SIERRA CLUB PETITION

EXHIBIT 7

Illinois Environmental Protection Agency
Bureau of Air
October 2009

Responsiveness Summary for the Public Comments Period on a Construction Permit Application from Power Holdings of Illinois, LLC for a Proposed Synthetic Natural Gas Plant in Blissville Township, Jefferson County, Illinois

Source Identification No.: 081801AAF
Application No.: 07100063

Table of Contents

DECISION

On October 26, 2009, the Illinois Environmental Protection Agency (Illinois EPA) Bureau of Air issued a Construction Permit/PSD Approval to Power Holdings of Illinois, LLC for a new synthetic natural gas plant in Blissville Township, Jefferson County, Illinois. At the same time, the Illinois EPA issued this Responsiveness Summary for the public comment period that was held on the proposed issuance of this permit and the final permit decision on the application by the Illinois EPA.

BACKGROUND

Power Holdings requested a construction permit for a plant would use gasification technology to produce pipeline quality synthetic natural gas from Illinois coal. In coal gasification, coal is first gasified to produce a synthesis gas. The raw synthesis gas is then cleaned to produce a clean gas that is either used as fuel at the plant or further processed. At the proposed plant, the clean synthesis gas would be further processed by methanation to produce synthetic natural gas, which would be sold to natural gas suppliers. The design feedstock for the plant would be Herrin No. 6 coal from Illinois.

The construction permit issued for the project identifies the applicable rules governing emissions from the plant and establishes enforceable limitations on its emissions. The permit also establishes appropriate compliance procedures, including requirements for emissions testing, continuous emission monitoring, recordkeeping, and reporting. Power Holdings will be required to carry out these procedures on an ongoing basis to demonstrate that the plant 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 for permits for proposed sources of emissions. An air pollution control permit application must appropriately address compliance with applicable air pollution control laws and regulations before a permit can be issued. Following its initial technical review of Power Holdings' application, the Illinois EPA Bureau of Air made a preliminary determination that the application met the standards for issuance of a permit.

Because the proposed plant would be considered a major source, the Illinois EPA was required to hold a public comment period before issuing a construction permit for the plant. Accordingly, after it completed its preliminary review of the application, the Illinois EPA prepared a draft of the construction permit it was proposing to issue for public review and comment. As Power Holdings requested that the Illinois EPA hold a public hearing on the proposed issuance of a permit for the plant, a public hearing was scheduled as part of the public comment period. The public comment period opened with the publication of a notice in the Mt. Vernon Register-News on January 17, 2009. The notice was published again in the Mt. Vernon Register-News on January 24 and January 31, 2009. The public hearing was held on March 3, 2009 at the Knights of Columbus, 130 South Eighth Street in Du Bois to accept oral comments and answer questions about the proposed plant and the draft permit prepared by the Illinois EPA. The comment period was scheduled to close on April 2, 2009. Due to a request for comment period extension, the comment period was extended and closed on May 4, 2009.

Following the close of the public comment period, the Illinois EPA conducted its final technical review of Power Holdings' application. This review led to a final determination by the Illinois EPA that the application for the proposed plant met the standards for issuance of a permit.

AVAILABILITY OF DOCUMENTS

Copies of the Construction Permit/PSD Approval issued to Power Holdings for the proposed plant issued and of this Responsiveness Summary are available by the following means:

1. From the Illinois EPA's website:

   http://www.epa.state.il.us/public-notices/general-notices.html

2. By viewing documents at one of the following repositories:

C.E. Brehm Library 101 S. 7th Street Mt. Vernon, IL 62864	Illinois EPA, Marion Office 2309 W. Main Marion, IL 62959	Illinois EPA, Main Office 1021 N. Grand Ave., East Springfield, IL 62794
618/242-6322	618/993-7200	217/782-7027

3. By contacting the Illinois EPA by telephone, facsimile or electronic mail:

   Illinois EPA
   Bradley Frost, Office of Community Relations

   888/372-1996 Toll Free – Environmental Helpline
   217/782-7027 – Desk Line
   217/782-9143 – TDD
   217/524-5023 – Facsimile

   brad.frost@illinois.gov

APPEAL PROVISIONS

The construction permit being issued for the proposed plant includes approval to construct the plant pursuant to the federal rules for Prevention of Significant Deterioration of Air Quality (PSD), 40 CFR 52.21. Accordingly, individuals who filed comments on the draft permit or participated in the public comment period on the draft permit may petition the Environmental Appeals Board of the United States Environmental Protection Agency (USEPA) to review the PSD provisions of the issued permit. Other persons, who did not file comments or participate in the public comment period, may petition for administrative review only to the extent of the changes from the draft permit to the final permit decision. In addition, as comments were submitted on the draft permit for the proposed project that requested a change in the draft permit, 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 (CFR), "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:

United States 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 ILLINOIS EPA

1. The gasification technology used by the proposed plant would be experimental and risky.

   Gasification of coal for production of chemicals is an established and well demonstrated technology. Power Holdings indicates that it plans to use gasification technology from General Electric (GE). GE gasifiers are currently in use in the United States and around the world. Eastman Chemical in Kingsport, Tennessee, has been operating GE gasifiers for approximately 30 years to produce methanol, which is then used as the feedstock for production of a number of chemicals. A GE gasifier has also been operating in Coffeyville, Kansas since 2000 for production of hydrogen at an ammonia fertilizer plant.

2. "Syngas" is ten times dirtier than natural gas.

   This comment, which is unsupported, is not relevant to the proposed plant since the plant will produce Synthetic Natural Gas (SNG). SNG is chemically equivalent to natural gas. SNG should not be confused with syngas, which is the intermediate process stream at a gasification facility that is created by gasification of coal. Syngas is not used in its raw state but undergoes cleanup. The composition of syngas, especially its sulfur content, varies depending upon the design and operation of the cleanup systems at a facility.

3. I am confused about the nature of truck and rail traffic at the proposed plant.

   The plant is not being developed to receive coal by truck. In addition to receiving coal by rail, the proposed plant would ship its byproducts by truck and rail. Power Holdings indicates that it expects one rail shipment per day and no more than 10 truck shipments per day, Monday through Saturday. The major by-products shipped by truck and rail will be argon, nitrogen, and sulfuric acid. Power Holdings indicates that it will work with state and local highway departments to upgrade local roads and bridges as needed.

4. How many people will be employed per shift and in total at the plant?

   Power Holdings indicates that it expects about 50 people will be required to operate this plant on each shift. Since the plant will operate on a continuous basis, total employment would be about 250 people.

5. Were emissions from the plant during periods of startup, shutdown, and malfunction considered?

   Emissions from startup, shutdown, and malfunction were considered. They were appropriately addressed in the air quality impact analyses conducted for the plant. The permit includes requirements addressing emissions during startup, shutdown and malfunction.

6. Has the Illinois EPA considered the proximity of the proposed plant to nearby homes and the surrounding communities?

The proposed plant should not pose a threat to local ambient air quality, as considered by the Illinois EPA in permitting. Other aspects of the siting of the proposed plant, like other industrial land uses, are subject to appropriate zoning and land use planning, which are the responsibility of local governmental authorities.

7. Anytime there is industry and emissions to the atmosphere, there is going to be disease.

The fact that industrial plants have emissions is not a basis on which to deny a construction permit for the proposed plant. The purpose of air pollution control regulations and permitting is to help assure that emissions are appropriately controlled and public health is protected. Even in urban areas where there are air quality problems, the focus of efforts to improve air quality is on existing sources located in the urban area and on large, existing sources of emissions, like coal-fired power plants, which while located in areas that do not have problems with air quality, contribute to background levels of air quality so as to contribute to the problems experienced in the urban area.

8. What are "significant impact levels"?

The term "significant air quality impact levels" or "significant impact levels" (SILs) refers to specific numerical levels established by USEPA for criteria pollutants other than ozone, below which a project's individual impact on air quality is considered insignificant. For example, the USEPA has set a significant air quality impact level for NOx at a concentration of 1.0 microgram per cubic meter ($\mu g/m^3$), which is one percent of the NOx ambient air quality standards of 100 $\mu g/m^3$, measured as NO_2. As a modeling analysis of a proposed project evaluates its maximum ambient impacts, a finding that the impacts are below this level, i.e., 1.0 $\mu g/m^3$, means that the project should not meaningfully affect the existing air quality. In other words, air quality with the proposed source should be essentially unchanged from current levels and further modeling is not warranted. When used in this manner, the term really defines a level of impact that is numerically insignificant or trivial.

9. At the public hearing, references were made to air quality impacts "at the fence line." What does this mean?

The "fence line" is the same as the property line of the core facility, nominally a 160-acre area, which would be fenced to restrict unauthorized prevent public access. As public access to the area within the fence line would be restricted, air quality within the fence line is addressed by standards set by OSHA for worker exposure to pollutants. Air quality outside the fence line is subject to the National Ambient Air Quality Standards (NAAQS) set by USEPA to protect the public from exposure to pollutants. Accordingly, the evaluation of the air quality impacts of the proposed plant begins at the fence line where the status of the air changes from workplace air to ambient air.

10. I am concerned about the deposition of emissions from the proposed plant in the vicinity of the plant.

The emissions of the proposed plant would not pose a concern for deposition of pollutants in the vicinity of the plant and would pose limited concern generally for deposition. The plant

does not pose a concern for local deposition first because emissions would be assimilated in the atmosphere and dispersed. Then, PM, NO_x and SO_2[1], which are the bulk of the regulated pollutants emitted by the plant that undergo deposition, pose a direct threat to human health when they are in the air and can be inhaled. They no longer pose this threat when they are deposited on the surface of the earth and can no longer be inhaled. Emissions of CO emissions do not undergo deposition but gradually oxidize in the atmosphere transforming to CO_2, which then participates in the CO_2 cycle.

The more relevant issues for deposition are broader ones related to the contribution of the proposed plant to regional, continental and global loadings of certain pollutants. This is also another aspect of the effects of the proposed plant on air quality. However, these issues, which are not local ones, are addressed as the proposed plant's emissions of regulated pollutants would be very well controlled and such effects are or will be addressed by comprehensive regulatory program.[2]

11. I am concerned about the proposed plant because of the mercury that it would emit. Illinois residents have been warned not to eat fish from Illinois waters because of excessive levels of mercury, which is emitted by coal-fired power plants.

Emissions of mercury from coal-based facilities do not constitute a direct threat to human health. Rather, as observed by this comment, the mercury emitted by these facilities is a potential health threat as it bio-accumulates in aquatic environments, working its way up the food chain. Given these circumstances, it is important that people be aware of and understand the advisories that are issued by the Illinois Department of Public Health on consumption of fish caught from Illinois waters because of the levels of mercury (or other contaminants). In particular, Illinois issued its first statewide advisory for mercury contamination in 2001 as a protective measure given new studies indicating that consumption of fish with high mercury levels may pose a greater risk than previously thought for sensitive populations. These 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 species of fish taken from Illinois' waters. In addition, more restrictive advisories were given for certain species and/or sizes of fish and bodies of water, such as flathead catfish from the Ohio River.[3]

In addition, the sources that are of concern for Illinois' contribution to emissions of mercury are existing sources. This is because new coal-fired plants, like the proposed plant, are designed with modern control systems and emit a fraction of the mercury currently emitted by most existing plants per ton of coal used. Until recently, when 35 IAC Part 225, Subpart B, was adopted, Illinois' existing coal-fired power plants did not have any control

---

[1] NO_x and SO_2 gradually undergo chemical transformations in the atmosphere so they are generally deposited as nitrate and sulfate compounds.

[2] One example of such broad scale impacts would be the role of the proposed plant's emissions of NO_x and SO_2 in acid rain. Acid rain is the combined result of emissions of millions of tons of NO_x and SO_2 per year, principally from existing coal-fired power plants. This is followed by long-range transport, with some of the deposition occurring in environments that are sensitive to acid rain or acid deposition, commonly hundreds of miles away from the sources. Those emissions of NO_x and SO_2 and the issue of acid rain are being comprehensively addressed through the federal acid rain program, which addresses the emissions of both NO_x and SO_2 from both new and existing power plants. The emissions of NO_x and SO_2 from the proposed plant are addressed as they would be very well controlled.

[3] Further information on the fish advisory for mercury, as well as for advisories for contaminants in fish other than mercury, is available from Department of Public Health: www.idph.state.il.us/envhealth/fishadv/specialmercury.htm.

systems specifically for mercury emissions. Certain other states have also adopted or are adopting regulations for control of mercury at coal-fired power plants. USEPA will also be adopting a national program for control of emissions of mercury from power plants.[4] Even then, the magnitude of the reduction in mercury levels in freshwater fish is uncertain, as transport of mercury emissions occurs on a global scale.

12. How much mercury and other heavy metals would be emitted by the plant?

The plant's potential emissions of mercury are 0.0005 tons per year. The potential emissions of other heavy metals, primarily lead, would be 0.05 tons per year.

13. "Soot" and "smog" emitted from the plant would harm plants and trees.

The air quality impact analyses for the proposed plant show that the proposed plant would not have significant impacts on air quality. As such, the plant would not cause violations of the National Ambient Air Quality Standards (NAAQS). NAAQS are set at levels not only to protect human health, but also to protect public welfare, which takes into consideration protecting livestock and crops, as well as wildlife and vegetation from damage.

14. This area is already subjected to a major source of emissions with the existing Baldwin and new Prairie State power plants, so that the proposed plant should not be approved.

This is not a reasonable or legally supportable basis to deny a permit for the proposed plant. One of the functions of the permit process for a proposed major source is to consider the effect of that source and existing sources already in the area as necessary to confirm that the proposed plant will not cause or contribute to violations of air quality standards. The review of the proposed plant shows that the quality of the air would be protected.

In addition, the emissions of Dynegy's Baldwin power plant, which is about 40 miles from the site of the proposed plant, are going down. In 2005, settlement discussions between USEPA and others with Dynegy concerning the Baldwin power plant were successfully concluded with the entry of a Consent Decree. This Decree "locks" the Baldwin plant into operating at current emission levels, which are well below applicable standards, including operating its two selective catalytic reduction (SCR) systems for control of nitrogen oxides (NO_x) year-round. The Decree also requires that emissions of sulfur dioxide (SO_2) and particulate matter (PM) from the plant be further reduced with the installation of additional equipment to control emissions on a schedule that ends on December 31, 2012. The Decree also contains emission control requirements for the four other coal-fired power plants in Illinois operated by Dynegy.

The new Prairie State power plant, which is about 30 miles from the site of the proposed plant and is currently under construction, would be built with modern controls for emissions of NO_x, SO_2 and PM. The air quality analysis conducted as part of the processing of the construction permit for that plant showed that it would not threaten air quality.

15. I am concerned about emissions of coal dust from the plant.

---

[4] **USEPA adopted regulations (commonly known as the Clean Air Mercury Rule) that addressed mercury emissions from coal-fired power plants nationally that was expected to reduce their overall emissions of mercury by nearly 70 percent. However, the regulations were successfully appealed. USEPA must now initiate new rulemaking to address the legal deficiencies that were identified in its original regulations.**

The plant, as planned, would not have fugitive emissions of coal dust as coal would be handled in totally enclosed buildings. There would not be a large, outdoor storage pile for coal as is present at some existing coal-fired power plants.

16. The odors from this plant would be the same as those experienced with the gasification complex in the Beulah, North Dakota area, and the steel plant in the Granite City Illinois.

The Illinois EPA cannot confirm the presence of odors from the sources cited by these comments. There are other industrial facilities at both locations. However, the proposed plant is being designed to prevent nuisance odors. Comparing the proposed plant to older facilities that were developed before current concerns for odors is not appropriate. Older facilities may not have the modern processes and control measures that will be present at the proposed plant.

17. I am concerned about contamination and flooding of local streams and waterways.

Power Holdings indicates that the plant will be designed for Zero Process Water Liquid Discharge (Zero Discharge). Process water will be captured to be processed in the Water Treatment Facility and used or recycled at the plant.

Structures, concrete pads, and roadways will cover a portion of the site preventing rain from soaking into the ground. This stormwater will be collected and also processed for use at the plant. Power Holdings indicates that the retention ponds would be designed to hold at least twice the amount of water associated with the maximum rainfall measured in the area, about 6 inches of rain over a 24 hour period. The collection of this rainwater by the plant would generally act to reduce water runoff from the plant site, acting to reduce its potential contribution to flooding of nearby waterways.

18. I live near the plant site and am concerned about any ash ponds. There was a failure of an TVA ash pond recently that had deposited material over a large area with severe impacts on the downstream area. Ash ponds are not being scrutinized across the country.

Power Holdings indicates that there will be no ash ponds at the plant. The plant will produce a glass-like slag that will not be stockpiled at the plant. Accordingly, failures of ash ponds at the plant, as mentioned in this comment, could not occur.

19. If there is a chemical spill or contamination at the plant, what would happen?

If there were an immediate threat to plant personnel or the public from the spill, emergency personnel would respond and take or coordinate measures to protect against such threats. Following this initial response, actions would be taken to clean up the spill and prevent similar incidents in the future. This cleanup would be made easier as areas in which chemicals are stored or handled would be designed to contain any spills.

20. I live close to the plant and am concerned about the processes at the plant getting out of hand and causing safety problems.

The plant will have operational controls, systems and practices whose purposes include keeping equipment operating safely, which will serve to protect both the equipment and workers at the plant. The measures to protect the integrity and safety of equipment would

include emergency shutdown of pressure vessels as necessary to avoid structure failure, with "managed venting" of process gases to various flare systems, which would avoid the potential threat that would be present if those gases were released directly to the atmosphere. The companies that will provide insurance for the plant will mandate that these measures be utilized, with appropriate training of plant personnel in their use. These measures that will be in place at the plant to protect workers will also serve to protect the safety of the general public.

21. Would the local volunteer fire department be able to handle a fire or other emergencies or incidents at the plant?

Power Holdings would have to work with local emergency response officials to assure that the plant has been developed and contingency plans are in place to appropriately address the possibility of fire and other incidents at the plant. As such, the plant is similar to other major industrial plants that are located in Illinois' rural communities. Fire preparedness planning is dictated by the safety codes, which are enforced by insurance companies. These codes dictate how the plant must be developed and maintained to minimize the risk of fire and to enable any fire that might occur to be safely contained, controlled and extinguished. For example, the plant would have to maintain a reserve supply of water for the sprinklers and hydrants at the plant. Fire preparedness plans also routinely address the capabilities and appropriate roles of local response personnel. This includes the resources that would be available on a regional basis to help respond to incidents, as can be especially important for plants located in small rural communities.

