation of the coal. The impacts from long-wall mining (increasingly pursued in Illinois) include the destruction of high-quality farmland, drying up of streams and springs, and the loss of life-sustaining soil. The analysis of these impacts must be done and provided to the public prior to the close of the public comment period.

There are a number of existing coal mines located within 50 or 100 miles of the MGP plant, as identified in the application, that could potentially supply coal to the proposed facility. These mines are subject to separate regulatory and permitting programs that have been specifically developed to prevent and mitigate detrimental impacts from mining activity. This includes planning for ground subsidence, as is a particular concern for long wall mining, to prevent damage to structures, agricultural productivity and the natural environment, as well as provision for land reclamation following completion of mining. As these existing mines are separate sources from the MGP plant for purposes of PSD, it is beyond the scope of the application for the proposed facility to further address the impacts of these existing mines.

Given the relatively small amount of coal that would be used by the proposed facility (at most about 200,000 tons of Illinois coal annually), it is unlikely that a new mine would ever be opened to specifically supply the proposed facility. However, development of any new coal mine in Illinois would be subject to permitting by the Illinois Department of Natural Resources. As part of that permitting process, the public would be able to submit comments on the proposed mine project, including comments about the potential impacts from long wall mining if this method of mining were proposed.

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[116] **Refer to Sections 6.14.1 and 6.14.3, in MGP's supplement to the application received on August 6, 2007.**

57. The issuance of a PSD permit for this project would be a federal action subject to consultation requirements under Section 7 of the federal Endangered Species Act. While MGP requested that USEPA Region 5 conduct such consultation with the United States Fish and Wildlife Service for this project,[117] I have not seen any documentation that this consultation has occurred.

Consultation under the federal Endangered Species Act has been concluded by USEPA. In a letter date stamped February 26, 2009, the United States Fish and Wildlife Service (USFWS)[118] concurred with the USEPA that issuance of the PSD approval for the project will not likely affect federally listed endangered species. Federal PSD permitting actions, including PSD approvals issued by states under delegation agreements, are subject to consultation under the federal Endangered Species Act. The responsibility for performing this consultation rests with USEPA and is separate from PSD permitting as administered by the Illinois EPA. Any comments on the appropriate scope of consultation or the findings of the consultation process should be directed to the USEPA or, alternatively, the USFWS.

58. Consultation under the federal Endangered Species Act must consider endangered species that may be impacted by the proposed source of fuel for the coal-fired boiler, as well as endangered species affected by the proposed project itself.

The responsibility for consultation under the federal Endangered Species Act lies with USEPA. Comments about the appropriate scope of consultation or the findings of the consultation process should be directed to the USEPA or, alternatively, the USFWS.

59. The results of this consultation must be made available to the public prior to the close of the comment period, particularly if the consultation involves consideration of endangered plant species.

Applicable federal procedures for consultation under the federal Endangered Species Act do not provide for the opportunity for public comment on the consultation process.

60. Condition 1.8(b)(i) of the draft permit states that the permit "shall become invalid if construction of the affected boiler is not commenced within 18 months" after the effective date of the permit. This condition must clarify that a new BACT determination and modeling analysis must be obtained for any <u>emission unit</u> that does not commence construction within 18 months. Because this project will be a staged 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 construction of 18 months. Additionally, as written, the

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[117] Letter, dated March 12, 2007, from Mostardi and Platt, MGP's consultants, to USEPA, Region 5.

[118] Letter, dated stamped February 26, 2009, Richard C. Nelson, US Department of the Interior, Fish and Wildlife Service, Rock Island Field Office, to Pamela Blakley, USEPA, Region 7, Air Permits Section.

condition could be misinterpreted to mean that the same BACT determination and air quality analysis could be reused in a new permit application. If 18 months pass, a new BACT determination must be made and a new air quality analysis performed.

This condition of the draft permit generally reflects the relevant language of the PSD rules, 40 CFR 52.21(r)(2),[119] 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.

As further noted by this comment, Condition 1.8(b)(i) of the draft permit would not specify whether a request to extend the permit would need to be accompanied by a new air quality analysis or a new BACT determination. In this regard, 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.

61. Condition 1.8(b)(i) of the draft permit refers only to "construction of the affected boiler" when it should refer to construction of any emission unit.

This comment has identified a minor discrepancy between the language in 40 CFR 52.21(r)(2) and the text of draft Condition 1.8(b)(i), which has been corrected in the issued permit. As the draft permit condition referred to construction of a specific unit, i.e., the new boiler, it is not consistent with the language of 40 CFR 52.21(r)(2). 40 CFR 52.21(r)(2) does not refer to the construction of individual emission units, but to construction of the project (or the phases of a project, for a phased construction project). Accordingly, Condition 1.8(b)(i) in the issued permit does not refer to construction of either the "affected boiler" or "any emission unit," instead implicitly

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[119] "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." 40 CFR 52.21(r)(2).

referring to commencement of construction of the proposed project.