At the same time, as implied by this comment, the initial and primary responsibility for fire protection and emergency response at the plant would likely be upon Power Holdings itself. In this regard, the presence of industrial facilities in small communities can improve the capabilities and resources of local services. Workers at facilities who receive regular training in firefighting or emergency response as part of their job share the benefits of this training, with the communities in which they live. Facilities also can support the purchase of emergency equipment for the community, so that it is available for both the community and the facility

22. People were concerned that an earthquake in the area could cause damage the proposed plant that causing safety problems, since there are a number of geological fault systems in the area.

As with industrial facilities in California and other areas that have frequent earthquakes, structural engineers now know how to design industrial facilities and pipelines to withstand earthquakes. Insurance requirements and Structural Steel Codes and Standards would require that the plant be designed in accordance with applicable design requirements for the classification of Seismic Zone. Similar requirements would apply to any new pipelines. These design requirements will protect the equipment from damage, thereby also protecting workers and the general public.

23. I am concerned about noise from the proposed plant.

Noise is not addressed by the air pollution control permit program. Noise is addressed by separate State regulations that were developed to protect people from nuisance noise, Title 35 IAC Subtitle H, Part 901. Noise from the proposed plant must be maintained or controlled to within the numerical standards set by these regulations. These standards are

applicable at the plant's property line and compliance can be verified by sound measurements once the plant is operational.

24. I am concerned about lighting. How is light pollution regulated?

Lighting and light pollution are matters that are under local jurisdiction. Light pollution can be managed by appropriate design of light fixtures, such as "shoebox" fixtures that shine down, not outwards.

25. I am concerned because I would live so close to the proposed plant. My neighbors and I very strongly believe that the value of our property will go down.

The Illinois EPA does not have a role in this aspect of the proposed plant. Under Illinois law, the siting of proposed plants is the responsibility of local government, which has the responsibility of addressing the effect of industrial development on property values through zoning and other legal mechanisms, as well as through "host agreements" with the developers or proposed projects.

26. The quality of life for the people in the area of the plant would be changed by the construction of this plant. People live in the area because of the peacefulness and sense of safety and security they enjoy.

These concerns dealing with the site selected by Power Holdings for the proposed plant are beyond the scope of the Illinois EPA's authority in permitting.

27. I am concerned about the traffic from the plant.

Truck traffic for the plant would be required to travel on designated truck routes. Any changes to the routing of truck traffic would be a matter under the joint jurisdiction of the Illinois Department of Transportation and local government authorities.

28. I am concerned about the amount of water used by the proposed plant, which will be supplied from Rend Lake, Does Rend Lake have the capacity to supply the plant or will Rend Lake shrink or even "dry up"?

Power Holdings indicates that it is confident that Rend Lake has adequate capacity to reliably supply water for the proposed plant. Rend Lake has a nominal total storage capacity of about 60 billion gallons. The use of water from Rend Lake is managed through an allocation process to maintain the water level in the lake. Power Holdings would obtain its water from an allocation of water to the State of Illinois that is specifically targeted for industrial development. As such, use of water by the proposed plant would not affect other allocations of water from Rend Lake, including the allocation of water to the Rend Lake Conservancy District and the allocation retained by the Corps of Engineers, under which the Corps maintain adequate flow of water down the Big Muddy River.

Power Holdings indicates that if the supply of water available for residential use were threatened, as could potentially occur with an extended drought, the water supply agreement with the State of Illinois would require Power Holdings to cut back or curtail its water use.

29. What role did USEPA play in the processing of the application and issuance of a permit for the proposed plant?

While the status of the Illinois EPA's review of the application was periodically discussed with USEPA, USEPA did not play a direct role in the actual processing of the application.

30. Has an Environmental Impact Statement been prepared for the proposed plant?

No. The proposed plant is not subject to a requirement that an environmental impact statement be prepared, i.e., it is not a federal project or a significant federal action.

31. How will permit limits be enforced?

Compliance with permit limits will be verified by the combination of emissions testing, monitoring systems, and recordkeeping that accompanies various limits, as set forth in both applicable regulations and conditions of the permit. These activities will be carried out by the plant and the results reviewed by the Illinois EPA. As the Illinois EPA cannot have someone at the plant at all times, it is appropriate that the primary burden for demonstrating compliance be put on the plant. In addition, the plant is under a general legal obligation to show that it is operating in compliance and to report any deviations to the Illinois EPA.

The Illinois EPA will oversee plant operations, including the various compliance activities carried out by the plant, by both periodic on-site inspections and review of the reports submitted by Power Holdings, to confirm compliance with applicable emission standards, other regulatory requirements and requirements of the permit.

32. The application for the proposed plant does not identify an operator for the proposed plant. Is this unusual? If the operator had a history of violations, would that affect the level of oversight of the plant by the Illinois EPA?

The fact that Power Holdings has not yet selected an operator for the proposed plant should not be considered unusual. For a large project, like the proposed plant, the selection of the company that would actually operate the plant can occur as part of the process of completing the contracts for the construction of a proposed plant, which has not yet occurred. In this regard, there are companies who have expertise in operating large plants of different types, and their involvement with a new plant typically begins at the construction stage. One factor in the reputation of such companies is their demonstrated ability to operate in compliance with applicable environmental requirements.

Accordingly, while the experience and past history of the operator at other sources might be a factor influencing the intensity of oversight of the plant by the Illinois EPA, the key factor would be the actual performance of this particular plant and its operator. If the plant has violations, has a small margin of compliance, or has difficulty in maintaining compliance, the level of oversight would be appropriately increased.

33. What will happen if there is a violation?

Violations will trigger an appropriate response by the Illinois EPA to ensure that public health and the environment are protected, appropriate corrective actions have been or will be taken to restore compliance and prevent similar incidents in the future, and, lastly, to

recover appropriate penalties considering the nature of the noncompliance and any economic benefits to source that resulted from noncompliance. In the unlikely event that the continued operation of the plant would poses a threat to public health, a injunction would be sought to bar further operation of the plant until the problem was corrected. In such case, or if penalties are appropriate or litigation is otherwise required, action would be taken against the plant by the Illinois EPA and the Illinois Attorney General's office, which acts as the Illinois EPA's attorney in litigation. In addition, if the violations involve falsification of testing or monitoring data or of records or the intentional submittal of false reports, criminal action could be directly taken against the individuals who were responsible. USEPA would also be available, either at the request of the state or on its own initiative, to assist in enforcement activities. USEPA could also independently undertake its own enforcement activities.

34. This permit should not be issued because the project might not be built.

The fact that this project may ultimately not move forward, as a result of future events or developments, is not a valid basis not to issue a permit for the proposed plant. To deny the permit, it would be necessary to show that Power Holdings in actual fact no longer intends to and has already "abandoned" its plan to build d the proposed SNG plant. This comment does not show this to be the case. The Illinois EPA also does not have any information that demonstrates this to be the case.

II. The Draft Permit Fails To Include BACT and Satisfy Air Quality Protections For PM2.5.

35. The draft permit does not include $PM_{2.5}$ BACT limits, nor does the record contain a Top-Down BACT analysis specific to $PM_{2.5}$. BACT limits are required for $PM_{2.5}$ by 40 CFR 52.21(j)(2) because $PM_{2.5}$ is a pollutant subject to regulation under the Clean Air Act that the proposed plant would have the potential to emit in significant amounts.[5] There is no legal or factual basis for Illinois EPA's failure to include a $PM_{2.5}$ BACT limit for each PM emission unit at the proposed plant. There are no longer any technical reasons preventing such limits. Proposed Rule, 72 FR 54,112 (Sept 12, 2007); *see also* 70 FR 66,043 (recognizing that the "practical difficulties" identified in the Seitz memo "have been resolved in most respects"). USEPA withdrew all guidance suggesting that PM_{10} could be used as a surrogate. 73 FR 28,321 (May 16, 2008). USEPA has also stayed the effectiveness of 40 CFR 52.21(i)(1)(xi), which allowed the limited use of PM_{10} as a surrogate for $PM_{2.5}$ for pending PSD applications.[6]

BACT for emissions of $PM_{2.5}$ is appropriately addressed by the draft permit. 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 plant,[7, 8] the Illinois

[5] The proposed plant would also be a significant source for emissions of $PM_{2.5}$ precursors, with emissions of more than 40 tons annually of SO_2 and NO_x.
[6] *See* Letter from Administrator Jackson to Paul Cort, Earthjustice (April 24, 2009).
[7] Because the permit application for the proposed plant 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, Power Holdings made its initial application submittal for a proposed SNG plant at a site west of Waltonville in Blissville Township on October 18, 2007.
[8] When USEPA adopted its revisions to the PSD rules to address emissions of $PM_{2.5}$, it also initially 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**

EPA considered $PM_{2.5}$ in its BACT determination. The draft permit included appropriate BACT limits that addressed emissions of $PM_{2.5}$. For emissions of $PM_{2.5}$, the BACT determination for the proposed plant 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 contain larger particles, which have an aerodynamic diameter greater than 2.5 microns, that are not $PM_{2.5}$. 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."[9] While BACT determinations are commonly made 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. From this perspective, it is particularly noteworthy that this comment has not challenged the determinations of BACT that was made for emissions of particulate matter for the proposed plant.

In this regard, BACT determinations were completed for all the emission units at the proposed plant that would emit particulate, including steam superheaters, the auxiliary boiler, startup heaters, flares, cooling towers, coal handling, and roadways. The BACT

---

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, 40 CFR 52.21(b)(50)(vi), which excludes condensable particulate from PM_{10} and $PM_{2.5}$ at the present time.)

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. 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 $PM_{2.5}$. 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. There is a dearth of $PM_{2.5}$ emission data for emission units based on actual testing and USEPA also has not finalized a reference test method for such testing. 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 units controlled with wet scrubbers.

[9] 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 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.

analyses for emissions of $PM_{2.5}$ for the project follows a very straightforward path. The auxiliary boiler, steam superheaters, and start-up heaters would all combust gaseous fuels. PM BACT for units firing gaseous fuels is commonly addressed by the quality of the fuel rather than by add-on PM controls. This is due to the low ash content and inherently low PM emissions from the combustion of gaseous fuels in properly operated units. As these combustion units would emit condensable particulate, the main precursors for the formation of condensable particulate NO_x and SO_2. BACT for NO_x and SO_2 emissions from these combustion units address the direct emissions of these pollutants and also serve to minimize formation of condensable particulate. A review of the RACT/BACT/LAER Clearinghouse (RBLC) has not identified units combusting gaseous fuels for which add-on controls were required. Accordingly, for these units, use of natural gas (including both "natural" natural gas and synthetic natural gas (SNG)) has been selected as BACT for particulate matter. Since the particulate matter emissions from all of these units should constitute $PM_{2.5}$, based on USEPA emission factors, the BACT determination for particulate matter in fact directly addresses emissions of $PM_{2.5}$.

Similarly, PM emissions from the CO_2 vent, sulfuric acid plant and flaring also involve combustion of process gas streams that will have low ash content and inherently low PM emissions. For the flares, this is because the flared streams will have undergone particulate matter cleanup, which is the first step in gas cleanup. The only circumstance in which raw syngas would be sent to a flare would be when there is an upset in a scrubber used for particulate cleanup, for the short period of time until excess pressure in the associated gasifier is relieved. In this case, absent cooling of the gas, which is another function of the scrubber, all gas sent to the flare would have undergone processing for removal of particulate. In addition, emissions of PM from flaring are controlled and minimized by the measures that generally restrict flaring at the plant.

For the cooling towers, PM emissions are the result of loss of water droplets from the cooling towers or "drift." These losses are controlled by requiring use of high-efficiency drift eliminators to minimize the loss of water droplets from the cooling towers. This serves to control emissions of $PM_{2.5}$, as well as PM and PM_{10}.

For material handling operations and roadways, in which particulate is generated by mechanical processes rather than by combustion, only filterable particulate would be emitted and $PM_{2.5}$ will only be a fraction of the PM_{10} emissions. As such, 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. In particular, for coal handling operations, BACT requires uses of baghouses with "nano-filter bags," with particulate emissions no more than 0.001 grains/scf.[10] (Refer to Condition 4.7.2(b)(ii).) This is a stringent level of performance for a baghouse.[11] Compliance with this requirement will necessitate effective control of emissions of $PM_{2.5}$. For roadways, road cleaning and dust suppression serve to control $PM_{2.5}$ as they remove silt and particulate from road surfaces preventing formation of $PM_{2.5}$.

[10] The USEPA's Environmental Technology Verification (ETV) Program has verified the effectiveness of new 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 $PM_{2.5}$.

[11] This is better than the best levels of performance for baghouses for coal handling reported in the RLBC, 0.004 gr/scf.

Incidentally, this comment misrepresents 40 CFR 52.21(j)(2). This provision states that a major project subject to PSD shall apply Best Available Control Technology for each pollutant subject to PSD.[12] It does not specify that a separate BACT limit must be set for each pollutant.

36. There is no legal or factual basis to assume that a PM (or PM_{10}) limit is equivalent to a $PM_{2.5}$ limit. The USEPA's adoption of $PM_{2.5}$ NAAQS reflects a finding that PM_{10} and $PM_{2.5}$ are not equivalent and NAAQS addressing $PM_{2.5}$ —rather than merely PM_{10} —were necessary to protect public health and welfare. That finding cannot be effectively undone, by substituting PM_{10} through a guidance document, based upon administrative expediency. Moreover, $PM_{2.5}$ is comprised of a larger faction of condensable particulates than is PM or PM_{10}, and controls for PM and PM_{10} are not necessarily controls for $PM_{2.5}$.[13] In addition, Power Holdings assumes that BACT for $PM_{2.5}$ is the same as the BACT for PM or PM_{10}.[87] This is technically incorrect and invalid. $PM_{2.5}$ and PM_{10} are different pollutants in so far as the size fraction affects control equipment and efficiencies differently. Thus, assuming that equipment designed and deemed appropriate as BACT for PM_{10} is also the same as BACT for $PM_{2.5}$ is erroneous. Power Holdings should conduct a separate BACT analysis for $PM_{2.5}$.

This comment does not demonstrate that the emission limits that were proposed as BACT for the particulate emissions of the proposed project, which are now 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 $PM_{2.5}$. 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.[14]

Moreover, 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." While BACT determinations are commonly made 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,

---

[12] "A new major stationary source shall apply best available control technology for each pollutant subject to regulation under the Act that it would have the potential to emit in significant amounts." 40 CFR 52.21(j)(2)

[13] *See* 73 FR 28,334; *In re So. Montana Elec. Generation and Transmission Coop., Highwood Gen. Station*, Slip. Op. at 9, 25-30 (Mont. Bd. Envt. Rev. May 30, 2008).

[14] **In addition, the approach taken by the Illinois EPA to the proposed plant's emissions of $PM_{2.5}$ is responsive to concerns that may underlay in 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 units at the plant are set in terms of PM and PM_{10}, so as to stringently limit the plant's emissions of $PM_{2.5}$.**

which would be an academic exercise merely to confirm that lesser ranked control technologies are indeed less effective.

37. Power Holdings incorrectly assumes that BACT for $PM_{2.5}$ is the same as the BACT for PM and PM_{10}.[15] This is technically incorrect. $PM_{2.5}$ and PM_{10} are different pollutants as particle size affects control equipment efficiency. Thus, assuming that equipment designed and deemed appropriate as BACT for PM_{10} is also the same as BACT for $PM_{2.5}$ is erroneous. Power Holdings should conduct a separate BACT analysis for $PM_{2.5}$.

Whether control measures are "appropriately designed" for $PM_{2.5}$, as compared to PM_{10} or PM, is a matter that should not be addressed as simplistically as suggested by this comment. This is because, as already discussed, $PM_{2.5}$ is a subset of PM_{10} and control measures for PM_{10} also serve to address $PM_{2.5}$. In addition, if the PM_{10} emissions of a unit are composed entirely of $PM_{2.5}$, there is no difference in a unit's emissions of PM_{10} and PM.

Incidentally, the portion of the application referenced by this comment does not directly support the characterization that was made of Power Holding's position on the nature of BACT for PM_{10} and $PM_{2.5}$, i.e., that they should be assumed to be identical. The particular portion of the application cited by the comment provided $PM_{2.5}$ emission data. In conjunction with that submittal, Power Holdings merely explained that it did not believe that the submittal of that data should result in any changes to the numerical BACT limits that had been proposed for the plant, which were expressed in terms of PM/PM_{10} for particulate and directly addressed emissions of precursors to $PM_{2.5}$.[16]

Also, PM, PM_{10} and $PM_{2.5}$ are not different pollutants because the efficiency of particulate control devices can be influenced by particle size. They are different pollutants because of the manner in which USEPA has adopted NAAQS for particulate matter, with separate NAAQS for different measurements of particulate in the atmosphere.

38. Preconstruction ambient air monitoring for $PM_{2.5}$ has not been conducted for the proposed plant. This is required by 40 CFR 52.21(m) before a PSD permit can be issued for the plant.

The Illinois EPA operates ambient air monitoring stations that provide $PM_{2.5}$ air quality data that is representative of current air quality at the site of the proposed plant and is sufficient to support the permitting of the proposed plant. The proposed plant would be located about halfway between two existing ambient monitoring stations[17] that show attainment of the current $PM_{2.5}$ NAAQS with sufficient margin of compliance to accommodate the proposed plant.

---

[15] *See* submittal titled $PM_{2.5}$ Permit Input, dated August 30, 2008, page 2.

[16] The only references to BACT on Page 2 on the August 30th submittal are "…since EPA is NOT making any changes to regulating BACT for $PM_{2.5}$, at this time, and since the Requested PM emissions are already utilizing BACT; then our $PM_{2.5}$ Emissions should also be considered BACT. … since BACT is applicable for direct $PM_{2.5}$ and SOx and NOx precursors; and since our requested SOx and NOx emissions are already BACT; then our precursor Emissions should also be considered BACT."

[17] The Illinois EPA operates ambient $PM_{2.5}$ monitors at Baldwin in Randolph County, approximately 40 miles west of the site of the proposed plant, and near McLeansboro in Hamilton County, approximately 40 miles to the east. In 2008, these stations monitored 98th percentile, 24-hour average concentrations of $PM_{2.5}$ of 20.8 and 25.7 µg/m^3, respectively, compared to the 24-hour NAAQS, 35 µg/m^3. In 2008, these stations monitored annual average concentrations of $PM_{2.5}$ of 10.4 and 12.4 µg/m^3, respectively, compared to the current annual NAAQS for $PM_{2.5}$, 15 µg/m^3. On a three year average, the 98th percentile, 24-hour average concentrations were 26.1 and 27.1 µg/m^3, and the annual concentrations were 12.0 and 12.1 µg/m^3.

39. The Illinois EPA has not modeled the $PM_{2.5}$ emissions from the proposed plant to demonstrate that the plant will comply with the $PM_{2.5}$ NAAQS and $PM_{2.5}$ increments, despite USEPA's instructions to do so.[18]

The Illinois EPA has assessed the impacts of the proposed plant on $PM_{2.5}$ air quality, using the results of the PM_{10} modeling for the proposed plant and data for existing $PM_{2.5}$ ambient air quality collected from monitoring stations operated by the Illinois EPA. This assessment shows that the plant would not cause violations of the NAAQS for $PM_{2.5}$, i.e., 15 µg/m^3, annual average, and 35 µg/m^3, 24-hour average (98th percentile value).[19, 20]

This assessment of $PM_{2.5}$ impacts for the proposed plant conservatively assumes that the $PM_{2.5}$ emissions of the plant are identical to the PM_{10} emissions, so that $PM_{2.5}$ impacts are identical to the PM_{10} impacts. (This assumption overestimates the plant's impacts for $PM_{2.5}$ as the majority of the emissions from roadways will not be $PM_{2.5}$.) The modeled plant impacts were then added to monitored background values. This is a reasonable approach given the nature of $PM_{2.5}$ air quality, the area in which the proposed plant is located, and the fact that the necessary tools and resources to support more refined modeling are not yet developed.[21] The results, as provided below, show that the proposed plant will not cause exceedances of the $PM_{2.5}$ NAAQS.[22]

---

[18] USEPA states that "…sources will be required to perform [air quality impact] analysis for the $PM_{2.5}$ NAAQS and, when finalized, $PM_{2.5}$ increments." 73 FR 28,336

[19] http://www.epa.gov/scram001/7thconf/aermod/aermod_mcb1.txt

[20] In an addendum to the preferred guideline model, AERMOD, in December 2006, USEPA provides guidance for compliance with the $PM_{2.5}$ NAAQS. The guidance states that "The design value for 24-hour averages is based on the high-eighth-high (H8H) averaged over N years, as an unbiased surrogate for the 98th percentile. The long-term design value for $PM_{2.5}$ is based on the highest annual average concentration averaged over N years." In this application, N is 5, corresponding to the 5 years of meteorology used in the analysis. The "design" value is that used for comparison to the NAAQS."

[21] Air quality for $PM_{2.5}$ is more regional in scale than air quality for PM and PM_{10}, which are more directly affected by the presence and emissions of individual sources. Regional levels of sulfates and nitrates consistently make up more than 50 percent of the ambient $PM_{2.5}$. As such, ambient monitors better represent existing air quality for $PM_{2.5}$, especially for the proposed plant, which would be located in an area that is rural in character. In addition, reductions in sulfate and nitrate concentrations are expected over the next couple of years due to emission reductions required by the Clean Air Interstate Rule. Finally, reliable inventories for $PM_{2.5}$ emissions of existing sources, as necessary for detailed modeling to be performed, have not been developed for areas that are in attainment of the $PM_{2.5}$ NAAQS. (Available resources have been directed to the development of such inventories in $PM_{2.5}$ nonattainment areas to support attainment planning.) The development of these inventories will be a gradual process as $PM_{2.5}$ is addressed as permits are renewed and emission testing begins to be conducted for $PM_{2.5}$ emissions.

[22] 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 85 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 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 should be no more than 25 percent of their PM_{10} emissions.

Incidentally, because of the factors already discussed with respect to $PM_{2.5}$ air quality and modeling, it would be appropriate for USEPA to initially set the SILs for $PM_{2.5}$ at Option 1. After a set period of time, the SILs could lower to Option 2 or to values slightly lower than Option 2. Option 3 would be overly restrictive and unduly burdensome.

$PM_{2.5}$ Impacts of the Proposed Plant ($\mu g/m^3$)

Averaging Period	Maximum Modeled Plant Concentration	Background Monitoring		Total Concentration	NAAQS
		Concentration	Location		
24-hour	2.87	26.1	Randolph Co.	28.97	35
		27.1	Hamilton Co.	20.97	
Annual	0.93	12.0	Randolph Co.	12.93	15
		12.3	Hamilton Co.	13.23	

USEPA has not yet adopted PSD increments in terms of $PM_{2.5}$, so "PSD increment modeling," as suggested by this comment, is not possible for the proposed project. When PSD increments are adopted for $PM_{2.5}$, in the unlikely event that these increments apply retroactively, the assessment of $PM_{2.5}$ impacts from the proposed plants suggests that the plant would comply with the PSD increments.[23] In this regard, the proposed plant would be the first major source permitted in the area after the major source baseline date for $PM_{2.5}$ and would be the only source in the area that would consume PSD increment for $PM_{2.5}$, rather than being part of the baseline.

40. Power Holdings has provided unsupported estimates of only filterable $PM_{2.5}$ emissions in a submittal dated August 30, 2008. However, this submittal did not address the condensable fraction of $PM_{2.5}$. Power Holdings apparently believes that because USEPA did not address condensable $PM_{2.5}$ in its May 8, 2008, rulemaking for $PM_{2.5}$, condensable $PM_{2.5}$ emissions need not be estimated or accounted for. However, since emissions of condensable $PM_{2.5}$ are significant (in many cases the majority of the $PM_{2.5}$ emissions), assuming condensable $PM_{2.5}$ emissions to be zero is not appropriate. Total $PM_{2.5}$ emissions, which are the combination of filterable and condensable $PM_{2.5}$ emissions, must be determined and an air impact analysis conducted.

Power Holdings did address the condensable fraction of particulate matter in its application and emissions of condensable particulate were addressed in air quality modeling. The Emissions Summary on Pages 8-1 and 8-2 of Power Holdings' submittal of October 21, 2008 provides data for emissions of filterable particulate, condensable particulate, and total particulate matter. All particulate matter, including both filterable and condensable, was included in the modeled emission rates.[24] For example, for the Auxiliary Boiler, Page 2-1 shows modeled PM emissions of 13 lb/hr, which is a rounded value of the total PM emissions of the Auxiliary Boiler PM, 12.791 lb/hr, as shown on Page 8-1.[25] The updated modeling, which also addressed on-site facilities for handling coal, also used the emission data for total particulate matter, including both filterable particulate and condensable particulate.

This comment inappropriately focuses on Power Holdings' August 30, 2008 submittal, without consideration of other information on condensable particulate emissions that was

---

[23] USEPA has proposed several options for PSD increments for $PM_{2.5}$ but has not yet completed the relevant rulemaking. Refer to proposed rulemaking "Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$) – Increments, Significant Impact Levels (SILS) And Significant Monitoring Concentration (SMC)," 72 FR 54112 (September 21, 2007).

[24] The relevant emission rates for particulate matter and other pollutants used for the air quality modeling for the proposed plant, which addressed emission units that would emit condensable particulate, are provided on Pages 2-1 thru 2-9 of Power Holdings' submittal of October 17, 2008.

[25] Refer to the Emissions Summary, Pages 8-1 and 8-2, of the October 21, 2008 submittal.

provided elsewhere in the application. In this regard, the specific purpose of the August 30, 2008 submittal was to provide information on emissions of <u>filterable $PM_{2.5}$</u>, which had not previously been addressed, unlike condensable particulate, which had been. The August 30, 2008 submittal included adequate support for the emission data for $PM_{2.5}$, given the state of data generally for emissions of $PM_{2.5}$ and the fact that the $PM_{2.5}$ emission data for the plant was derived from the emission data for PM_{10}.

41. An applicable state rule, 35 IAC 201.141, prohibits the Illinois EPA from granting a construction permit for the proposed plant without first determining that the plant would not "cause or threaten or allow the discharge or emission of" $PM_{2.5}$ "into the environment… so as, either alone or in combination with other sources, to cause or tend to cause air pollution in Illinois.". The term "air pollution" means "the presence in the atmosphere of one or more air contaminants in sufficient quantities and of such characteristics and duration as to be injurious to human, plant, or animal life, to health …" 35 IAC 201.102. There has been no analysis of $PM_{2.5}$ impacts from the proposed plant.

As already discussed, there has been an assessment of the impacts of the proposed plant on $PM_{2.5}$ air quality. This assessment shows that the plant would not cause a violation of the $PM_{2.5}$ NAAQS. As such, the plant should not be considered TO be a threat to human health or the environment.

42. The current NAAQS for $PM_{2.5}$ were challenged and have been remanded back to the USEPA as insufficient to protect public health and the environment.[26] As such, they do not serve to prevent "sufficient quantities… and duration as to be injurious to human, plant, or animal life," as required by 35 IAC 201.141. Before issuing a permit, The Illinois EPA must first identify the $PM_{2.5}$ concentration that will satisfy 35 IAC 201.141 and then determine that emissions from the proposed plant "either alone or in combination with other sources" will not exceed that standard.[27] That has not been done for the proposed plant.

It would be inappropriate for the Illinois EPA to establish an ambient air quality standard for $PM_{2.5}$ in the context of permitting of a specific project, as effectively requested by this comment. In Illinois, ambient air quality standards are rules and are appropriately established through rulemaking by the Pollution Control Board, not the Illinois EPA. Similarly, at the national level, ambient air quality standards are adopted by the USEPA.

At the same time, the proposed plant should not cause concentrations of $PM_{2.5}$ in the atmosphere that would be injurious to human, plant or animal life. In Illinois, elevated levels of $PM_{2.5}$ in the atmosphere, which pose a potential threat to human health and welfare, are associated with urban areas, not with rural areas. The reductions in emissions that are needed to reduce ambient concentrations of $PM_{2.5}$ in urban areas will have the secondary effect of further improving air quality in rural areas.

43. BACT for $PM_{2.5}$ must consider limits that reflect the Lowest Achievable Emission Rate, which includes consideration of the most stringent standards found in any SIP. Therefore, the $PM_{2.5}$ BACT limits must also consider $PM_{2.5}$ emission rates that comply with 35 IAC 201.141.

This comment touches on one of the obstacles that currently exist for determining BACT for particulate matter with limits expressed in terms of $PM_{2.5}$. This is the absence at this

[26] American Farm Bureau Federation v. EPA, Case No. No. 06-1410, Slip Op. (D.C. Cir. Feb. 24, 2009).
[27] *See also* Section 165(a)(3)(A) and (C) of the Clean Air Act.

time of emission limits and standards that are expressed in terms of $PM_{2.5}$. Thus, even if the proposed project were located in a nonattainment area for $PM_{2.5}$ and subject to a requirement for LAER, which it is not,[28] there would be no SIP limits for $PM_{2.5}$ that could be considered in a LAER determination. The determination of LAER for $PM_{2.5}$ would only entail an evaluation of emission limits that are achievable with available control technology. This is identical to the determination of BACT, which is applicable to the plant.[29]

44. Scientific evidence exists that the current $PM_{2.5}$ NAAQS are not sufficiently protective of public health, especially for young children and the elderly. USEPA staff and the Clean Air Scientific Advisory Committee have suggested an annual $PM_{2.5}$ NAAQS lower than 15 ug/m^3.[30] USEPA staff has pointed to health studies that suggest annual $PM_{2.5}$ concentrations should be limited to below 13 µg/m3.[107] USEPA staff has also recommended a daily $PM_{2.5}$ NAAQS at the "middle to lower end" in a 25 to 35 ug/m^3 range (i.e., 25 to 30 ug/m^3).[31] USEPA staff noted that short-term studies are relevant to determining the annual concentrations protective of public health and that "the strongest evidence for short-term $PM_{2.5}$ effects occurs at concentrations near the long-term (e.g., annual) average." (*See* Final Rule: National Ambient Air Quality Standards for Particulate Matter, 62 FR 38,652, June 1, 1997.) Illinois EPA's analysis under 35 IAC 201.141 must account for the scientific evidence that concentrations below 15 µg/m^3 may be a threat to public health.

The assessment of $PM_{2.5}$ impacts for the proposed plant responds to the matters described in this comment. As already explained, with the proposed plant, the maximum annual ambient concentrations of $PM_{2.5}$ in the area should be no more than about 13 µg/m^3, significantly lower than 15 µg/m^3. As measures are implemented to reduce ambient concentrations of $PM_{2.5}$ in urban areas, concentrations of $PM_{2.5}$ throughout the state will also be reduced.

45. Maximum hourly flaring emissions have not been modeled. Power Holdings acknowledges this, noting that "…nevertheless; showing the maximum possible combination of SO_2 that could possibly occur during any one, single hour in any year may not be helpful or indicative of a realistic condition and overly conservative."[108] Modeling worst case conditions is required. Unless modeling is done with hourly maximum flaring emissions (or the permit prohibits flaring), a permit cannot be issued. [32]

---

[28] Both federal and state law and rule direct applicability of LAER to proposed projects that would be located in a nonattainment area for a particular criteria pollutant. The proposed project is not located in a nonattainment area for $PM_{2.5}$ (or any other criteria pollutant). This fact is not altered by the current status of the NAAQS for $PM_{2.5}$. It is certainly not affected by 35 IAC 201.141, which is a state rule that addresses acceptable levels of emissions from emission units as related to their impacts and is unrelated to the control technology that is used on emission units.

[29] In addition, as emission standards and limits that are expressed in terms of $PM_{2.5}$ do not currently exist, there is also a lack of actual measurements and data for emissions of $PM_{2.5}$. While this situation will change over time, as such data is gathered, such data is not available for the permitting of the proposed project.

[30] *See* Office of Air Quality Planning and Standards (OAQPS), USEPA, Review of the National Ambient Air Quality Standards for Particulate Matter: Policy Assessment of Scientific and Technical Information (Staff Paper) § 5.3.1.1, at 5-7 (2005); Letter from Dr. Rogene Henderson, Clean Air Scientific Advisory Committee, to Administrator Stephen L. Johnson, USEPA 3–4 (Mar. 21, 2006) ("Studies described in the PM Staff Paper indicate that short term effects of $PM_{2.5}$ persist in cities with annual $PM_{2.5}$ concentrations below [15 µg/m3]").

[31] OAQPS Staff Paper Section 5.3.5.1, at page 5-32,. "[S]taff continues to believe that an annual standard cannot be expected to offer an adequate margin of safety against the effects of all short-term exposures." *See* also Sections 5.3.4.1, at pages 5-22–23, and 5.3.7, at page 5-46.

[32] *See* 70 FR 68,218, 68,240 (Nov. 9, 2005) (codified at 40 CFR Part 51 Appendix W, Section 8.1.2.a) ("As a minimum, the source should be modeled using the design capacity (100 percent load)." Also see *In re Northern Michigan University*, PSD Appeal No. 08-02, Slip. Op. at 48-49, 53 (EAB Feb. 18, 2009). Also refer to pages C-44 to 46 of the USEPA's *New Source Review Workshop Manual,* Draft October 1990 (NSR Manual).

Maximum hourly SO_2 emissions associated with a flaring event have been modeled, as discussed in a subsequent version of the Flare Emissions – Evaluation, dated November 12, 2008, a preceding August "22-28" submittal, and the submittal dated October 21, 2008. In particular, the "Start-Up and Malfunction Conditions" shown on Pages 8-1 and 8-2 of the October 21, 2008 submittal show that maximum hourly flare emissions were modeled. The resulting modeled impacts were all below Significant Air Quality Impacts.

This comment refers to the first version of the Flare Emissions – Evaluation. In this document Power Holdings was trying to explain that hourly limits on SO_2 emissions from flaring were not necessarily meaningful. This was because the emergency shutdowns of a cleanup train, which would be accompanied by the maximum emissions of SO_2 from a flare, would be an uncommon occurrence. In addition, such events would likely occur in less than one hour, ideally in only about 30 minutes. The subsequent revised Flare Emissions – Evaluation, dated November 12, 2008, does not include the statement quoted in this comment as it was recognized that it was neither relevant or informative.

46. Emissions of hydrogen sulfide (H_2S) and carbonyl sulfide (COS) during flaring were not considered in the evaluation whether the proposed plant would be a major source of HAPs. This evaluation also fails to consider any other HAPs that may be emitted from the flares. As such, the evaluation of the potential emissions of HAPs underestimates emissions and the plant most-likely is a major source for HAPs. For this reason, and for reasons set forth in my other comments, the proposed plant appears to be a major source of HAPs for which a case-by-case determination of Maximum Achievable Control Technology (MACT) is required.

The evaluation of the potential HAP emissions associated with flaring has been properly performed. As reflected in Condition 4.1.6(b) of the permit, flaring will have a minimal contribution to the HAP emissions of the proposed plant. H_2S, which will be the predominant form of sulfur in flared gas, constituting over 90 percent of the sulfur compounds in the gas by weight, is not a HAP and is not a factor in whether the plant is a major source of HAPs. Along with methanol and other organic HAPs, the emissions of COS were addressed in the application and considered in the evaluation whether the plant would be a major source of HAPs. The emissions of COS from flaring are limited to 0.06 tons per year.[33]

As a general matter, the permitted emissions of the proposed plant overall are below 10 tons per year for any individual HAP and less than 25 tons per year for all HAPs. As such, the plant is not a major source for HAPs and a case-by-case determination of MACT is not required for the plant pursuant to Section 112(g) of the Clean Air Act.