62. A permit should not be issued unless significant additional analyses are performed, a revised draft permit is prepared, and the public has another opportunity to review and comment on the new draft permit.

The comments submitted on the proposed project do not raise matters for which a further opportunity for public comment is warranted. The public has been provided with an opportunity to review and comment on the proposed project and draft permit. The logical outcome of this process is that the Illinois EPA thoughtfully consider any comments that are submitted and, as appropriate, take necessary actions to respond to those comments. A decision by the Illinois EPA to conduct with additional research or analysis to respond to public comments does not trigger the need for a further opportunity for public comment.

63. Does the Illinois EPA monitor the air quality of the community or is the air only tested at the site of each individual company?

The Illinois EPA conducts ambient air quality monitoring to measure the general air quality in an area, addressing the combined impacts of all sources on actual air quality in the area.

Individual companies or sources conduct emissions testing, operational and emissions monitoring, and recordkeeping to confirm compliance of their operations with applicable emission standards and limitations that govern the operations, as well as to generally determine the amount of their emissions. For example, for the proposed solid fuel-fired boiler, continuous emissions monitoring will have to be conducted for SO_2, NO_x and CO. An opacity monitor and bag leak detection system would need to be operated to confirm proper operation of the fabric filter to control particulate.

64. The particulate matter emissions of the proposed coal-fired boiler would be very costly healthwise to children, contributing to health problems with asthma, as well as the cost to their families for medical care.

The air quality analysis for particulate matter impacts, like the analysis for SO_2, shows that the proposed project will have an insignificant effect on ambient air quality.[120] At the same time, the presence in the area of children and adults with

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[120] **USEPA has not yet adopted significant impact levels for $PM_{2.5}$. Accordingly, it is appropriate to refer to the USEPA's proposed rulemaking for significant impact levels for $PM_{2.5}$. (Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers (PM2.5) – Increments, Significant Impact Levels (SILS) And Significant Monitoring Concentrations (SMC), 72 FR 54112, September 21, 2007). This rulemaking puts forth for comment three possible options for the annual and 24-hour significant impact levels for $PM_{2.5}$, i.e., 1.0 and 5.0 µg/m^3, 0.8 and 4.0 µg/m^3, and 0.3 and 1.2 µg/m^3, respectively.**

The proposed project's modeled impacts would not be considered significant for $PM_{2.5}$ under Option 1, i.e., the modeled concentrations of PM_{10} are less than the significant impact levels for $PM_{2.5}$ proposed in this option. Under Option 2, the $PM_{2.5}$ impacts would only have to be about 80 percent of the modeled impacts for PM_{10} to not be significant. Under Option 3, to not be significant, the $PM_{2.5}$ impacts would have to be about 30 percent of the modeled impacts for PM_{10}. These levels of adjustment to the modeled concentrations for PM_{10} to convert

respiratory diseases, including asthma, and other diseases affected by air quality is an important issue. Improvements in air quality require that existing sources be better controlled or replaced with new, lower emitting sources. In addition, regulatory programs and initiatives are ongoing to further reduce the emissions from existing sources. These reductions in emissions will be accompanied by improvements in air quality for particulate matter, as well as SO_2.

At the same time, efforts also continue to be made to improve public awareness of daily air quality levels. This is particularly important for individuals with asthma or other chronic respiratory diseases because, in addition to other medical care and treatment, it allows such people to take appropriate measures to reduce any added risk to their health posed by poor air quality, by reducing time spent outdoors, avoiding physical exertion, and taking any extra medications that are prescribed during such conditions. To assist asthmatic individuals and others who are particularly sensitive to ambient air quality, the Illinois EPA uses the Air Quality Index to report air pollution levels on a daily basis. This enables people who may be affected by poor air quality to appropriately plan and adjust their activities.

65. Pekin does not allow burning of leaves, which I agree with entirely. However, is this because the air pollutant levels are already so high?

The nature of the burning of leaves is such that the accompanying emissions pose potential health impacts for individuals with respiratory conditions who live directly downwind, as well as general nuisance impacts for the surrounding area, even in areas where air quality is otherwise very good. As such, in populated areas, a prohibition of or restrictions on leaf burning constitute very reasonable public policy unrelated to the background level of air quality in the area. At the same time, background air quality in Pekin may have been a further factor in the City of Pekin's decision to prohibit leaf burning.[121]

66. What will be the combined effect of the emissions of MGP, Aventine, Midwest Generation Powerton, and Ameren-Edwards on the air quality of the Pekin area, especially for NO_x, CO, and lead?

As discussed, air quality will be effectively unchanged with this project and the Pekin area will continue to comply with the national ambient air quality standards. As new control equipment is added to the coal-fired boilers at existing facilities in the area and reductions in emissions occur at those facilities, air quality will improve.

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to concentrations of $PM_{2.5}$ are realistic. In particular, ground-level emissions due to vehicle traffic on roadways have a large contribution to the modeled PM_{10} impacts from the proposed facility and the $PM_{2.5}$ emissions of roadways will be only about 15 percent of their PM_{10} emissions.