47. Power Holdings appears to rely on the future existence of Flare Minimization Plans, which have not been developed, to limit emissions from flaring. If these plans are to be used in any way in the permitting process, they must be developed, reviewed by Illinois EPA, and provided to the public for review and comment along with the draft permit. In particular, this is required by 40 CFR 124.10(d)(vi). Also, in the case of *In re RockGen Energy Center* (8 E.A.D. 536, 552-55, EAB 1999), the EAB found that permit provisions requiring a "post-permit plan" to be submitted

[33] Condition 4.1.6(a) of the issued permit limits total annual emissions of methanol, individual HAPs other than methanol, and total HAPs from the flares to 0.10, 0.06 and 0.19 tons per year, respectively. Accordingly, as COS is an individual HAP, emissions of COS are limited to 0.06 tons year. Note that the draft permit would have erroneously set a limit of 0.09 tons per year for total HAPs, which would not account for emissions of methanol. This error has been corrected in the issued permit.

by a source were invalid. The EAB required the permitting authority to subject any provisions relied upon for permitting to public notice and comment.

The permit properly imposes requirement on the source for "Flaring Minimization Planning"[34] on an ongoing basis. Flaring minimization planning works to reduce flaring by evaluating the reasons for flaring that actually occurs and identifying actions that can and should be taken to reduce or eliminate subsequent flaring due to similar causes. To support this effort, Flare Minimization Plans must be prepared describing various equipment and operational aspects of the flares at the plant, with the development of the initial plan to occur in the future prior to startup of the plant. Further event-specific investigation, reporting and corrective actions are required for flaring incidents, defined as flaring that accompanies the unscheduled shutdown of a gas processing train, with the goal of identifying the root cause of such flaring and taking actions to reduce similar flaring incidents in the future.

The provisions for flaring minimization were set forth in the draft permit and were available for review and comment by the public. These provisions are based on regulations adopted in other jurisdictions to reduce emissions from existing sources.[35] Those regulations apply on an ongoing basis in generally the same manner that they would apply to the proposed plant. The requirements for such planning also do not serve in place of requirements for flaring that are properly addressed during the processing of the construction permit application for the proposed plant, which also were addressed in the draft permit.[36] Most significantly, other than the portion of startup before coal is introduced into the gasifiers,[37] flaring of process gas streams is not allowed during normal operation of the gasification process (See Condition 4.1.2-1(b)(iii)). The permit also sets limits on the overall emissions from flaring (See Conditions 4.1.2-1(d)), accompanied by requirements for monitoring and recordkeeping to verify compliance with those limits.

The material cited in this comment does not support the premise that Flaring Minimization Plans should have been developed and submitted as part of the application for the proposed plant. 40 CFR 124.10(d)(vi) merely addresses the availability of the administrative record relied upon by a permitting authority for the processing of a permit application. It does not specify that documents such as Flaring Minimization Plans for the proposed plant must be part of that record. The circumstances and type of plan addressed by the EAB in *In re RockGen Energy Center* are different from the Flaring Minimization Plans that must be periodically prepared for the proposed plant. In that case, the Plan would have served as an exception to BACT limits set in the PSD permit.[38]

---

[34] **The Flare Minimization Plan requires Power Holdings to further reduce flaring and associated emissions once the plant begins operation. This is to be done by analyzing the cause of flaring events that do occur and taking further steps to eliminate or reduce them. (See Conditions 4.1.2-1(c)(i), 4.1.2-1(c)(ii), 4.1.5-2(a)(i) and 4.1.5-3 of the permit. Also see the requirements of 40 CFR 63.6(e)(1) and (e)(3), as addressed by Condition 4.1.5-2 of the permit.)**

[35] **The key precedent for the provisions for flaring minimization is a regulation adopted by the Bay Area Air Quality Maintenance District (BAAQMD) for flaring at existing refineries in the San Francisco Bay Area, Regulation 12: Miscellaneous Standards Of Performance, Rule 12: Flares At Petroleum Refineries. These rules address operating facilities to identify and implement measures to further minimize flaring.**

[36] **See Conditions 4.1.2-1(b)(iii) and (b)(vii), 4.1.3(c)(i), 4.1.5-1(b), and 4.1.10(c).**

[37] To minimize or control emissions during the initial stage of the startup of gasifiers, alcohol is used as the feedstock until the operating pressure of the gasifier reaches that of the gas cleanup train. Only when this pressure is reached and raw syngas is being processed by the gas cleanup train, may coal feedstock be introduced into the gasifier. (See Condition 4.1.2-1(b)(v).)

[38] **In *RockGen*, the Permittee would have been allowed to prepare a start-up and shut-down plan at a later date (no later than four months prior to initial operation of the facility). If Wisconsin DNR approved the plan, the applicant would be allowed to exceed the BACT limits during start-up or shut-down. This is much different than the required flare minimization planning, whose purpose is to further reduce emissions and does not relax any established emission limits.**

48. The Flaring Minimization Plans should be developed now, when the plant is in the design stage, since minimization of flaring is not simply an operational issue to be addressed after the plant is built. Rather, minimization of flaring involves plant design and philosophy, material selection, instrumentation and controls, and other factors that must be designed and planned for now before the plant is built to truly minimize flaring at the plant.

As already discussed, the permit properly addresses Flaring Minimization Planning as an activity that occurs after the design and construction of the plant is complete, when the proposed plant begins operation and thereafter. The permit also includes other provisions that address the development and design of the plant to prevent and minimize flaring. In particular, the permit generally does not allow routine flaring of process gas streams. (See Condition 4.1.2-1(b)(iii).) Except for initial startup of gasifiers with alcohol feedstock, flaring is only allowed for upsets or malfunction events. As defined by 40 CFR 63.2, malfunctions are failures of equipment that that are not reasonably preventable[39] and, accordingly, exclude events that can be foreseen and addressed in the development and design of the proposed plant.

Moreover, Flaring Minimization Planning, as addressed by this comment, is an activity that cannot be conducted at this time. First, the detailed design of the plant, which would be necessary for the preparation of the initial Flaring Minimization Plan, has not yet occurred. In addition, the Plan addresses operation and maintenance procedures, which while important to the prevention of flaring, cannot be prepared until after the plant is designed and equipment is selected [40] Accordingly, the permit addresses requirements or specifications that the plant will have to meet. Then, as routine flaring is not allowed by the permit, the focus of Flaring Minimization Planning is to track and address flaring events that could not be foreseen and addressed during the construction and development of the proposed plant. It is inherent that such events will be identified by their actual occurrence and must then be addressed on an event-specific basis.

49. Power Holdings uses a destruction efficiency of 99 percent for flaring. However, there is no basis for this assumption and nothing in the record to support it. Such a high efficiency is very unlikely. In addition, the record does not contain design or operational details for the flares of the type necessary to ensure that the flares will consistently achieve 99 percent efficiency.

This comment ignores the supporting USEPA documents referred to in the application that support use of a flare destruction efficiency of 99 percent. In particular, the application refers to the *Flare Efficiency Study*, EPA-600/2-83, July 1983, and *Basis and Purpose Documents on Specifications for Hydrogen Fueled Flares*, March 1998.[41, 42] As shown in

---

[39] As defined by 40 CFR 63.2, "*Malfunction* means any sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions."

[40] As this permit for the proposed plant identifies applicable requirements and sets BACT, this permit and associated permitting process address the "specifications" that the plant must be designed to comply with. The detailed, engineering design of the plant will be conducted to meet those specifications. Given the magnitude and nature of this project, it is not practical to design the proposed plant before the specifications for the plant are established with the issuance of a construction permit for the plant.

[41] Refer to page 7 of the August 22-28, 2008 submittal.

[42] USEPA addressed the destruction of H_2S by flaring in Evaluation of the Efficiency of Industrial Flares: H_2S Gas Mixtures and Pilot Assisted Flares, USEPA September 1986 (EPA-600/2-86-D80). As reported in Table 2-1, H_2S is readily destroyed by flaring. The lowest reported flare destruction efficiency for H_2S is 99.7 percent. The destruction

Table 1 of the *Flare Efficiency Study*, flare combustion efficiency is consistently greater than 99 percent for properly operated flares. As shown in Figure 1 of *Basis and Purpose Documents on Specifications for Hydrogen Fueled Flares*, this is particularly true for gas streams that contain significant levels of hydrogen, as would be the case for the process gas streams in the gasification block.

50. The record does not contain design or operational details for the flares of the type necessary to ensure that the flares will consistently achieve 99 percent efficiency. Flares are not typical control devices as they do not continuously assure a specified, measurable, control efficiency because they cannot assure a minimum residence time and minimum temperature, which are both critical for destruction efficiency. In other words, flares cannot assure a minimum level of destruction efficiency, which would represent an enforceable "worst case" emission rate. Therefore, an assumption that the flares at the plant will *always* achieve at least 99 percent efficiency is not enforceable and is unreasonable. It results in vastly under-calculating the emissions that will actually occur from flaring at the proposed plant.

While the destruction efficiency of a flare is not measurable in day-to-day practice, the operational requirements imposed on the flares ensure that flares consistently achieve a minimum level of destruction. This approach is consistent with the common practice for emission units and control devices for which continuous emissions monitoring is not performed. In particular, requirements are set for the minimum heat content of gas that is flared and the maximum velocity of this gas as it exits the flare tip and is combusted. The combination of these requirements serves to address effective combustion as the temperature of combustion is indirectly addressed by the requirement for a minimum heat content in the flared gas. Residence time is addressed by the requirements for a maximum velocity or rate at which the gas exits the flare tip. These requirements are applicable for all flaring that occurs.

51. It appears that NO_x emissions from flaring are significantly understated. This is because the flares at the proposed plant would be nitrogen-assisted[112] and thermal NO_x formation is significantly increased by the presence of nitrogen at high temperatures. The emission calculations for the flares do not account for the additional NO_x formation due to the flares being nitrogen assisted. I have been unable to calculate by how much because the application does not provide the technical basis for the NO_x emission calculations. This undermines the public review and comment process and indicates that Illinois EPA's review has been incomplete. At a minimum, the technical basis of calculations must be provided, reviewed by Illinois EPA, and made available for public comment.

The NO_x emissions of the flares have not been understated as suggested by this comment. There will not be a quantifiable difference between the NO_x emissions of the proposed flares which would be nitrogen assisted, and the NO_x emissions of an air-assisted flare. This is because nitrogen is the primary constituent of air, making up 78 percent by volume of the atmosphere. Use of an assist stream to a flare that is 99 percent nitrogen will not make a difference in the determination of NO_x emissions from the flare, compared to use of an assist stream that is only 78 percent nitrogen. The applicable USEPA methodology for calculation of NO_x emissions from flares does not distinguish between steam-assisted flares, in which the assist stream has no nitrogen, and air-assisted flares.

---

efficiency of a flare for H_2S can be better by an order of magnitude than the destruction for organic compounds, i.e., 99.99 percent destruction efficiency of H_2S, compared to 99.9 percent destruction efficiency for organic compounds.

52. The SO_2 emissions from the flares have been significantly underestimated. Power Holdings recognizes that significant SO_2 emissions can result from flaring during malfunction periods.[43] The assumed emission rates for purposes of setting BACT limits and modeling air impacts do not represent worst-case conditions.

Potential SO_2 emissions from flaring were calculated based on planned operation of the plant with only a small allowance for flaring due to upsets and unplanned events.[44] This is appropriate as BACT requires that flaring from the plant be minimized. While the permit may as a result set stringent limits on the SO_2 emissions that may occur from flaring, this does not demonstrate that SO_2 emissions have been underestimated. Moreover, the comment does not provide any basis for its assertion that SO_2 emissions are underestimated, other than pointing to the maximum hourly emission rate during individual flaring events. The comment also does not provide alternative recommendations for the number of unplanned flaring events that should be considered when calculating potential emissions from flaring.

53. The application dismisses the value of continuous monitoring related to flared gas,[114] such as the sulfur content of flared gas. Accurate operational data, as would be made possible by such monitoring, is necessary to determine the actual emissions of SO_2 during flare events. The need for accurate data for flared gas streams has been recognized by regulatory agencies. For example, such monitoring is required for flares in refineries in California, as part of assessing flaring emissions, which in turn is used for the development of flare minimization strategies. To the extent that "Flare Minimization Planning" is required of the proposed plant, effective implementation of such planning will require accurate data quantifying emissions from flaring malfunctions. However, the SO_2 emissions rates for purposes of setting BACT limits and modeling air impacts are unenforceable.

The draft permit would require operational monitoring, as recommended by this comment, to support accurate determinations of the SO_2 emissions from flaring. In particular, Condition 4.1.8-2 requires monitoring for the volume of process gas that is flared and its sulfur content.[45] These requirements are carried over in the issued permit. As a result, SO_2 emission limits set for flaring, including the numerical BACT limits set for annual SO_2 emissions from flaring, will be enforceable. Emission data will also be available to support implementation of requirements for ongoing minimization of flaring.

While the statement in the application cited in this comments could be read to suggest that Power Holdings argued that monitoring of flare gas streams was not needed, those statements must be considered in context. In this regard, this comment refers to statements of Items Q and R, on pages 9 and 10, of the August 22-28, 2008 Submittal. As explained in the introduction to that material, Power Holdings was providing a theoretical response to comments about flaring that could potentially be made in public comments.

[43] For example, maximum hourly emissions of SO_2 from the syngas flares and the acid gas flares are indicated to be 9510 and 9508 pounds, respectively, in the November 5, 2008 submittal.

[44] In addition to normal startups and shutdowns of units associated with needed periodic maintenance, the calculations for flaring emissions are based on a total of only 12 unplanned flaring events per year for the four flares at the plant (i.e., four events due to upsets in acid gas cleanup, four events due to upsets in methanation, and four events due to upsets of a sulfuric acid plant).

[45] In particular, Condition 4.1.8-2(a) provides that "The Permittee shall install, operate and maintain continuous monitoring systems on each affected flare related to the discharge of process gas (i.e., syngas or acid gas streams but not fuel for the pilot flame or purge gas) to a flare for the following parameters. These monitoring systems shall be operated in accordance with relevant provisions of the NSPS, 40 CFR 60.107(a): (i) The total flow of process gas sent to the flare (SCFM); (ii) The H2S and CO content of the process gas sent to the flare (ppm)."

54. The calculations for fugitive VOM emissions from leaking components in the application appear to be based on average emission factors for SOCMI sources, i.e., Table 4.5-1 in Section 5 of Equipment Leaks: *Preferred And Alternate Methods for Estimating Fugitive Emissions from Equipment Leaks, Volume II, Chapter IV of the Emission Inventory Improvement Program, November 1996*. These factors are inappropriate for calculating potential emissions. If actual emission data are not used, at a minimum, emissions should be based on the appropriate screening values provided in Table 4.4-3 in Section 4 of this document, "Preferred Method for Estimating Emissions."

Appropriate emission factors were used to calculate the potential emissions from leaking components. This comment correctly observes that the calculations for VOM emissions from leaking components were based on the average factors from Table 4.5-1 in Section 5 of the cited document.[46, 47] As explained in that document, when screening data, i.e., actual field data for the concentration of VOM in the air next to components at a source, is available use of emission factors from Section 4 is preferable.[48] However, because site specific screening data cannot be available for a source that is only proposed and has not yet been constructed, the factors in Table 4.4-3 cannot be used for the proposed plant. Accordingly, use of the emission factors from Table 4.5-1 is appropriate to determine the VOM emissions of the proposed plant. Moreover, as the emission factors in Table 4.5-1 do not account for actual data for the number and magnitude of leaking components, as would be reflected in measured screening values, these factors are reasonably used to address the potential emissions of VOM from the proposed plant.

55. The application provides calculations for fugitive VOM emissions from leaking components in summary fashion.[49] For example, total VOM fugitive emissions are estimated to be 2.46 tons/year, of which methanol is 1.79 tons/year.[50] However, the calculations for methanol emissions from leaking components are not provided to explain why methanol makes up only 1.79 tons/year of the total VOC emissions of 2.46 tons/year.

The application provides an acceptable level of detail in the calculations for VOM emissions from leaking components. For each category of component and service, separately for components in continuous operation and component in loading/unloading activities, the application provides data for emission factor, VOC:TOC ratio, number of components, level of control provided by the LDAR program, annual hours of operation, and annual

---

[46] As specifically noted in Exhibit 391-1b of the application, the reference for the calculations for VOM emissions from equipment is "USEPA EIIP Volume II Chapter 4, Equipment Leaks."

[47] The Emission Inventory Improvement Program (EIIP) was established in 1993 to promote the development and use of standard procedures for collecting, calculating, storing, reporting, and sharing emissions data. The EIIP was a joint project of USEPA and the State and Territorial Air Pollution Program Administrators and the Association of Local Air Pollution Control Officials (STAPPA/ALAPCO). Volume 2 of the EIIP Technical Report Series, which addresses point sources, has separate chapters addressing different categories of sources and emission units.

[48] In particular, Section 4 of the cited document states "The EPA correlation equation approach is the preferred method when actual screening values are available." Section 5.1, "Emission Calculations Using the Average Emission Factor Approach," states "The average emission factor approach is commonly used to calculate emissions when site specific screening data are unavailable." Section 5.1 goes on to state "EPA average emission factors have been developed for SOCMI process units, refineries, marketing terminals, and oil and gas production operations (EPA, November 1995). The method used by the EPA to develop emission factors for individual equipment leak emission sources is described in the *Protocol for Equipment Leak Emission Estimates* (EPA, November 1995). Tables 4.5-1 and 4.5-2 show the average emission factors for SOCMI process units and refineries, respectively."

[49] *See* Equipment Leak Calculation Summary, Exhibit 391-1b, updated October 20, 2008, application page 17-13.

[50] See Application page 8-1 and 8-2, October 21, 2008, and page 17-13, Exhibit 391-1b, October 20, 2008.

VOM emissions. (Refer to Exhibit 391-16, page 17-13, of the October 20, 2008 submittal.)

The calculations for methanol emissions reasonably account for the components in each gasification train that would be located upstream of the acid gas removal units, before the point where methanol would be introduced into the process. For this purpose, the emission calculations reflect approximately 35 percent of the flanges and connectors being located before the acid gas removal units, so that methanol would not be present. This results in potential emissions of 1.79 tons per year of methanol, which is 73 percent of the potential VOM emissions.

56. When accounting for VOM emissions from leaking components, the application does not account for certain types of components, for example, pumps in light liquid service. Although both valves and pumps in heavy liquid service were addressed, for components in light liquid service, only valves were addressed, but not pumps. The absence of certain types of components is not explained. The presence of pumps in light liquid service (even using an average SOCMI emission factor of 0.0199 kg/hr/component) would increase the VOM emissions. For this reason, the application significantly underestimates the potential emissions of VOM and methanol from leaking components at the proposed plant.

The absence of pumps in light liquid service from the emission accounting for leaking components does not mean that emissions have been underestimated. Rather, the absence of pumps in light liquid service from this accounting must be considered a commitment by Power Holdings to use "leakless design" pumps for pumps in light liquid service. Leakless pumps, such as pumps with dual mechanical seals with a barrier fluid maintained at a higher pressure than the pumped fluid, are readily feasible for new components in methanol service. Leakless pumps can be considered to provide 100 percent control of emissions.[51] In the issued permit, this practice is now explicitly required by Condition 4.9.3(c).

57. Sampling connections were another type of component that was not addressed in the accounting for VOM emissions from leaking components.

This also does not mean that emissions have been underestimated. The absence of sampling connections from the accounting for leaking components must be considered to reflect the absence of sampling connections or a commitment by Power Holdings to use "leakless sampling systems." Closed loop sampling systems should be readily feasible for any sampling systems needed at the plant. Closed loop sampling systems can be considered to provide 100 percent control of emissions.[52] Condition 4.9.3(d) of the issued permit now requires the use of closed loop sampling systems or other comparable sampling systems for any systems at the plant for routine sampling of organic streams.

58. The application does not appear to accurately identify the number of components as needed to accurately calculate VOM emissions. It appears to estimate the numbers of components because round numbers are provided, such as 150 flanges. The application should provide the basis for these estimates, such as Piping and Instrumentation Diagrams, so that this data can be verified.

---

[51] *See* Table 4.2-1, Emissions Inventory Improvement Program, Volume II – Chapter 4 - Preferred And Alternative Methods For Estimating Fugitive Emissions From Equipment Leaks November 1996.

[52] Closed Loop Sampling is considered to provide 100 percent control efficiency, as indicated in Table 4.2-1 and page 4.2.8 of *Emissions Inventory Improvement Program, Volume II – Chapter 4, Preferred and Alternative Methods for Estimating Air Emissions from Equipment Leaks,* November 1996.

The comment is correct that the application includes estimates for the number of components at the plant. This is because the engineering design of the plant has not yet been undertaken, with preparation of the detailed plans for the plant. This necessarily means that the calculations for emissions from leaking components must be based on preliminary engineering estimates for the number of different types of components. As such, this data is not amenable to verification. At the same time, this suggests that these estimates were conservative and reflect more components and associated emissions than will be present when the actual design for the plant is completed.

In this regard, irrespective of the accounting of emissions from leaking components in the application, the permit for the proposed plant includes explicit limits on the emissions from leaking components. Power Holdings must operate and maintain the plant to comply with these emission limits irrespective of the emissions calculations provided in the application.

59. The application does not provide the basis for the assumption in Exhibit 391-1b that only 5 percent of the total organic compound (TOC) emissions from leaking pressure relief valves is VOC. It is likely that emissions can be much higher, at least on a worst-case basis for calculating potential emissions.

The 5 percent factor reasonably accounts for emissions of VOM from pressure relief valves given the nature of the systems where pressure relief valves would be located, i.e., systems that are in gaseous service.[53] In the gasification block, the pressure relief valves would be located at points where only syngas is present before the Acid Gas Cleanup Units in which methanol is introduced in the acid gas cleanup process. Accordingly, the potential for emissions of VOC or VOM from leaks in these pressure relief valves is a fraction of the potential for total losses from these leaks, which would also include non-VOM material in the syngas stream, including carbon monoxide and hydrogen, as well as methane that would also be present in trace levels at this point. Pressure relief valves would also be present in the loadout systems for the gaseous argon and nitrogen that will be produced as a byproduct of the air separation units at the plant. The calculations for VOM emissions from leaking components conservatively account for the potential presence of VOM emissions in any leaks from these valves by assuming that 5 percent of the total loss would be VOM.

Pressure relief valves would not be located in the systems in the Acid Gas Removal Units that handle methanol and in the associated systems for handling methanol. These systems contribute most of the VOM emissions and methanol emissions from leaking components. For these systems, the emission calculations for leaking components assume that 100 percent of the losses are VOM.

60. While capture of CO_2 for enhanced oil recovery or sequestration is contemplated by Power Holdings, the application does not address emissions from compression of CO_2.

Any emissions of VOM or methanol from leaking compressor seals, as might accompany compression of CO_2 for enhanced oil recovery or sequestration, would be addressed with

[53] As a general matter, pressure relief valves are commonly used on systems that operate in gaseous services where gaseous materials are compressed or at elevated pressure. In such systems, overpressure events threaten the integrity of the system, requiring the use of pressure relief valves. Pressure relief valves are not typically used for systems in liquid service as the design pressures are set above the liquid pump shut-off pressure.

other emissions of methanol from leaking components. In the issued permit, Section 4.9 has been clarified to indicate that it addresses emissions from leaking components associated with the transfer of CO_2, including leaking compressor seals.

In practice, compression of the CO_2 from the plant should be accompanied by lower emissions of VOM and methanol than venting of CO_2. This is because the emissions associated with leaking compressor seals will be lower than the permitted direct emissions of methanol from the CO_2 vent, even after control with the regenerative thermal oxidizer. If this CO_2 stream were contained and underwent compression, for a single compressor (one operating compressor in each gas train), using the same calculation procedure as used for other calculations in referenced Exhibit 391-1b, except assuming no control from a leak detection and repair program and ignoring the fact that VOM or methanol would be a fraction of the stream, potential VOM emissions associated with leaks from compressor seals would be 2.2 tons per year.[54] This is less than the potential VOM emissions of the CO_2 vent of the Acid Gas Removal Unit, at which VOM emissions would otherwise occur. Accordingly, as CO_2 is contained and is not emitted from the CO_2 vent on the AGR, VOM emissions would be lower.

61. Exhibit 215 of the application, "Power Holdings Project: HAPs Summary Table," updated on October 20, 2008, has hand-corrected entries and does not appear to be accurate. In particular, while the column addressing emissions from process sources indicates methanol emissions of 9.7 tons/year, based on hand-written corrections to the table, the column addressing facility-wide methanol emissions only shows 8.13 tons/year.

The handwritten corrections to this table, which were made by Power Holdings or its consultant before this table was submitted, were incomplete. As observed by this comment, the corrections to the data for potential methanol emissions were not carried over to the facility-wide totals. Adjusting for this omission in Power Holdings' correction, the potential facility-wide emissions of HAPs are 1.57 tons/year higher than indicated in this table.

62. The VOM emissions from leaking components must be recalculated, including all types of leaking components, and all related analyses must redone for a new public comment period. While any underestimation of emissions is troubling, errors related to HAP emissions are of the greatest concern. Methanol is projected to be the individual HAP emitted in the greatest amount from the proposed plant. Power Holdings' calculations of potential methanol emissions, 9.71 tons/year, are only slightly below the major source threshold for an individual HAP, 10 tons/year. A proper calculation of potential methanol emissions would show emissions greater than 10 tons/year, with the plant being a major source of HAPs. Only small increases in emissions would result in the proposed plant being a major source of HAPs. For example, if the potential methanol emissions from leaking components were to increase by just 0.29 tons/year, from 1.79 to 2.18 tons/year, less than 20 percent, the plant would be a major source of HAPs.

This comment does not demonstrate that the proposed plant is a major source for emissions of methanol. The fact that different emissions data could theoretically make the proposed plant a major source for HAPs, as suggested by this comment, does not result in the plant

---

[54] **VOM emissions from leaking seals of the compressor can be calculated using an emission factor of 0.228 kg/hour from a compressor from Volume II, Chapter 4, Section 5, Table 4.5-1, of the *EIIP: Preferred and Alternative Methods for Estimating Air Emissions from Equipment Leaks*, November 1996. (0.228 kg/hr x 8760 hr/yr = 1997 kg/yr, or 2.2 tons/yr.)**

being a major source for HAPs.[55] The permit for the plant includes explicit limits on the emissions for HAPs from leaking components. Power Holdings must operate and maintain the plant to comply with these emission limits irrespective of the emissions calculations or other data provided in the application for emissions from leaking components.

63. The draft permit lacks BACT limits for emissions of fluorides.

The proposed plant is not subject to PSD for emissions of fluorides. This is because its potential fluoride emissions are not significant, being far less than the PSD significance level for fluorides of 3.0 tons per year. This has been explicitly addressed in Condition 4.1.6 (a) in the issued permit, which sets limits for the emissions of fluorides.[56]

64. BACT limits are missing for emissions of sulfuric acid mist.

Appropriate BACT limits have been set for emissions of sulfuric acid mist. The primary sources of sulfuric acid mist emissions at the proposed plant will be the sulfuric acid plants. Peroxide scrubbing was selected as BACT technology for these units, as stated in Condition 4.4.2(a) of the permit. A numerical BACT limit for the sulfuric acid mist emissions from these units is set in Condition 4.4.2(b).

65. BACT limits are missing for emissions of total reduced sulfur.

BACT limits for total reduced sulfur are properly absent from the permit. This is because the proposed plant is not a significant source under the PSD rules for emissions of total reduced sulfur. The plant's annual emissions of total reduced sulfur are limited to 4.76 tons per year,[57] which is less than 10 tons per year, the PSD significant emission rate for total reduced sulfur. Accordingly, the BACT requirement of the PSD rules is not applicable to the plant for emissions of total reduced sulfur.

66. The BACT analysis for the proposed plant lacks the necessary consideration of the possible use of cleaner fuels for the combustion units at the plant. In particular, in addition to natural gas, the draft permit would allow the steam superheaters and auxiliary boiler to fire syngas, i.e., synthesis gas from the gasifiers that may not have undergone complete cleanup. These units could be fired entirely with "actual" natural gas. Neither the application nor the project summary discusses the possibility of requiring only natural gas or even cleaner fuels, such as waste biomass, to be used by these units. It is not clear why cleaner fuels, either alone or in combination with the fuels that would be allowed to be used by the draft permit, are not required to be used for these units. My understanding is that natural gas is cleaner than syngas fuel and SNG, meaning natural gas would have lower emissions of one or more NSR pollutants. Also, SNG is cleaner than syngas fuel. However, the emissions that would accompany the use of cleaner fuels in these units has not been documented. To properly evaluate BACT for the superheaters and auxiliary boiler, emission data must be provided for the potential use of cleaner fuels. The Illinois EPA must, at a minimum, identify the relative emissions from use of syngas fuel, SNG, and natural gas in the record.

---

[55] One could also speculate that the plant's potential emissions of methanol have been overstated in the application. The bulk of the methanol emissions projected from the plant (7.1 out of 9.71 tons/year) is from methanol carryover to the CO_2 vent. The data for methanol emissions from the CO_2 vent may be overstated as they reflect conservative, preliminary projections for the amount of methanol carryover from the Acid Gas Recovery Unit. In practice, given the cost of methanol, the process should be expected to be designed for more efficient recovery of methanol, with less carryover.

[56] Condition 4.1.6 (a) in the issued permit limits fluoride emissions to 0.011 pounds per hour and 0.1 tons per year total.

[57] Condition 4.1.6 of the permit limits emissions of total reduced sulfur from the gasification block. Condition 4.4.6(a) limits emissions from the sulfuric acid plants.

In fact, the auxiliary boiler would only be allowed to use natural gas. (See Condition 4.2.5(a)(ii) of the draft permit.) This is inherent in the operation of the auxiliary boiler. It must be designed so that it can operate when the rest of the plant is out of service and is not producing any fuel quality material. This necessitates use of a commercial fuel, such as natural gas. Natural gas is considered a very clean fuel. It is cleaner than both waste biomass and "primary" biomass, which are solid fuel. As such, combustion of biomass emits more particulate matter than natural gas, due to the ash material present in biomass. As biomass is a solid fuel, the management of the combustion process for biomass is more difficult than that for natural gas and accompanying emissions of carbon monoxide and volatile organic material, which are products of incomplete combustion, should be expected to be higher. Emissions of nitrogen oxides from combustion of natural gas are also higher.[58] Finally, the sulfur content of biomass is typically higher than that of natural gas, which is processed to remove sulfur compounds, so that emissions of sulfur dioxide from combustion of biomass are higher than those of natural gas. As waste biomass were used, it must also be contemplated that variability in the composition of this material would make consistent operation more difficult or necessitate less preferable operational conditions, therefore acting to further increase emissions from use of biomass fuel.

In response to this comment, the issued permit restricts the superheaters to use of only natural gas, rather than syngas or natural gas as would have been provided by the draft permit. (See Condition 4.2.5(a) of the issued permit.) Note that use of either "natural" natural gas or product synthetic natural gas (SNG) from the plant is allowed. This is because the properties of SNG as related to emissions, i.e., the heat content, sulfur content and ash content of SNG, are and must be essentially identical to those of natural gas.[59]

The superheaters have been restricted to use of only natural gas because the application does not explicitly address the difference in the composition and properties of natural gas and syngas and the resulting difference in emissions of SO_2 and other pollutants. While there should not be a significant difference in the composition of syngas and natural gas, given the effectiveness of the Acid Gas Cleanup System, in the absence of an explicit evaluation, it must be assumed that natural gas contains less sulfur and ash than syngas, which does not undergo processing in a methanation unit. In addition, the application does not demonstrate that the use of syngas in the superheaters would be accompanied by lower overall emissions from the proposed plant.[60]

67. The BACT analysis lacks the necessary consideration of the use of cleaner feedstocks by the plant, such as waste biomass. Gasification of biomass would also be accompanied by lower emissions of SO_2, sulfuric acid mist, HAPs, and other pollutants. Gasification of biomass would also be preferable with respect to global warming. The US Department of Energy's website notes that in 2002, there were almost 10,000 MW of installed biomass capacity in the United States, the

---

[58] Management of the combustion process for biomass, especially waste biomass, would also be more difficult as there is greater variability in the composition of the biomass and its heat and moisture content than is present with natural gas.
[59] The composition of SNG will be "purer" than natural gas, having lower levels of ethane, propane and other organic constituents that are present in trace amounts in natural "natural gas." This is because SNG is produced by a chemical process rather being a naturally occurring material, so that more of the fuel component of SNG will be methane.
[60] Use of syngas as fuel in the superheaters could result in lower overall emissions if it enabled the productive use of syngas during an upset, thereby eliminating the flaring of such syngas while at the same time using natural gas to maintain the operation of the superheaters.

largest source of non-hydro renewable electricity.[61] The sources of biomass included forest products and agricultural residues and were fired using gasification, direct firing, or co-firing. A proper BACT analysis must consider use of biomass feedstock, in place of some or all of the coal feedstock, for the gasification process as opposed to coal alone.

The use of biomass as the feedstock for the proposed plant can be readily considered and rejected. The use of biomass is precluded by the scale of the proposed plant, which is inconsistent with the quantity and nature of biomass that would potentially be available for the plant.[62] The nature of the proposed plant, which would produce a commodity for sale, SNG, on a commercial basis, is inconsistent with use of biomass as a feedstock. As a general matter, the composition and properties of biomass are significantly different than those of coal,[63] which means that biomass is not a suitable feedstock for gasification systems and technology designed to use coal. Gasification technology for conversion of biomass into commercial SNG, especially at the scale of the proposed plant, is still in the research and development stage. Finally, given the level of emissions control required of the proposed plant, the use of biomass feedstock should not be expected to be accompanied by lower levels of emissions of regulated pollutants.[64]

To the extent that waste or low-quality biomass is currently being used, it is to produce a fuel that is then burned for its heat energy, not as a chemical feedstock.[65] The use of biomass as a fuel or to produce to produce fuel that is immediately burned at the source does not demonstrate that biomass is a suitable feedstock for production of SNG. A key aspect of gasification for production of SNG and other chemical products is consistently producing syngas with the correct ratio of hydrogen and carbon monoxide. This is

[61] See http://www1.eere.energy.gov/biomass/index.html; see also U.S. Forest Service, Research Note NRS-3, Illinois' Forest Resources, 2006; U.S. Department of Energy - Energy Efficiency and Renewable Energy Alternative Fuels and Advanced Vehicles Data Center: Illinois State Assessment for Biomass Resources, available at http://www.afdc.energy.gov/afdc/sabre/sabre.php?state=illinois.

[62] Based on the assessment of biomass resources by the US Department of Energy, the proposed plant would challenge the potential biomass resources of the entire State of Illinois, competing with corn and cellulosic ethanol production for these resources. By contrast, as discussed, given the size of the proposed plant, there is not sufficient potential biomass within 50 miles of the proposed plant, generally a practical restriction for transportation of biomass fuels, to support the proposed plant.

As described by USDOE's Office of Energy Efficiency and Renewable Energy, in its State Assessment for Biomass Resources: Illinois Potential for Biofuel Production (available at http://www.afdc.energy.gov/afdc/sabre/sabre.php), there are very limited supplies of forest and primary mill residues in Illinois, as would be used by the Bay Front project. Other than in the Chicago Area, where urban wood residues are available, biomass is potentially present in Illinois as crops and crop residues, which are lower quality biomass than wood. Further, the counties around the proposed plant have among the lowest potential for production of such material in Illinois.

[63] As compared to coal, more of the carbon in biomass is in a volatile form rather than being present as fixed carbon. Biomass is also not a friable material and cannot be pulverized like coal. This means that significantly different gasification processes must be used for gasification of biomass, as compared to coal, to address the physical form of the feedstock and relative role of various chemical reactions in the gasification vessel.

[64] The performance of the gas cleanup systems for coal gasification plants reflect residual levels of contaminants in the cleaned syngas, based on the capabilities of the required gas cleanup systems, rather than removal of percentages of the contaminants originally present in the raw syngas. As such, the performance of the syngas cleanup systems is independent of the level of the contaminant in the feedstock. In other words, "cleaner fuels," which contain less sulfur or ash, do not translate into lower SO_2 or PM emissions. For pollutants for which emissions are determined by the combustion process, emissions are also unchanged as those emissions are determined by the properties of the fuel, which are unchanged as natural gas or SNG would still be the fuel.