To ensure that the permit for the proposed facility protects $PM_{2.5}$ air quality, the issued permit includes a limit on the roadway emissions of $PM_{2.5}$ from the proposed facility, which results in the $PM_{2.5}$ air quality impacts of the proposed facility meeting Option 2, the middle option for $PM_{2.5}$ Significant Impact Levels.

[121] Under state law, other than in Cook County (Chicago area), local city and village governments retain the authority to decide whether or not to allow leaf-burning.

67. I am concerned that environmental regulations allow for some emissions of particulate matter and harmful gases, such as SO_2 and CO. While allowable amounts are small, if improperly dispersed they could add significantly to already existing pollution in the area.

The computerized dispersion modeling conducted for the proposed project addresses the concern expressed by this comment. It examined the effect of the emissions of the proposed solid fuel-fired boiler and other proposed new emission units, which would indeed be well controlled, on air quality in the area. It shows that these new units will have at most only a very small effect on local air quality as actually released into the atmosphere through the associated stacks and vents.

68. The ambient monitoring station at Firehouse 3 will not point to any definite source if excessive SO_2 is measured in the ambient air.

This monitoring station is sited so that it can be used to identify whether a particular source is responsible for elevated levels of ambient SO_2. This is because the principal sources of SO_2 emissions are all in different directions from the monitoring station. Accordingly, local weather data for wind speed and direction, on an hour-by-hour basis, during periods of elevated ambient concentrations can be used to identify the source or sources that contributed to elevated ambient SO_2.

69. Abatement systems, such as scrubbers, are subject to breakdown and problems, and require maintenance and therefore are never totally effective as designed 100 percent of the time. Would MGP cease operation if the control system became less than 100 percent operative?

The circumstances described in this comment are the reason why the project includes a natural gas-fired auxiliary boiler, as well as the solid fuel-fired boiler. The auxiliary boiler enables MGP to continue operation during scheduled maintenance of the main boiler, as well as the ability to continue operation during unplanned breakdowns of the main boiler. In this regard, as related to certain applicable state emission standards, in the event of a breakdown and excess emissions from the solid fuel-fired boiler, MGP is only allowed to continue operation of that boiler as necessary to prevent risk of injury to personnel or severe damage to equipment, not for its own economic benefit. MGP must also "as soon as practicable, repair the affected boiler or remove the affected boiler from service, unless doing so would cause further excess emissions." (Refer to Condition 2.1.3(b).)

70. I am concerned about the questionable effectiveness of monitoring by MGP. This monitoring would be conducted by MGP employees with reports sent periodically to the Illinois EPA. Would a report showing less than perfect operation ever be sent?

Practices for continuous emissions and operational monitoring are well established and effective. Monitoring reports are submitted to the Illinois EPA by sources that show that there have been violations of applicable emission standards and requirements. When violations occur, such reporting is routine because violations of emission standards are generally civil matters, which are the responsibility of the source and only carry monetary penalties. However, the intentional submittal of false

information or a false report is a criminal matter, with potential liability for both the source and the responsible individuals, with risk of both monetary penalties and imprisonment upon conviction.

71. Rather than building a new coal-fired boiler, the state or the City of Pekin should help negotiate an accommodation with Ameren CILCO for MGP to continue the operation of CILCO's gas fired boiler facility, or MGP should relocate its plant to a rural, sparsely populated area or find an alternative fuel source.

This comment does not identify practical alternatives to the proposed project. Neither state nor local government can make Ameren subsidize MGP's operations. It would be wholly impractical to relocate MGP's existing plant, which is located in an industrial area in Pekin, to a new site. Nor are there "alternative fuels" that are available commercially in sufficient quantities to meet MGP's energy needs.

72. What does the phrase "no significant impact on health concerns to the community" mean? Even though the proposed facility would meet emission standards, it would still be permitted for significant amounts of emissions.

As applied to the proposed facility, this phrase means that the concentration of pollutants in the ambient air will be effectively unchanged with the addition of the proposed facility. In this regard, the emissions from the proposed solid fuel-fired boiler and other units at the proposed facility would be well-controlled and should not measurably affect the levels of pollutants in Pekin's ambient air.

73. The proposed facility is of concern as it would contribute to deposition of mercury in the Illinois River.

Existing coal-fired power plants contribute significant amounts of mercury to the environment through their emissions. However, the proposed solid fuel-fired boiler would be equipped with modern emission controls and emit a fraction of the mercury currently emitted by existing power plants. Reductions in mercury emissions and the mercury levels in fish will require application of control measures to existing power plants. In this regard, Illinois recently adopted rules for the mercury emissions of coal-fired power plants located in Illinois. USEPA must also adopt national rules for control of mercury emissions from coal-fired power plants.[122] Even then, the magnitude of the reduction in mercury levels in freshwater fish is uncertain, as transport of mercury emissions occur on a global scale.

Given these circumstances, it is important that people be aware of and understand the advisories that the State of Illinois issues for consumption of fish caught in Illinois waters. In particular, a statewide advisory has been issued for mercury contamination as a protective measure given new studies indicating that consumption of fish with high mercury levels may pose a risk for sensitive populations. These

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[122] **While USEPA had adopted such rules, they were successfully appealed as the court found that USEPA had not fulfilled relevant obligations under the Clean Air Act.**

sensitive populations are children younger than 15 years of age and women who are or may become pregnant, to protect the unborn and nursing infants. The statewide advisory recommends that such individuals eat no more than one meal per week of predator fish taken from Illinois' waters. Additional recommendations have also been made for certain lakes in Illinois and the Ohio and Rock Rivers. Further information on the fish advisories for mercury, as well as for the advisories for other contaminants, are available from the Illinois Department of Public Health: www.idph.state.il.us/envhealth/fishadv/specialmercury.htm.

74. How much CO_2 is produced with the current use of natural gas for the MGP plant as compared to the proposed coal-fired boiler (recognizing that there is some efficiency from cogeneration)?

While Ameren reported actual annual CO_2 emissions of 99,000 and 82,000 tons from its Indian Trails facility in 2007 and 2008, it did not provide the information needed for the requested comparison to be performed, e.g., the amount of electricity that was generated by this facility.

75. How does the limit in the draft permit for the mercury emissions of the proposed coal-fired boiler compare to the limits in the Illinois Mercury Rule, 35 IAC Part 225, Subpart B, for coal-fired electric generating units. For a new boiler of this size, that is so close to it being in the range that is regulated by the Illinois Mercury Rule, this should be considered.

The limit for the mercury emissions of the proposed solid fuel-fired boiler is 0.000003 lb/mmBtu. The standards in the Illinois Mercury Rule, either 0.0080 lb/GW-hr gross electrical output or 90 percent control of emissions, are significantly more stringent.[123] However, the limit in the permit is the standard that was set by USEPA in the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63 Subpart DDDDD.[124] As such, it reflects an appropriate limit for the mercury emissions of the proposed boiler, which is an industrial boiler. The proposed boiler would be much smaller than most of the utility boilers addressed by the Illinois Mercury Rule, most of which are many times larger than the proposed boiler.[125]

76. Would MGP receive any state or federal grant money for this project?

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[123] The output-based limit in the Illinois Mercury Rule, 0.008 lb/GW-hr, is nominally equivalent to about 0.0000008 lb/mmBtu. The efficiency-based limit, 90 percent reduction, which would most likely be utilized by generating units burning Powder River Basin coal, is nominally equivalent to about 0.000000125 lb/mmBtu.

[124] 40 CFR 63.7500 (69 FR 55,217, September 13, 2004). This NESHAP is no longer in effect as it was subsequently appealed and vacated by the courts. The USEPA is now engaged in further evaluation of the emissions of industrial boilers and process heaters in preparation for reproposing NESHAP rules for boilers and process heaters.

[125] Of the over 50 electrical generating units subject to the Illinois Mercury Rule, the proposed boiler, with a nominal capacity of 493 mmBtu/hr, would only be larger than two units, which each have a capacity of 415 mmBtu/hr. These two units are scheduled to be permanently shut down so would not be subject to limits under the Illinois Mercury Rule. Otherwise, most subject units are three times the size of the proposed boiler, with many subject units being ten times its size.

MGP indicates that it has not applied for grant money for this project. Given the nature of grant programs and the current state of the economy it is uncertain that any grants would be available for the project even if MGP were to apply.

77. MGP is already using cogeneration with the existing natural gas boilers so this project is not an upgrade.

This project is clearly an upgrade from the perspective of MGP and the economy of the state of Illinois, as it would improve the financial position and competitiveness of MGP's Pekin plant.

78. Since the heat content of coal tailings is less than that of coal, as coal tailings contain more rock and ash material, it seems like the coal-fired boiler would be allowed to have more emissions when coal tailings were being used as fuel. How does the Illinois EPA look at that and determine what kind of emissions might be coming from coal tailings?

The solid fuel-fired boiler would not be allowed more emissions when coal tailings are used as fuel. This is because the applicable emission standards and BACT emission limits set for this boiler are expressed in terms of the fuel heat input to the boiler, i.e., pounds of emissions per million Btu heat input. This accounts for differences in the heat content of various fuels, so that more emissions are not allowed when a fuel with a lower heat content is being fired. Effectively, emission limits are set on a standardized basis in terms of the energy value of the fuel that is being fired.

Beyond this, the emissions associated with firing of coal-tailings should generally be considered similar to those from firing of coal. This is because coal-tailings are a mixture of "regular coal," which contains some ash or rock material, and additional rock material. As such, no new materials are present in the coal-tailings and the pollutants emitted from burning of coal and coal-tailings are identical.

79. Even though the proposed facility is not subject to the federal acid rain program, what about the facility's contribution to acid rain?