[65] At the present time, particular types of "high-quality" biomass are used for production of certain chemicals, e.g., ethanol from corn and biodiesel from vegetable oil. Not only do these processes generally involve "high quality" forms of biomass, but they involve specific conversion processes and equipment that have been developed for the processing of particular feedstocks. This does not show that biomass is generally suitable as a feedstock for chemical production processes. It instead shows the specialized nature of chemical production processes.

important for the efficiency of the subsequent chemical reaction(s) to convert the syngas to the desired product. These considerations with chemical production are greatly reduced when biomass is used as a feedstock for production of fuel syngas, in which either hydrogen or carbon monoxide will serve as fuel. Combustion is much more tolerant of variation in fuel or feedstock composition that chemical production. This is because the fuel is destroyed during combustion, with the desired output being the thermal energy in the fuel. However, the proposed plant would be producing syngas as an intermediate for conversion to SNG, for commercial sale and use at other sources. As related to use of low-quality biomass as a chemical feedstock, research is ongoing to facilitate use of biomass as a feedstock for chemical and fuels production.[66] Biomass gasification is not yet technically feasible at the scale of the proposed plant. [67]

These factors, which preclude use of biomass as the feedstock for the proposed plant, also preclude use of a blend of coal and biomass as the feedstock for the plant. Moreover, as farming to produce low quality biomass feedstocks, of the type that would potentially be used at the proposed plant, is in its infancy, biomass feedstocks cannot yet generally be considered commercial fuels. The continuing availability of such feedstocks and the future cost of such feedstocks cannot be determined or predicted in a way that would allow them to be considered available feedstocks. In this regard, key factors are the nature of government programs that accelerate the development of commercial biomass feedstocks and the extent to which regulations are adopted and programs implemented that increase competition for those resources. This situation with the proposed plant is different from projects in which the developers propose to utilize or develop certain biomass resources. In those cases, the developers are voluntarily accepting the uncertainty in the future availability and cost of material from the selected resource. Finally, use of a blended feedstock, even if feasible, would act to negatively affect the operation of the plant. The increase in the complexity of the gasification process, which would be inherent in using a blend of coal and biomass, would be contrary to consistent and reliable operation, such that an increase in process upsets and flaring should be contemplated.

68. A recent precedent for use of biomass by the proposed plant is a project proposed by Xcel Energy. Xcel is proposing to build a biomass gasification unit that would gasify about 250,000 tons of biomass annually at its existing Bay Front Generating Station in Ashland, Wisconsin. Publicly-available information for this project shows that use of biomass is cost-effective. At the Bay Front Station, Xcel Energy is currently paying between $25.00 and $29.00 per ton of wood waste, which is equivalent to between $3.85 to $5.27 per mmBtu.[68] According to Xcel Energy:

> Biomass gasification is a technology that has been studied and developed over the past half century and continues to have global activity due to growing interest in clean, renewable energy. Hundreds of biomass gasifies are in operation around the world. The majority of

[66] The United States Energy Information Agency (EIA) states "The U.S. economy uses biomass-based materials as a source of energy in many ways. Wood and agricultural residues are burned as a fuel for cogeneration of steam and electricity in the industrial sector. Biomass is used for power generation in the electricity sector and for space heating in residential and commercial buildings. Biomass can be converted to a liquid form for use as a transportation fuel, and research is being conducted on the production of fuels and chemicals from biomass." *See* Energy Information Agency, *Biomass for Electricity Generation*, EIA-Biomass Gasification http://www.eia.doe.gov/oiaf/analysispaper/biomass.
[67] For example, *see* United States Department of Energy, Publication on Biomass Gasification, which indicates that "key challenges to hydrogen production via biomass gasification involve reducing costs associated with capital equipment and biomass feedstocks." http://www1.eere.energy.gov/hydrogenandfuelcells/production/biomass_gasification.html
See Energy Information Agency, Biomass for Electricity Generation: EIA-Biomass Gasification, circa 2002
[68] See Assessment of Biomass Resources for Energy Generation at Xcel Energy's Bay Front Generating Station at Ashland, Wisconsin, Energy Center of Wisconsin, 2007.

> these are in Asia and Europe and are small-scale plants providing less than 5 MWe of heat or electricity to farms and small industries. To date, biomass gasification installations for production of electricity in the United States have predominantly been small-scale plants; however, some larger-scale plants have been installed in recent years. The pulp and paper and food processing industries have employed biomass gasification to a much greater extent in the United States to provide steam.[69]

The circumstances of the Bay Front project are very different from those of the proposed plant. At a very basic level, the Bay Front project would be developed to utilize or take further advantage of the available and relatively inexpensive biomass resource in the vicinity of the project to generate electricity. Indeed, the Bay Front Station has been characterized as a model for use of diverse fuels, as it uses waste wood, railroad ties, and discarded tires in addition to coal, petroleum coke, and natural gas. As such, the Bay Front project does not show that biomass is either an available or feasible feedstock for the proposed plant, which would be developed to produce SNG from Illinois' reserves of coal. If anything, the proposed Bay Front project highlights the differences between projects where biomass can be used and those where it cannot.

By way for further explanation, the Bay Front project would involve installation of a gasifier to produce syngas for use as fuel in an existing boiler at this power plant for generation of 20 MW of electricity in its existing steam turbines.[70] That is, the Bay Front would entail immediately burn the syngas that is generated to produce heat and steam, rather than using the syngas as a chemical intermediate. As compared to the proposed plant, the Bay Front project is a much smaller project, less than 1/70th the size of the proposed plant.[71] The Bay Front project would be located in Northern Wisconsin, in an area whose existing biomass resources are sufficient for the project's needs, given its planned size. Indeed, the Bay Front Station is already utilizing biomass as the primary fuel in two of its three boilers and the proposed project would continue the use of this established resource, only now with gasification. By contrast, as discussed, given the size of the proposed plant, there is not sufficient potential biomass within a practical distance from the proposed plant to support its operation. Moreover, the size of the proposed plant is dictated, as a consequence of the economy of scale, by the size of a facility needed to economically produce SNG. Lastly, the Bay Front project would likely use a fluidized bed gasification process,[72] rather than the more refined quench gasification process that would be used at the proposed plant. Fluidized bed gasification is a type of gasification technology that is suitable for conversion of a biomass feedstock into a syngas. As such, the Bay Front project would be developed with a gasification technology that is suitable for the design feedstock. The project is not being developed to use a blend of biomass and coal in the

---

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

[70] **A companion document for the Bay Front project, Assessment of Biomass Resources for Energy Generation at Xcel Energy's Bay Front Generating Station at Ashland, Wisconsin. by the Energy Center of Wisconsin, April 2007,[70] finds that wood residues from sources within about a 50 mile radius of the Bay Front plant, including harvest residues in Wisconsin, commercial loggers, primary and secondary mill residues and forest thinnings, may be sufficient to provide the feedstock for small gasification facilities**.

[71] **The nominal daily input of feedstock for the proposed plant would be about 350,000 million Btu. By contrast, the estimated nominal daily heat input of the Bay Front project would only be about 4,800 million Btu, based on its electrical output of 20 MW and a nominal heat rate of 10,000 Btu per KW-Hr.**

[72] **The application for Bay Front, page 6, indicates "For this Project, NSPW focused on fluidized bed gasification technology…Other gasification configurations, including fixed bed, will remain under consideration as Project planning and procurement proceeds."**

gasifier. If coal must be used to maintain the output of the station, it can continue be a supplemental fuel in the other two boilers at the Bay Front Station.

69. Another example of the gasification of biomass are the proposed projects announced by Progress Energy Florida, which currently has two contracts with Biomass Gas & Electric LLC (BG&E) to purchase electricity from waste-wood biomass gasification plants to be developed in Florida. These plants would be located in northern or central Florida and use waste wood products—such as yard trimmings, tree bark, and wood knots from paper mills. One plant would be designed to produce about 45 MW of electricity and the second about 75 MW.

The planned projects cited by this comment do not show that biomass can be used as feedstock for the proposed plant.[73] The cited projects would generate electricity, not produce SNG. From their size and general location, it is apparent that these projects are specifically targeting existing supplies of waste wood biomass that would be available in areas served by Progress Electricity. As such, these projects also confirm that biomass is not a suitable feedstock for the proposed plant, given its product, size, and location.

70. It is unclear from the permit if the coal used by the plant would be washed. The application states that it is Power Holdings' intent to receive washed coal. The permit should limit the sulfur content of the coal supply for the plant if the Illinois EPA's analysis for SO_2 emissions presumed the lower sulfur content of washed coal.

The Illinois EPA's analysis for SO_2 emissions did not rely on a reduction in emissions due to use of washed coal by the plant. This is because the performance of the gas cleanup system for sulfur compounds in the raw syngas reflects residual levels of sulfur in the cleaned syngas, based on the capabilities and performance of the required cleanup system, rather than removal of a percentage of the sulfur originally present in the raw syngas. Accordingly, sulfur content of the coal need not be limited because the limits and other requirements set by the permit for SO_2 already fully serve to minimize emissions of SO_2

Incidentally, Power Holdings indicates that the coal for the plant will be washed because the planned GE gasifiers are designed to process feedstock with less ash than raw Illinois coal. Washed coal would be used for the reduction it provides in the ash content of the coal supply. For particulate matter, as with SO_2, the performance of the gas cleanup system reflects residual levels of ash or particulate matter in the cleaned syngas, based on the capabilities and performance of the cleanup system, rather than removal of a percentage of the ash originally present in the coal supply or the raw syngas.

[73] A more relevant "precedent" for use of biomass at a coal gasification facility making a chemical product for sale, rather than directly producing electricity, is the proposed Ohio River Clean Fuels facility. This is a large coal gasification facility proposed by Baard Energy to produce synthetic diesel and jet fuel that would initially, in Phase I, be about the same size as the proposed plant in terms of its coal usage. Baard has indicated that this proposed facility would be designed to use about 10 percent biomass as feedstock, on an energy equivalent basis. However, the proposed Ohio River facility also does not demonstrate that the permit for the proposed plant should mandate that the plant's feedstock be supplemented with biomass. First, Baard has voluntarily proposed use of biomass of feedstock as part of its plans. Second, Baard has not committed nor is it required by its construction permit to use any biomass as a feedstock. Third, the viability and feasibility of the proposed Ohio River facility, with or without supplemental use of biomass, is not demonstrated. The development of the proposed facility has been challenged by environmental organizations and the financing for the construction of the facility has not been completed. Lastly, the proposed Ohio River facility would make synthetic liquid fuels using the FischerTropsch process, which is significantly different from making SNG from syngas using Methanation. As planned by Baard, the proposed facility would have a separate Hydrogen Unit to support an Upgrading Unit that would "adjust" the raw liquid fuel product. In addition, the off-specification "heavy ends" from the FischerTropsch Unit, which are not suitable for use as commercial fuel, would be used on-site for power production. This means the proposed facility would be more amenable to variation in the feedstock fed to the gasifiers.

71. The BACT analysis makes numerous references to reliance on vendor data, in addition to USEPA's *RACT/BACT/LAER Clearinghouse* (RBLC). However, the application only contains RBLC information. No vendor data could be found. In order to provide a transparent basis for the BACT analysis, all vendor consultations and documentation received from vendors should be included. This includes all vendor cost data.

Notwithstanding the claim made in this comment, the discussions of BACT in the application and in the project summary do not make numerous references to reliance on "vendor data." The discussions of BACT relied on generally available information about the nature of different types of control devices and control technology.[74,] Accordingly, "vendor data" did not have to be provided because it was not part of the application a factor in the BACT analysis.[75]

Moreover, this permit is a construction permit, which Power Holdings must obtain before commencing construction on the proposed plant. Given the magnitude and nature of the proposed project, it is unrealistic to expect that vendor data of the type apparently sought by this comment would be available for inclusion in the application and submittal by Power Holdings. The permit specifies the emission rates and other requirements that must be met by the various emission units at the plant. It would be premature for Power Holdings to enter into detailed discussions with potential equipment suppliers until the permit is issued setting those requirements or "specifications" for the plant. Power Holdings and its equipment procurement construction contractor should only be expected to begin such discussions after the requirements that must be met by the plant are established by the issued permit and the actual bid and contract processes are initiated. Preliminary discussions between Power Holdings and potential vendors that have occurred are not binding on either Power Holdings or the vendors. As such, information concerning those discussions could not be considered reliable even if Power Holdings elected to provide such information.[76] In this regard, the role of vendor data in the permitting of the proposed plant is very different than that for a project in which vendor data is being used to demonstrate why a particular emission rate cannot be met.[77]

---

[74] **The cost data used by Power Holdings in its BACT Demonstration was prepared using cost estimating methods developed by USEPA's Office of Air Quality Planning and Standards.**

[75] **The Illinois EPA also did not rely in its BACT determination on specific data from particular vendors of equipment to eliminate otherwise feasible control technologies for the proposed plant. As the Selexol and Rectisol processes for cleanup of the raw syngas were discussed in the Project Summary, the Illinois EPA was referring to generally available information about these two processes, as available in the general literature. (For example, *see* USEPA, *Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies,"* (EPA-430/R-06-006, July 2006). The limits set BACT for the gasification block also reflect use of the Rectisol process, which is the more effective process for removal of sulfur compounds.**

[76] **The USEPA addressed a similar issue in its in Order in Trimble County. With respect to inclusion of manufacturer's data in a construction permit application, USEPA observed that "In general, companies may not have contracted for construction at the time the permit application is pending because many companies are reluctant to enter into binding contracts without a final preconstruction permit. Although the application and the permit specify the design of the affected units, there are often many manufacturers of the control technologies and other components such that inclusion of all operation and maintenance information in the permit record may not be practical." Order, page 10.**

[77] **For example, with a simple cycle combustion turbine, a NOx emission rate maybe very dependent on the design of the turbine Vendor Technology developed to individual Turbine model and size of turbine. So, while the Clearing House Data Base might show a very much lower NOx emission rate being proposed for a hypothetical project; that particular project might have need for only a very different machine where only higher emission rates are available. In that hypothetical situation, where the actual permit limit is dependant on Vendor Data; then inclusion of that specific Vendor Data maybe appropriate.**

72. In Section 5.1 of the application, Power Holdings improperly dismisses the need for NOx BACT for the thermal oxidizers, which are to be used as the control devices for CO and VOC. The choice to use the regenerative thermal oxidizers themselves is not defended in the application. CO and VOC reductions can be accomplished by other means, such as catalytic oxidizers, that can also provide much lower NO_x emissions.

This deficiency in the initial application for the proposed plant, submitted on October 17, 2007, referred to in this comment, was corrected in a subsequent submittal that addressed NOx BACT. (Refer to pages 16 through 20 of the December 17, 2008 submittal.) This supplemental material addresses NOx BACT for these control devices, supporting the selection of regenerative thermal oxidation technology. NOx BACT for these devices was also discussed on page 9 of the Project Summary.

As a general matter, catalytic oxidizers used for control of CO operate at temperatures in the range 500 to 700 ºF, with efficient combustion at such temperatures facilitated by the presence of a catalyst. As such, catalytic oxidizers have application for control of hot or warm exhaust streams in which little or no supplemental fuel must be burned to raise the temperature of the stream to the operating temperature of the catalyst. However, the expected temperature of the exhaust from the Syngas Cleanup Units, after the syngas has undergone cleanup with the Rectisol process, is in the range of 32 to 70 ºF, which is well below the operational temperature of a catalytic oxidizer. Accordingly, use of a Catalytic Oxidation Technology would require more supplemental fuel to heat the exhaust gas than Regenerative Thermal Oxidation Technology. This is because regenerative thermal oxidizers (RTO) capture and reuse most of the thermal energy (heat) that would otherwise be vented to atmosphere to maintain a high thermal efficiency of the oxidizer. As this "regeneration" substantially lowers the amount of supplemental fuel needed for operation of the oxidizers, the regenerative design of the oxidizers also acts to reduce NOx emissions as compared to use of a catalytic oxidizer.[78] This regeneration is made practical by the high temperature at which the combustion chamber operates, which also ensures the high destruction efficiency for the emissions of CO and VOM that are being controlled by the oxidizers. In contrast, catalytic oxidizers operate in a range at which heat recovery is impractical. As applied to the exhaust streams from the Acid Gas Removal Systems, more supplemental fuel would be consumed, accompanied by greater emissions of NOx.

73. For the gas-fired auxiliary boiler, the application asserts that over-fire air (OFA) is not a feasible alternative for controlling NO_x emissions because of space limitations. There is no basis in the record for this assertion. Nor is this conclusion based on valid reasoning. For example, the application does not include any vendor data or other documentation to show that installing OFA on this type of boiler is technically infeasible. No engineering drawings have been provided, along with appropriate dimensions, locations of the likely OFA, nor any of the other information necessary to make a determination that OFA is not feasible. Without such documentation or support, simply asserting that space limitations preclude the consideration of OFA for auxiliary boilers, is inappropriate and fails to comply with the BACT determination process.

Overfire Air (OFA)[79] was appropriately rejected as a possible NOx control technique for the auxiliary boiler. This is because the auxiliary boiler would be fired with natural gas,

---

[78] With regeneration the temperature of the exhaust of the oxidizers is expected to be less than 300 F, substantially lower than the 500 to 700 °F that would be present with catalytic oxidation.

[79] Overfire Air (OFA) is a combustion control technique for NO_x in which some of the combustion air is diverted from the burners themselves to the space or area "over" or above the burners. In larger boilers, such as utility pulverized coal-

i.e., a gaseous fuel. OFA is NOx control technique that can be used on certain designs of coal or solid fuel-fired boilers. It is not a feasible technique for gas-fired boilers since gas burns "more quickly" than a solid fuel, since it is already a gas. Unlike a solid fuel, a gaseous fuel does not have to be vaporized by and during combustion. This generally means that the combustion process for a gaseous fuel proceeds more rapidly and must be managed by the design of the burner itself. Separating the supply of combustion air, as would occur with OFA, would pose concerns for safety as the hot, partially combusted natural gas could potentially explode when the rates of primary, secondary and OFA combustion air were out of balance. Accordingly, OFA is not used on gas-fired boilers, which use other control techniques for NOx emissions.

While these circumstances may not have been addressed as clearly one might wish in the BACT analysis prepared by Power Holdings, they were addressed. In particular, the analysis recognizes OFA as a NOx control technique for solid-fuel fired boilers that is not, however, transferable or feasible for gas-fired boilers. [80] The basis upon which OFA was rejected by the Illinois EPA reflects general knowledge about combustion systems and does not rely on project-specific vendor data.