While SO_2 and NO_x will be emitted from the boilers, their contribution to acid rain would be infinitesimal. The emissions of SO_2 and NO_x from the facility would potentially be only a few hundred tons per year whereas acid rain is the net result of emissions of millions of tons per year.

80. MGP should be required to use cleaner coal.

MGP has elected to use coal that is locally available in Illinois, which is a reasonable decision given that it ensures a reliable supply of coal at an affordable cost. The construction permit requires MGP to appropriately control the emissions that would result from use of this coal.

81. Use of natural gas is also preferable to use of coal because combustion of natural gas emits a fraction of the carbon monoxide (CO) emissions from the combustion of coal.

The emissions of CO from coal-fired boilers do not pose particular environmental concerns.[126] As such, differences in the levels of CO emission are not a significant factor in the choice of fuel for the proposed facility.

82. Although MGP is required to conduct emissions and operational monitoring, the Illinois EPA itself should do some of this monitoring.

"Self-monitoring" by sources of their operations is a well established practice. It provides a level of monitoring that is far more comprehensive and consistent than the occasional monitoring that the Illinois EPA could perform given the number of sources in Illinois. Self-monitoring also directly provides relevant data to sources so as to assist them in proper operating equipment and maintaining compliance. Finally, the costs for this monitoring are appropriately placed directly on the sources themselves, rather than being indirectly paid for by tax revenues.

83. For the proposed coal-fired boiler, will the scrubber control emissions of SO_2 so that MGP's SO_2 emissions with the proposed project will be no worse than at present?

MGP's emissions of SO_2 will not be lower than if natural gas continued to be used as fuel. While the use of a scrubber will reduce the SO_2 emissions of the proposed solid fuel-fired boiler to a fraction of the uncontrolled emissions of SO_2, routinely collecting over 98 percent of the sulfur in the coal, the scrubber will not maintain SO_2 emissions at the level that would accompany use of natural gas. However, as discussed, the scrubber will control SO_2 emissions so that actual concentration of SO_2 in the ambient air will increase by at most negligible amounts and be essentially unchanged.

84. Will MGP have to meet current technology requirements for control of emissions from the proposed project?

Yes. As new boilers would be constructed, the boiler will also have to meet federal new source performance standards and utilize best available control technology.

85. What is the status of MGP under its consent decree? If MGP is still in the process of fixing that problem, how would this project affect that problem?

MGP has completed the installation of required equipment to better control emission from its feed drying operations, which were the subject of enforcement actions.[127] As

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126 For the proposed boilers, the maximum modeled 1-hour average CO concentration is 27.9 µg/m^3, compared to the PSD significant impact level of 2000 µg/m^3. The maximum 8-hour average CO concentration is 15.8 µg/m^3, compared to the significant impact level of 500 µg/m^3.

127 MGP was the subject of coordinated federal and state enforcement actions, which were settled, respectively, before the U.S. District Court for the Central District of Illinois in December 2005 and the Illinois Pollution Control Board in November 2006. Both settlements require MGP to install equipment to control the emissions of its feed drying operation, followed by emission testing for the new equipment. MGP has installed the required equipment and emission testing has confirmed compliance with applicable limits.

such, there is not an outstanding problem that might be affected by this project.

GENERAL COMMENTS

a. MGP should be applauded for its efforts to solidify its future by becoming self-sufficient for its steam and electricity needs. This project would also result in more jobs and a stronger local economy.

b. The Pekin Area Chamber of Commerce supports this project. The proposed project would use state-of-the-art emissions control technology. The project will ensure the sustainability of the MGP's Pekin plant, providing increased job security for the 140 employees at the plant. Lastly, the proposed facility will utilize Illinois coal as its primary fuel.

c. I am confident that the Illinois EPA will do its duty to control the emissions.

d. I am especially concerned about the increased emissions of particulate and mercury. The guarantees that these will be well taken care of are not as solid as I would like.

e. I encourage the Illinois EPA to look at the overall impacts to the air in this community, not only here in Pekin, but upriver for the hundreds of thousands of people that may be impacted by this facility.

f. Pekin deserves better.

g. The south end of Pekin is so much cleaner than it was when I was young.

FOR ADDITIONAL INFORMATION

Questions about the public comment period and permit decision should be directed to:

Bradley Frost, Community Relations Coordinator
Illinois Environmental Protection Agency
Office of Community Relations
1021 North Grand Avenue, East
P.O. Box 19506
Springfield, Illinois 62794-9506

217-782-7027 Desk line
217-782-9143 TDD
217-524-5023 Facsimile

brad.frost@illinois.gov

LISTING OF SIGNIFICANT CHANGES
<u>BETWEEN THE DRAFT PERMIT AND THE ISSUED PERMIT</u>

1. Finding 1(a) and Condition 2.1.1: This finding and condition described the general nature of the project and boiler. A statement was added noting that the solid-fuel fired boiler would be used for cogeneration to produce process steam and electricity for use at the existing plant. *This change was made because cogeneration is a important aspect of the project.*

2. Finding 1(b): This finding, which identifies the fuels for the solid fuel-fired boiler, no longer includes specifications for the design fuel for the boiler. *This change was made because, while the boiler is generally designed for Illinois Basin coal, the specifications for the coal supply would change depending upon the specific source of coal for the boiler.*

3a. Condition 1.1 and Table I: In this condition and associated table, which address overall emissions of the proposed facility, the limits for emissions of hydrogen chloride and mercury were replaced with a limit on emissions of individual hazardous air pollutants (HAP). A limit on emissions of total HAP was added. *As emissions of hydrogen chloride and mercury from the solid fuel-fired boiler are specifically limited in Condition 2.1.6, it is preferable that the provisions in Table I generally limit HAP emissions, both individual and total, from the proposed facility so that the facility is not a major source for HAP emissions.*

b. Condition 1.1 and Table II: This condition and associated table, which would have limited the hourly and annual emissions from the solid fuel-fired boiler, were not carried over to the issued permit. *These provisions are not necessary because they are redundant with the limits set in Condition 2.1.6(a). In addition, Table II erroneously listed annual average emission rates for CO, NO_x, SO_2 and VOM rather than actual short-term emission limits.*

4. Condition 1.8(b)(i): This condition, which addresses the period within which construction of the proposed facility must commence under the permit, has been revised to more closely track the relevant language of 40 CFR 52.21(r)(2). *This change, which was made in response to public comments, was made to maintain consistency with the relevant regulatory language.*

5a. Condition 2.1.2(b)(i): This condition, which sets the numerical BACT limits for CO, PM, and NO_x emissions of the solid fuel-fired boiler, has been converted from a table into several narrative conditions. *This change was made to accommodate other changes that were made to BACT limits in response to public comments, as discussed below.*

b. Conditions 2.1.2(b)(ii)(A) and (B) (Draft Condition 2.1.2(b)(i)): The draft permit would have set limits for particulate in terms of PM_{10}. The issued permit limits particulate in terms of particulate matter, which is more stringent, while also noting that the limits also serve to restrict emissions of PM_{10} and $PM_{2.5}$. *These changes, which were made in response to comments, set more stringent BACT limits than would have been set by the draft permit.*

c. Condition 2.1.2(b)(ii)(C): This new condition provides for the establishment of a numerical BACT limit for particulate in terms of $PM_{2.5}$ based upon testing of the $PM_{2.5}$ emissions of the boiler and an evaluation of the $PM_{2.5}$ emission rate that is achievable, as further addressed in new Conditions 2.1.7-2(a)(ii) and 2.1.11. *This change and other related changes to the issued permit were made in response to a recent action by USEPA on the PSD rules in which it stayed the "grandfather provision" for $PM_{2.5}$ emissions for a period of three months. They also respond to public comments that argue that the permit must address $PM_{2.5}$ as a pollutant that is currently regulated under the PSD rules. Since authoritative test data for $PM_{2.5}$ emissions and other information needed to set a BACT limit for the emissions of $PM_{2.5}$ from the proposed solid fuel-fired boiler is not available at this time, this condition and associated conditions set forth a process whereby a numerical BACT limit for particulate in terms of $PM_{2.5}$ will be set when such information is or should be available.*

d. Condition 2.1.2(b)(iii) (Draft Condition 2.1.2(b)(i)): The draft permit set NO_x BACT at 0.10 lb/mmBtu. This condition was enhanced with a second BACT limit, 0.08 lb/mmBtu, 30-day rolling average, for loads of 60 percent or greater. *This change was made as a result of the Illinois EPA's further review of NO_x BACT. This review concluded that a more stringent BACT limit can be set for the normal operation of the solid fuel-fired boiler, i.e., operation at a load of 60 percent or greater.*

e. Condition 2.1.2(b)(iv) (Draft Condition 2.1.2(b)(iii)): This condition, which sets the SO_2 BACT limits for the solid fuel-fired boiler, was revised to clarify when limits become applicable. This condition now clearly provides that the 0.185 lb/mmBtu limit applies upon initial startup of the boiler. Only the control efficiency requirement, i.e., minimum 98 percent control if the SO_2 emission rate is 0.140 lb/mmBtu or greater, applies 18 months after startup. The condition also clarifies that both these SO_2 limits apply on a 30-day average, consistent with the format of NSPS limits for SO_2 and the format commonly used for SO_2 BACT limits for solid fuel-fired boilers. *These changes were made to clarify the effectiveness and averaging times of the SO_2 BACT limits.*