Incidentally, this comment does not object to the NOx BACT limit for the Auxiliary Boiler of 0.035 lbs/mmBtu, which is lower than the lowest limit currently shown in the RBLC, i.e., 0.04 lbs/mm Btu for the Columbia Energy Center.

74. The proposed plant would create SNG from approximately 5,000,000 tons of coal feedstock annually. This would be a huge chemical plant. Nevertheless, the application indicates that the project's impacts on air quality will not be significant.[119] *See* Section 5.1 of the application.

The emissions of the proposed plant would be very well controlled. As a result, as shown by the modeling and assessment conducted for the proposed plant, the plant will not have significant impacts on ambient air quality.

75. The public review and comment process has been made overly difficult because of the changes to the project and the lack of a single, coherent "application." The documents provided for my review, and purporting to be part of the "application" include some information for an SNG plant proposed to be built at a site near Mt. Vernon, Illinois. The air impact analysis for that version of the project was prepared by Huff & Huff, Inc. and submitted in November 2005. Another revision, for the current site in Blissville Township, west of Waltonville, was prepared by Mostardi Platt Environmental and submitted in October 2007. Yet another revision included a completely different coal delivery, receiving, and storage system. This more recent revision is dated November 2008, but includes only piecemeal revisions, and was prepared by yet another consultant, ENSR Corporation.

---

fired boilers,[79] there is space above the coal burners to do this because the furnace must be designed with sufficient volume, i.e., space, above the burners to provide the residence time for the solid particles of coal to be completely combusted. This space, which is inherent in the design of such boilers, can then also be used for OFA. The introduction of combustion air in stages, with OFA, acts to "stretch out" the combustion process, lowering the peak flame temperatures in the combustion zone, so less thermal[79] NO_x is created.

[80] "OFA is a mature technology most often utilized concurrently with the application of LNB. OFA compliments the stoichiometric to sub-stoichiometric operation of LNB by providing the air required to complete fuel combustion and limit the formation of CO and VOC. OFA is expected to be furnished with a new solid-fuel boiler regardless of other post-combustion NO, emission reduction technologies employed. However, for the gas-fired boiler with LNB (and flue gas recirculation discussed below), OFA is not a suitable technology. For these reasons, OFA is considered technically infeasible and will not be considered in combination with other NO, reduction technologies for the auxiliary boiler." Page 1-51 of Power Holdings' October 17, 2007 submittal.

An applicant for a construction permit is not prohibited from changing his plans for a proposed project. Moreover, a permit applicant is also obligated to appropriately update its application as necessary to address changes in the plans for the project. Given the duration of application process, an applicant may also elect to change consultants that it uses. While this may make it difficult for members of the public to review a proposed project, it does mean that their review of the application was overly difficult. The difficulty of review is simply a consequence of the history and evolution of the project.[81]

The October 2007 material, which was prepared by Mostardi-Platt, clearly states that it "... replaces the previous application filed by Power Holdings in June 2006. Since that filing, additional engineering studies have been performed and refinements made to the design for the plant that affect emissions. This application reflects the current plant design and site location."[82] The current site location is clearly identified in the October 2007 application submittal as west of Waltonville in Blissville Township.

76. The latest project revision, and accompanying air quality analysis, required review and interpretation of the earlier material submitted for the proposed project. This is because the November 2008 submittal only covered the changes in the design of the coal handling and storage system for the plant. Thus the difference between the air quality analyses that are part of this submittal, which was prepared by ENSR, and previous air quality analyses, which was prepared by Mostardi Platt, are unclear. It is not clear which analysis constitutes the "application," and which are no longer part of the "application."

The November 2008 application submittal prepared by ENSR addressing changes in the plans for the coal handling and storage facilities for the plant[83] did not cover "only" these changes. Of necessity, as these changes added additional particulate matter emission units to the plant, it also was necessary for further air quality analysis to be submitted for particulate impacts to address the entire plant, including both "old" emission units, which had been addressed in earlier submittals, and the "new emission units," which were only then being addressed.

As has already been discussed, Power Holdings' plans for the proposed plant have evolved and changed over time. As is also apparent, the most recent information submitted about particular aspect(s) of the proposed plant governs, supplementing or replacing previous information on those aspects of the plant. A person reviewing the application for the proposed plant should keep this principle in mind. Accordingly, after conducting an initial review of the application to determine the general nature of the proposed plant, a person may then want to consider conducting his or her detailed review of the application beginning with the most recent submittal and working backwards in time.

---

[81] Another contributing factor to the confusion of this commenter is that he requested information for the project under the Freedom of Information Act (FOIA). In response to that request, the commenter was provided a copy of the application files for both the Mt. Vernon and Blissville Township project locations.

[82] Page 1-2 of October 17, 2007 application material.

[83] As related to handling and storage of coal feedstock for the proposed plant, the November 2008 submittal specifically addressed a change in the plans for this aspect of the proposed plant. The revised plans for the plant would now include facilities to receive coal by rail and store coal at the plant. The previous plans for the plant was based on receiving slurried coal by pipeline, essentially on an "as needed" basis, without significant storage capacity at the plant.

77. Mostardi Platt, one of the consultants used by Power Holdings, sued Power Holdings for "not paying their bill,"[84] As a result, material that is purportedly part of the "application" has been withheld from the public or has been redacted preventing the public from having complete application to review for purposes of providing public comments. This, alone, prohibits Illinois EPA from issuing the permit. 40 CFR 52.21(q) and 124.10(d)(iv) and (vi) (providing that the permit application and entire record must be available for public inspection). In addition, it appears that Power Holdings is not authorized to continue using Mostardi Platt's work product, which constitutes much of the application for the proposed plant.

The lawsuit referred to in this comment has not resulted in any material in the application submitted by Power Holdings not being available for inspection by the public. Power Holdings has not claimed any information in the material that it has submitted to be a trade secret. Accordingly, the complete application submitted by Power Holdings has been available for inspection by the public.

The documents that were redacted and were not provided in their entirety to certain individuals involved material was made available pursuant to a request under the Freedom of Information Act (FOIA). This FOIA request extended to e-mail generated by Illinois EPA staff. The documents that had portions redacted were "internal e-mails" exchanged between technical and legal staff of the Illinois EPA staff, not documents submitted by Power Holdings. Portions of these e-mails were not provided pursuant to the FOIA request as they involved preliminary opinions and communications between Illinois EPA staff with respect to the lawsuit filed by Mostardi Platt. As such, the redacted material should not be considered part of the administrative record for this application.

As a final matter, the existence of a contractual dispute between Power Holdings and Mostardi Platt, as reflected by the lawsuit filed by Mostardi Platt, does not act to place in doubt the portion of the application that was prepared by Mostardi Platt. The lawsuit concerns the adequacy of payments made to Mostardi Platt for services it provided in preparing application material, not the technical accuracy of that material.

78. Because the initial modeling for the proposed plant showed that its impacts would be below significant impact levels (SILs) for various pollutants and averaging times, further analysis of the proposed plant's air impacts, including impacts on increments, was not conducted. However, SILs are not a legal basis to exempt an applicant from performing detailed air quality analyses to address compliance with air quality standards, especially increments. (Neither the Illinois EPA nor Power Holdings identified a legal basis to rely on SILs.) The Illinois EPA improperly allowed reliance on SILs in the air quality analyses required under the PSD rules to avoid detailed air quality analyses. Moreover, to the extent that any regulations use SILs, they apply only to NAAQS. For example, 40 CFR 51.165(b)(2) a table setting forth NAAQS SILs. However, these SILs apply only to NAAQS, and not for the PSD increments.

The use of SILs when conducting air quality analyses and modeling under the PSD Program is both legally appropriate and established practice. This comment does not show that this practice is improper. In particular, the cited rules, 40 CFR 51.165 provides the USEPA's formal guidance for state permitting programs to protect nonattainment areas, not guidance for state PSD Programs, which are addressed in 40 CR 51.166. It is understandable that 40 CFR 51.165 does not address applicability of SILs to PSD increments since increments do not nor could they meaningfully apply in nonattainment

[84] Email from Joseph Macak, Mostardi Platt Environmental, to Robert Smet, Illinois EPA, March 24, 2008.

areas as air quality in such areas exceeds the NAAQS.[85] The use of SILs when conducting air quality analyses under the PSD program is generally confirmed by USEPA's, New Source Review Workshop Manual, (Draft), October 1990 (NSR Manual).[86] It is **further confirmed by proposed rulemaking by USEPA that would include establishment of SILs specifically for $PM_{2.5}$. In the preamble to these proposed rules, when explaining SILs, USEPA clearly states that SILs can be relied for air quality analyses under the PSD program, including analyses for both NAAQS and PSD Increments.[87]**

79. While the SILs should be considered unlawful for any purpose, the distinction in the regulations by providing SILs for NAAQS but not increments makes some sense. Increments are much lower values than NAAQS and are not protected with ambient air monitoring networks and other SIP-planning requirements in the same way that NAAQS should be monitored and protected. NAAQS violations can be detected and corrected through the Clean Air Act, whereas without full modeling analysis, increment violations are never detected nor prevented.

As already discussed its proposed rulemaking that would include establishment of SILs for $PM_{2.5}$, USEPA confirms that SILs are applicable for both NAAQS analysis and Increment analysis under the PSD program. In addition, the distinction between NAAQS and Increments suggested by this comment is without basis. While there may be less concern about PSD Increments, perhaps because they are not health-based standards and compliance is verified during PSD permitting, PSD Increments act as air quality standards, subject to the same legal protections as NAAQS.

80. The use of SILs to avoid increment analysis cannot be justified by the NSR Manual. The NSR Manual, while valuable for some purposes, is not a final agency action and is not law.[88] Additionally, because it has not been updated for almost 20 years, the NSR Manual is also outdated in some ways.[89] Further, the NSR Manual merely copies the NAAQS SILs at the time it was prepared. They were not established based on any analysis of increments, or the need to protect increments. Nor do they account for the fact that increments are much smaller values that

---

[85] Moreover, as use of SILs is recognized as an appropriate practice under NA NSR for areas that are designated nonattainment, this also indirectly confirms that they are appropriate practice under the PSD program, which governs permitting in attainment areas. This is because practices to address air quality in nonattainment areas should be more rigorous as such areas are nonattainment.

[86] USEPA, New Source Review Workshop Manual (Draft), October 1990, page C. 28 (as available at http://www.epa.gov/region7/programs/artd/air/nsr/nsrmemos/1990wman.pdf).

[87] Proposed Rules: Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers (PM2.5)—Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC) , 72 FR 54112, *See* page 54138, "Significant Impact Levels or SILs are numeric values derived by EPA that may be used to evaluate the impact a proposed major source or modification may have on the NAAQS or PSD increment."

[88] While the NSR Manual is helpful when it explains how to implement NSR programs, but it does not, cannot, and is not intended to supersede statutory and regulatory requirements. As the preface to the Manual notes "This document was developed for use in conjunction with new source review workshops and training, and to guide permitting officials in the implementation of the new source review (NSR) program. It is not intended to be an official statement of policy and standards and does not establish binding regulatory requirements; such requirements are contained in the regulations and approved state implementation plans. Rather, the manual is designed to (1) describe in general terms and examples the requirements of the new source regulations and pre-existing policy; and (2) provide suggested methods of meeting these requirements, which are illustrated by examples. Should there be any apparent inconsistency between this manual and the regulations (including any policy decisions made pursuant to those regulations), such regulations and policy shall govern. This document can be used to assist those people who may be unfamiliar with the NSR program (and its implementation) to gain a working understanding of the program."

[89] For example, the NSR Manual discusses significant impact levels for PM_{10}, even though there were no PM_{10} PSD increments in existence at the time—only total suspended particulates (TSP) increments. Manual, page. C.7.Since PSD increments for PM_{10} were not established until 1993, the NSR Manual cannot reflect any conclusions as to the appropriate SILs for PM_{10} increments.

the respective NAAQS and a SIL may represent an insignificant percentage of NAAQS, while representing a larger percentage of the increment.

The effect of the unofficial and unsanctioned practice that has developed by some permitting authorities to use the NAAQS SILS to exempt sources from increment analysis is concerning. It is particularly troublesome for 24-hours PM_{10} Increment, for which the 24-hour NAAQS is five times the allowable PSD increment and the NAAQS SIL represents is about one sixth of the increment.[90] In other words, just seven projects could consume the entire increment, while reliance on the SILs would exempt all of them from increment analysis and none would be required to reduce emissions and none would be denied a permit. Applied to the proposed plant, the use of SILs to avoid more detailed analysis of increment consumption ignores the real possibility that the proposed plant, in conjunction with surrounding sources, would cause violations of PSD increments (as well as potentially contribute to NAAQS violations).

As noted by this comment, the use of SILs for analyses for PSD increments is well established practice, which has been recognized by USEPA in the NSR Manual.[91] While the NSR Manual may be labeled a draft document, it is nevertheless authoritative guidance for implementation of the PSD Program and is routinely relied upon.[92] Moreover, SILs represents a reasoned technical approach to the extent of air quality analysis that is required under the PSD program to the magnitude of a proposed project's impacts. The effort for both the applicant and permitting authority for a detailed air quality analysis is avoided when the air quality with a proposed project will not be significantly different, as defined by the SIL, from current air quality for a particular pollutant and averaging time. Finally, the hypothetical example put forth in this comment does not provide a reasoned basis to deviate from this practice. It reflects a scenario that is improbable, as well the "cooperation" of the permitting authority in overlooking the potential combined effect of a number of small projects at a particular location.[93] It certainly does not reflect the circumstances of the proposed plant, which is in an undeveloped rural area over 10 miles from the nearest regional center, Mount Vernon, a city of about 16,000 people.

81. I am unable to run a full increment analysis because the Illinois EPA has not identified the increment consuming sources, with emission rates, locations, stack heights, etc.

---

[90] By contrast, the 24-hour SIL for PM is one thirtieth of the 24-hour NAAQS for PM_{10}. ($150\ \mu/m^3 \div 5\mu/m^3 = 30$)

[91] **As demonstrated by the discussion of SILs in the NSR Manual, the use of SILs in modeling to address PSD increments was established practice when the PM_{10} increments were adopted. If USEPA had determined that different SILs should be established for PM_{10}, it had the ability to do so. Indeed, as already discussed, USEPA is currently engaged in rulemaking to evaluate whether new SILs should be set for $PM_{2.5}$, and if so at what level.**

[92] **The exception to reliance on the NSR Manual is if the guidance provided by the NSR Manual is contrary to or contradicted by provisions of new laws or rules, superseded by subsequent USEPA policy, or decisions of the EAB or the courts. Such circumstances, which would justify "ignoring" the NSR Manual, are not present with respect to use of SILs.**

[93] **The scenario is improbable as it assumes both a number of small, "but just barely small" projects at a particular location without the occurrence of any significant projects. In also assumes that these projects would be close enough together and have stack parameters that are sufficiently similar that their short-term, 24-hour impacts would be directly additive.**

Moreover, in circumstance where there has been a project in at a location whose impacts qualify as insignificant, a permitting authority has the ability to request more comprehensive modeling for the PSD increment by a subsequent PSD applicant for a project at or near that location, as the permitting authority finds necessary to protect the PSD increments. One should not assume that a permitting authority would knowingly allow multiple "small" projects at a particular location with the result being an exceedance of the PSD increment. Moreover, as the sources responsible for such exceedance would be obligated to take corrective action to eliminate the exceedance, possibly with restrictions on operation or retrofit of controls, it would be unwise for those sources to proceed with projects in a manner that would results in such an exceedance. The sound course of action would be to proceed in a manner that protects the increment.

The Illinois EPA did not have to expend effort to identify increment consuming sources in Jefferson County as part of the review of the application for the proposed plant because it does not have significant impacts on air quality.[94]

82. In its screening modeling to address the PM_{10} NAAQS, Power Holdings did not use a complete inventory of PM_{10} emission units. Among units that were omitted from modeling are conveyer fugitive emissions from conveyors and fugitive emissions from handling of slag. Had these units been included in the NAAQS analysis, it is very likely that the modeled impacts for PM_{10} would have exceeded both the 24-hour and annual SILs. These emission units must be included in the modeling to accurately assess whether the proposed plant will comply with the NAAQS and PSD increments.

This comment speculates on the existence of emission units at the plant which would not be present. In particular, there will not be fugitive emissions from conveyors as the conveyors would be enclosed in a building. There will not be fugitive emissions from slag handling given the nature of the slag and how it is handled.

Moreover, as SILs are set at low numerical values, numerical impacts above a SIL do not indicate that compliance with the NAAQS or PSD Increments would be threatened. As related to air quality analysis for a particular pollutant under the PSD program, SILs are simply an approach to tailoring the extent of the analysis to the potential impacts of a proposed project.

83. Revised coal receiving and storage operations were included in ENSR's November 2008 AERMOD Addendum Report. The report lists additional PM_{10} emission units associated with this project revision.[95] These PM_{10} sources represent baghouse-controlled emissions for coal drop points along the material handling process stream. However, this report does not assess the emissions associated with the belt conveyors that connect each of these controlled emission points. The application does not indicate that all of these emission points are enclosed and directed to one of the control devices. Nor does the permit include any control equipment for the conveyors. Therefore, it appears that the belt conveyors are uncontrolled fugitive PM_{10} emission sources that were not quantified and assessed in the permit application.

Coal would be handled inside an enclosed building so that any emissions from the conveyors will be captured and controlled. **This practice is required by the Condition 4.7.5(a) of the permit.[96] Accordingly, there will be no fugitive emissions from the coal conveyor system.**

---

[94] It is also quite possible that there are no sources in the vicinity of the plant that consume increment as either the baseline has not been set or sources have not been constructed or modified in the vicinity of the plant after baseline dates were set for Jefferson County. If baseline dates have been set, it is also possible that there have been improvements in air quality so that the permissible increase in ambient concentrations is numerically greater than the applicable increments.

[95] The AERMOD Addendum Report, submittal November 7, 2008, identifies eight baghouse dust collectors with potential particulate matter emissions of 14.3 tons per year, total.