6. Condition 2.1.6(a): Various changes were made to this condition, which sets the permitted emissions of the solid fuel-fired boiler:

   a. Limits are now also set for emissions of fluorides, lead and hydrogen chloride. *Fluorides and lead are relevant PSD pollutants for the boiler and hydrogen chloride is a relevant HAP, which are potentially emitted in amounts that warrant being explicitly addressed in the permit.*

   b. The hourly limit for emissions of mercury was removed. The annual limit was corrected to 0.0065 tons/year, from 0.0060 tons/year. The annual limit on mercury emissions was also moved to the narrative condition that limits the mercury emission rate. *The hourly limit on mercury emissions was not practically enforceable, as it is inconsistent with the compliance methodology that was adopted by USEPA under the Clean Air Mercury Rule (CAMR), which is being relied upon in this permit. The annual limit in the draft permit reflected a rounding error compared to emission data in the application. The other changes were made for clarity, i.e., it was appropriate to establish mercury emissions in one condition rather than in two separate conditions.*

c. The annual limit for NO_x emissions has been reduced to 183.4 tons per year, from 215.7 tons per year in the draft permit. *This change was made to account for a reduction in annual NO_x emissions due to the additional NO_x BACT limit, which was established is response to public comment. With the limit of 0.08 lb/mmBtu for operation of the boiler at 60 percent load or more, potential annual emissions of the boiler would be reduced by 15 percent.*[128]

d. The short-term SO_2 limit has been reduced to 73.9 pounds per hour (24-hour daily average), from 123 pounds per hour in the draft permit. In addition, a short-term SO_2 limit is set on a 3-hour average basis at 123 pounds per hour. These are the SO_2 emission rates used in the short-term air quality modeling. *These changes were made to respond to public comments that argued that SO_2 emissions limits must be set that correspond to the averaging times of the national ambient air quality standards. These limits will help to protect SO_2 air quality in an area that has experienced high levels of SO_2 ambient air quality.*

7. Condition 2.1.6(c): This new condition provides for the establishment of numerical limits on the permitted emissions of the solid fuel-fired boiler for particulate in terms of $PM_{2.5}$ when the numerical BACT limit for $PM_{2.5}$ is set. *This change was made in response to the recent action by USEPA on the PSD "grandfather provision" for $PM_{2.5}$ emissions. It also responds to public comments related to the proper status of $PM_{2.5}$ under the PSD rules. Since these limits for permitted emissions are derived from the numerical BACT limit and the information needed to set that limit is not available at this time, this condition set forth a process whereby limits for permitted emissions will be set when the numerical BACT limit for particulate in terms of $PM_{2.5}$ is set.*

8. Condition 2.1.7-2(a)(ii): This new condition requires the Permittee to conduct a series of at least three tests for the $PM_{2.5}$ emissions of the solid fuel-fired boiler. *This testing is required to collect authoritative data upon which to base the numerical BACT limit that must be established for $PM_{2.5}$ emissions. To ensure that the testing addresses the potential change in the performance of the control system over time, the individual tests are to be performed at approximately one year intervals, with the series of tests to be completed no later than 36 months after initial startup of the boiler.*

9. Condition 2.1.7-2(b)(ii): This new condition addresses the test method that is to be used for measurement of $PM_{2.5}$ emissions, specifying that an applicable Recommended Test Method

[128] Because of the additional NOx BACT limit for the solid fuel-fired boiler, the permitted annual NO_x emissions of the boiler in the issued permit are 15 percent lower than in the draft permit, 184.3 tons per year rather than 215.7 tons per year. This is based on this boiler operating at less than 60 percent load for at most 25 percent of the time each year or for at most 2190 hours per year.

Average NOx Limit = [2190 x 0.10 + (8760 – 2190) x 0.08]/8760 = 0.085 lb/mmBtu

This average NOx limit results in a 15 percent reduction in permitted annual NOx emissions compared to the limit in the draft permit.

(0.10 – 0.085)/0.10 = 0.15, or 15 percent adopted by USEPA by rule shall be used. The condition also provides for use of certain other test methods in the event that USEPA has not adopted a Recommended Test Method by the time that testing for $PM_{2.5}$ must be conducted. *This condition is included to require use of a test method that should provide authoritative measurements of $PM_{2.5}$ emissions. Such method would ideally be a Recommended Test Method but a "USEPA endorsed" method may need to be used if USEPA has not completed the adoption of a Recommended Test Method when testing of $PM_{2.5}$ emissions must be conducted.*

10. Condition 2.1.7-2(c): This condition, which addresses the content of reports for emission testing, has been developed to require that these reports include information confirming proper design and operation of the control system on the solid fuel-fired boiler for control of $PM_{2.5}$. *This change was made so that the test reports would include relevant background information related to the control of emissions of $PM_{2.5}$, as well as the measured emission data for $PM_{2.5}$.*

11. Condition 2.1.11: This new condition addresses the process by which the BACT limit for the emissions of filterable $PM_{2.5}$ from the solid-fuel fired boiler, as addressed earlier in new Condition 2.1.2(b)(ii)(C), will be established. The condition provides that this limit shall be set based on the results of the required testing for $PM_{2.5}$ emissions testing of the boiler, an evaluation conducted by the Permittee, and other relevant information. The limit will be set at 0.008 lb/mmBtu, a rate that should be achievable,[129] unless the Permittee demonstrates and the Illinois EPA determines based on this information that this rate is not achievable by the control system installed on the boiler. If it is determined that a limit of 0.008 is not achievable, following opportunity for public comment, the permit will be revised to set a limit that is achievable, which limit may in no case be greater than 0.012 lb/mmbtu. If the Permittee does not perform the specified emission testing or perform an evaluation in a timely manner, the BACT limit immediately becomes 0.008 lb/million Btu. *This condition was added to the permit to provide a structured process for the establishment of a numerical BACT limit for the $PM_{2.5}$ emissions of the boiler when the results of authoritative emission testing are available upon which to set such a limit. A target value for this limit, as well as a ceiling value for the limit, are included to define the permissible range of limits from this process and to facilitate and expedite the process by which the limit for $PM_{2.5}$ emissions will be set.*

12. Condition 2.2.6: This condition, which sets the permitted emissions from material handling operations, other than handling of fly ash, was expanded to include limits for hourly PM emissions and annual PM and PM_{10} emissions. *The modeling of the air quality impacts from*

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[129] The permit sets a BACT limit of 0.012 lb/mmBtu for filterable particulate matter emissions, as would be measured by USEPA Reference Method 5. For purposes of the target value for emissions of $PM_{2.5}$, it is presumed that one half of these particulate emissions would be attributable to the filter fabric or filter media and the rest of the emissions would be attributable to other factors that affect the performance of the baghouse, notably leakage around the filter housing. The use of an enhanced filter media can reasonably be relied upon only to reduce the contribution to emissions related to the filter media itself. It is further assumed that the contribution of the filter media to emissions would be reduced by at least 75 percent with the enhanced media, resulting in a target emission limit of 0.008 lb/mmBtu.

0.006 + 0.75 x 0.006 = 0.0075 lb/mmBtu, ≈ 0.008 lb/mmBtu, with appropriate rounding *the project were based on these hourly emission rates for the material handling operations so it is appropriate that the permit limit emissions to these rates.*

13. Condition 2.3.6: This condition, which sets the permitted emissions of fly ash handling, now includes limits on PM_{10} emissions, a regulated pollutant under PSD. *The modeling of the air quality impacts from the project were based on these emission rates for fly ash handling operations so it is appropriate that the permit limit emissions to these rates.*

14. Condition 2.4.6: This condition, which sets the permitted emissions of road dust from vehicle traffic at the plant associated with this project, now include limits on emissions in terms of PM_{10} and $PM_{2.5}$. *The modeling of the air quality impacts for PM_{10} from the project reflected this PM_{10} emission rate for roadways so it is appropriate that the permit limit emissions to this rate. Similarly, the Illinois EPA's assessment of the $PM_{2.5}$ air quality impacts of the proposed facility relied on this emission rate for $PM_{2.5}$ to conclude that the $PM_{2.5}$ impacts from the proposed facility would not be significant, so it is appropriate that the permit limit $PM_{2.5}$ emissions to this rate.*

15. Condition 2.5.2(a): This condition, which identifies the BACT technology for the proposed auxiliary boiler, now also lists flue gas recirculation, which had not been mentioned in the draft permit as a control technology for the natural gas-fired boiler. *To correct this oversight, flue gas recirculation has now been included in this condition.*

16. Condition 2.5.3-1(b)(ii): This condition of the draft permit, which addressed the NSPS standard for SO_2 emissions for the proposed auxiliary boiler, has not been carried over to the issued permit. *This change was made to correct an error in the draft permit. Pursuant to 40 CFR 60.48b(k)(2), there are no NSPS standards for SO_2 emissions that apply to this boiler, because it would only fire natural gas.*

17. Condition 2.5.4(a)(i): This condition in the draft permit, which indicated that NSPS standards for PM and opacity would not apply to the proposed auxiliary boiler because its potential SO_2 emission rate would not exceed 0.32 lb/mmBtu, has not been carried over into the issued permit. The relevant NSPS does not set standards for PM emission or opacity from new boilers, like this boiler, that only fire natural gas. The cited criterion for the potential SO_2 emission rate of fuel is in fact relevant to the exemption from certain NSPS standards for SO_2 emissions, as addressed in Condition 2.5.4(a)(iii). *This change was made to correct an error in the draft permit.*

18. Condition 2.5.6: Several changes were made to this condition, which sets the permitted emissions of the auxiliary boiler.

    a. Limits are now set for VOM, individual HAP and total HAP. *Limits for these pollutants were established for this unit to better ensure that this project is not major for emissions of VOM and HAP.*

    b. The limits set for permitted emissions of the auxiliary boiler are lower, as they now reflect only address the emissions of the boiler itself. The limits for the auxiliary boiler in the draft permit overstated emissions as they reflected emission rates that applied to the combination of the solid fuel-fired boiler and the auxiliary boiler. *This change was made to correct an error in the draft permit.*

c. The averaging periods for the hourly limits are now specified. *It is appropriate that the averaging periods for these emission limits be specified, especially as the averaging period for the limits for NO_x and CO emissions, for which emissions monitoring would be conducted, is a 24-hour daily average.*