[96] Condition 4.7.2(b) provides that "PM emissions from an affected unit handling a dry material, other than a storage pile for dry material and handling operations associated with the pile, shall be controlled by: (i) Enclosure of the unit so as to prevent visible fugitive emissions, as defined by 40 CFR 60.671, from the affected unit; (ii) Aspiration to a control device designed to emit no more than 0.001 grains/dry standard cubic foot (gr/dscf), which device shall be operated in accordance with good air pollution control practice to minimize emissions. For this purpose, the device shall be a baghouse or other filtration type device unless the Permittee demonstrates and the Illinois EPA concurs that another type of control device is preferable due to considerations of operational safety."

In addition, outdoor storage of coal is limited as Condition 4.7.5(a) of the permit provides that "Coal and other bulk materials that have the potential for PM emissions shall be stored in silos, bins, and buildings, without storage of such materials in outdoor piles except on a temporary basis during breakdown or other disruption in the capabilities of the enclosed storage facilities."

84. The proposed plant will produce a significant amount of waste slag.[97] (The application does not amount of slag produced is not provided in the application.) The disposal of this slag will inevitably create particulate matter emissions. However, the application does not address the emissions from the handling of slag or the accompanying air quality impacts. This is of particular concern given that the plans for the plant have changed and waste slag would no longer be slurried and sent back to the coal mine by pipeline for disposal. Accordingly, Illinois EPA's basis for approving the permit is incomplete and flawed.

Given the plans for the plant, the handling of waste slag will not be a source of particulate matter emissions. This is because of the form of the slag from the gasification process and the manner in which it will be handled, which both act to preclude emissions of particulate. The slag from high-temperature gasifiers, of the type to be used at the plant, leaves the gasifier as a molten stream of material. This material is then cooled with water converting the slag to a solid vitreous, glass-like beads that are not dusty so as to create PM emissions. In addition, while the wet slag is mechanically processed to recover water for reuse, the surface of the slag is wet so that slag will then be handled wet. These conditions are not altered by the way that the slag is shipped from the plant.

85. Would the proposed plant receive its coal feedstock as a slurry by pipeline or in bulk by rail? In this regard, when discussing the feedstock for the proposed plant, page 2-1 of the AERMOD Addendum Report states that "The coal will …be converted into slurry at a facility near the mines." It is not clear whether this is still intended in light of other changes in the plans for the plant for receiving coal by rail rather than (or in addition to) a slurry pipeline.

While Power Holding would like to receive coal for the proposed plant by a slurry pipeline, it has proposed a plant that would have the facilities and capability to receive coal by rail. This is clearly indicated in the AERMOD Addendum Report, which explains that "In the event that the pipeline slurry delivery system is not in place or is temporarily not functional, PHI has designed an alternative system that involves coal delivery by rail and coal transfer operations to the proposed facility." In this regard, the statement quoted in this comment is not actually present on page 2-1 of the AERMOD Addendum Report but instead appears to "paraphrase" a statement in the October 2007 application.

86. The application for the proposed plant fails to quantify the emissions associated with coal crushing at the plant site, which would occur when coal is received by rail. If any amount of coal crushing will take place at the plant, the emissions resulting from that process will be significant. There is no basis for ignoring the emissions associated with these coal crushing operations.

The rail delivery system would be expected to include feeder–breakers to break-up or crush large clumps of coal. These units would be located in the totally enclosed coal handling facility, with emissions controlled by the baghouses that control emissions from this facility. The emissions from these baghouses have been quantified and modeled.

The comment is correct that stored coal would then be pulverized. However, this would take place in an enclosed wet grinding process to produce the slurry feed needed for the

[97] "During the gasification process, slag is produced. This slag is primarily the ash contained in the Herrin coal feedstock. Dewatered slag will go to a slag day tank for temporary storage at the Facility site prior to sale or disposal or for reuse by the Facility." Mostardi Platt Environmental, PSD Construction Permit Application for the Southern Illinois Coal Gasification to Synthetic Natural Gas (SNG) Facility, October 17, 2007, pp. 1-10, 1-11.

gasifiers. Given the nature of the grinding process, emissions should not be expected from the pulverization-grinding-slurrying operation.

87. Pulverizing the coal offsite, yet nearby, as would occur with a slurry pipeline, will also have emissions of particulate matter and air impacts that must be identified. There is no basis for ignoring the emissions associated with coal crushing and other operations that would occur in the vicinity of the proposed plant if coal is obtained by a slurry pipeline. However, these emissions have not been quantified and steps have not been taken to ensure that the emissions will not violate the NAAQS or applicable PSD increments. This must occur before a permit can be issued for the proposed plant.

While Power Holdings would prefer to receive coal as a wet slurry, as the comment notes, the permitting of the proposed plant is not predicated upon receiving coal by a slurry pipeline, much less receiving coal by a slurry pipeline from a particular mine. The permit addresses receiving of coal by rail, which would enable purchase of coal feedstock for the plant from a number of different mines. Accordingly, the permitting of the proposed plant does not need to address offsite impacts from the mine or mines supplying coal feedstock to the plant.

Power Holdings indicates that it plans to buy the coal feedstock for the proposed plant on a commercial basis. It is not developing the plant to obtain its feedstock from a particular coal mine, much less a coal mine in the immediate vicinity of the plant.[98] The gasification technology that would be used at the plant can accommodate the normal range of variability in the plant's intended feedstock, Illinois No. 6 or Herrin coal. As such, the permitting of the plant does not extend to the source of coal for the plant. The source or sources of coal for the plant would be subject to separate permitting as appropriate for their circumstances. Indeed, as the mines supplying coal to the plant already exist, the mines will have already gone through permitting as independent sources. Moreover, as Power Holdings does not know where its coal feedstock would come from, any modeling of impacts at this time would be an academic exercise, entirely theoretical in nature.

88. The draft permit does not mention where or how the proposed plant would be getting its coal. However, the application, states that Power Holdings intends to find a single coal supplier and transport the coal to the plant via pipeline by slurry. Is this still Power Holding's intention? The draft permit may have to be revised to consider a co-location with a coal mine if Power Holdings and its supplier meet the criteria to be a single source.

The permit issued for the proposed plant includes facilities to receive coal by rail, as an alternative to receiving coal by slurry pipeline as originally planned by Power Holdings. These facilities were added to the plans for the plant in a supplement to the application. Accordingly, the permit issued for the plant need not address "co-location" of the proposed plant with a coal mine that would be a single source with the proposed plant.

89. The calculations of PM_{10} emissions from vehicle travel on paved roads, as prepared by Mostardi Platt, assume 90 percent dust control efficiency from water sprays and/or sweeping of roadways. This level of control is virtually unachievable during best-case conditions, and is impossible to

[98] **At this time, the operating coal mines closest to the proposed plant are all over 25 miles away and include Zeigler # 11 in Randolph County, and Razorback and Knighthawk in Perry County. Other operating coal mines are further away. Since fugitive dust emissions have local impact, any impacts from these mines would not affect the area around the proposed plant.**

ensure during worst-case conditions. Neither the applicant nor Illinois EPA has pointed to a single basis for assuming 90 percent control under worst-case conditions. Achieving significant dust control—above that already achieved and accounted for through paving—is extremely difficult. More realistic dust control efficiencies for paved road under *good conditions* will be on the order of 50 percent unless the source continuously sweeps and applies water.[99] This practice is impractical or impossible (especially during winter when watering is prevented by ice formation and de-icing or antiskid materials are applied), rendering 90 percent control unattainable on a continuous basis. In any event, continuous sweeping and watering is not required by the permit or enforceable as a practical matter, so 90 percent control cannot represent the worst-case conditions that must be assumed for modeling. I also note that ENSR, the consultant for the final phase of the application, is familiar with calculating emissions from roadways. In a recent permit application for the Toquop Energy Project, a proposed 1100 MW coal-fired boiler near Mesquite, Nevada, ENSR assumed 75 percent control efficiency for paved roads using water washing and cleaning.[100] While this level of control is also overly optimistic, even for best-case conditions, it is more realistic than the 90 percent control used for roadways at the proposed plant.

As noted by this comment, the permit for the proposed plant is based on 90 percent control of fugitive dust emissions from trucks traveling on roadways.[101] This requires the very rigorous level of control of particulate matter emissions from roadways that is proposed in the application, which is appropriate as these emissions are subject to BACT. It would not be appropriate for emission calculations for roadways to be based on a lower level of control efficiency than that proposed by Power Holdings. As observed by this comment, achievement of the level of control that has been relied upon in the emission calculations could require that there be "continuous" sweeping of plant road under "worst case" conditions for generation of dust emissions. It could also restrict the use of anti-skid materials at the plant during icy weather, necessitating that methods be used that prevent the actual accumulation of ice on roadways.

The permit for the plant sets specific limits on the amount of particulate matter emissions from roadways (Condition 4.8.6) that are reflect the emissions calculations in the application. The permit includes provisions to assure that plant roadways are appropriately controlled to maintain particulate matter emissions within these limits. Roadways are subject to requirements for regular sweeping and other dust control measure to minimize dust emissions (Condition 4.8.5). It also requires measurements of silt loading on plant roadways to develop site-specific emission factors and confirm the effectiveness of the dust control program (Condition 4.8.8). Recordkeeping is also required to verify the actual emissions from roadways from the plant, including records for the implementation of the road dust control program, the amount of road traffic at the plant, and the amount of particulate matter emissions (Condition 4.8.9).

The references cited by this comment do not demonstrate that 90 percent control efficiency is impossible to obtain, especially with modern vacuum sweepers that filter the collected air stream before discharge. In this regard, the cited study by Cowherd and others is over 20

[99] C. Cowherd et al., *Control of Open Fugitive Dust Sources: Final Report*, Midwest Research Institute, September 1988, EPA-450/3-88-008, pp. 2-6, 2-7.
[100] Toquop Energy Project, Class I-B Operating Permit to Construct Application, Document Number 10784-004-400, Submitted to Nevada Division of Environmental Protection, Bureau of Air Pollution Control, July 2007, Appendix 5, Attachment 5A.
[101] The application is actually based on 85 control efficiency for automobile traffic on roadways.

years old.[102] The control efficiency of 75 percent used by ENSR or the Toquop Project serves as support for use of 90 percent control efficiency for the proposed plant, given the difference in control measures for fugitive dust.[103] Likewise, the application prepared by Civil and Environmental Consultants, Inc., for Ohio River Clean Fuels also supports the use of 90 percent control efficiency for paved roads, as this is the value of control efficiency that it used in its emission calculations for this facility.[104]

90. I recalculated PM_{10} emissions from plant roads assuming 75 percent control (despite the fact that this represents unrealistically optimistic conditions, rather than worst case conditions). I then remodeled the air quality impacts using the same methodology used by ENSR for the AERMOD Addendum Report. My modeling showed maximum impacts ranging from 6.11 to 7.52 $\mu g/m^3$ 24-hour average, and 1.50 to 1.63 $\mu g/m^3$, annual average. These impacts all exceed the SILs that were inappropriately used by the Illinois EPA. In other words, with a better-than-worst-case condition of 75 percent control, the project's impacts will easily exceed the threshold needed for conducting detailed air quality analyses to address compliance with the NAAQS and PSD increments. The basis on which Illinois EPA is proposing to issue this permit is therefore flawed. Moreover, as discussed in another comments, the emission factors and assumptions used to estimate the pre-control emission rates were understated. Therefore, when true worst-case conditions are modeled, the impacts are even higher.

The analysis discussed by this comment is not directly relevant to the permitting of the proposed plant and does not show that further air quality analyses should be conducted for PM_{10}. This is because it is based on PM_{10} emissions from roadways that are higher than allowed by the permit.[105]

91. Some of the largest air impacts from the proposed plant are from fugitive particulate matter emissions from roadways. The application calculates emissions from roadways using a formula from USEPA's *Compilation of Air Pollutant Emission Factors*, AP-42, which requires certain variables that must be provided for the equation. One of those variables is silt loading on the road surface. The application assumes 5 g/m^2 (which is incorrectly labeled as 5 grains/ft^2). There is no basis for this value in the record nor any analysis to show that the plant can always achieve this rate of silt loading. Moreover, 5 g/m^2 does not represent a worst-case silt loading. Table 13.2.1-4 in AP-42 contains data from studies of silt loading on industrial paved roads. The silt loading

---

[102] In addition to being over 20 years old, the cited portion of the study by C. Cowherd and others addresses control of particulate matter emissions from "public roadways." As observed in the study, public roadways are distinguished from "industrial roadways," given the difference in ownership and supervisory control of roadways, but also the presence of curbs and relatively light traffic loadings. These are factors that constrain the numerical effectiveness of control of fugitive emissions from such roadways. In contrast, for industrial roads, the study observes that "Mitigative measures may be more practical for industrial plant roads because (1) the responsible party is known; (2) the roads may be subject to considerable spillage and carryout from unpaved areas; and (3) all affected roads are in relatively close proximity, thus allowing a more efficient use of cleaning equipment." Cowherd Study, page 2-11.

[103] The application material for the Toquop project cited by this comment does not indicate use of modern road cleaning equipment. Rather "A control efficiency of 75 percent for PM_{10} has been accounted for periodic watering of paved haul roads when necessary." ***See*** **page 5-17 of Appendix S, Detailed Emissions Calculations from the Toquop application.**

[104] ***See*** **Permit to Install Application: Ohio River Clean Fuels Facility, Module 12, Revision 1, July 2008.**

[105] It should also be observed that the analysis discussed by this comment does not show that the plant would cause violations of the NAAQS or PSD increments for PM_{10}. Based on that analysis and considering monitored background concentrations of PM_{10} from Carbondale, a representative location, the maximum annual concentration of PM_{10} with the plant would still be about half the NAAQS, i.e., about 70 $\mu g/m^3$ 24-hour average and 26 $\mu g/m^3$ annual average, compared to 150 and 50 $\mu g/m^3$, respectively. The plant's impacts would also be less than the applicable PSD impacts, i.e., 7.5 $\mu g/m^3$ 24-hour average and 1.6 $\mu g/m^3$ annual average, compared to 30 and 17 $\mu g/m^3$, respectively.

As such the analysis discussed by this comment serves to confirm that the proposed plant would not threaten air quality for PM_{10} even if emissions were significantly greater than allowed by the permit.

value used to estimate emissions for Power Holdings, 5 g/m^2, is below any of the mean values provided in the Table. Additionally, a mean value does not represent worst-case conditions. The range of values in the Table include silt loading of 400 g/m^2—80 times the value that was used. Unless the permit can ensure, through enforceable and measurable limits, that silt loading will never exceed 5 g/m^2 (which is highly unlikely given the values actually representative of industrial paved roads), the air impact analysis must be redone using worst-case conditions.

This comment does not identify a flaw in the emission calculations for roadways. AP-42 does not provide a range of background or "uncontrolled" silt loadings for chemical processing plants. The value that was used for the silt loading on roadways is consistent with the values of silt loading provided for other categories of industrial facilities. For example, the value for silt loading used in this application, 3.5 g/m^2 (equivalent to 5 gr/ft^2) is within the range for silt loading provided by AP42 for paved road roads at quarries, i.e., 2.4 to 14 g/m^2.[106] As the coal supply for the proposed plant would be received by rail and the plant's primary product, SNG, would be shipped by pipeline, it is reasonable to expect that the silt loading on roads at the proposed plant would be at the low end of the range for quarries, where large quantities of commodities are typically handled by truck.

In addition, as already discussed, the permit for the plant includes requirements to measure silt loadings on roadways (Condition 4.8.8). It also includes specific limits on the amount of particulate matter emissions from roadways (Condition 4.8.6). Power Holdings must operate and maintain the plant to comply with these emission limits irrespective of the emissions calculations or other data provided in the application for particulate matter emissions from roadways.

92. Worst case emissions must match the air quality standards and increment for which the emission rates are being used to model. For the proposed plant, Power Holdings uses Equation 2 in Section 13.2.1 of AP 42. However, that equation estimates emission rates over 30-day, or longer, periods of time. It is not to be used for shorter-term periods, such as 24-hours. For example, Equation 2 accounts for periods with rainfall within a 30-day period. Worst-case conditions during a 24-hour period, however, would involve no rainfall during that period. To analyze 24-hour worst-case air impacts, Equation 1 of section 13.2.1 must be used. If that equation is used, it results in a 29% increase in PM emissions than used in the modeling for the application.

This comment does not identify a flaw in the modeling that was conducted for the proposed plant. Notwithstanding the claim made in this comment, modeling for emissions from roadways is commonly conducted using average values for emissions. This is likely the result of many factors, including the method by which emissions from roadways are calculated and the effect of precipitation on emissions. It also accounts for the localized effect of road dust emissions as they occur at ground level in the vicinity of a source.

Moreover, assuming for purposes of discussion, that the comment is correct with respect to how modeling should be performed, the comment neglects the 20 percent "safety factor" that was also included in the emissions calculations for roadways at the proposed plant. As such, the emission rates and modeled impacts from roadways would be off by only 9 percent (29 – 20 = 9). This is not sufficient to invalidate the air quality analysis performed for the

---

[106] By way of comparison, the Toquop project in Nevada used a silt loading of 2.4 g/m^2, which is lower than the 3.5 g/m^3 used for the proposed plant (5 $grains/ft^2$ is equivalent to 3.5 g/m^2) . *See* Application Page 17-12: Exhibit 391-1a.

proposed plant, to show that the proposed plant would threaten violations of the NAAQS or PSD increments.

93. Condition 3.6(a) of the draft permit states that the particulate matter emission limits in the permit are for filterable particulate only.[107] However, the air quality modeling for the plant assumed that the filterable-only PM emission rates were the emission rates for total PM, including condensable particulate. There was no effort to quantify the condensable fraction PM/ PM_{10}. For example, the modeling of the auxiliary boiler used a short term PM_{10} emission rate of 1.638 g/sec, which equals 13 pounds per hour. This corresponds to the limit in Condition 4.2.6 of the draft permit, which is 12.8 pounds per hour for filterable particulate.[108] Condensable particulate impacts ambient air quality. However, those impacts have been ignored in the air quality analysis done for the proposed plant. The permit must either limit total PM/ PM_{10} (on the same or shorter time period as the NAAQS and increment), or Illinois EPA must determine the condensable fraction PM/ PM_{10} and include those emissions in the modeling.

This comment identifies a flaw in the draft permit, not the air quality analysis that was conducted for the proposed plant, which was properly conducted as previously discussed. In response to this comment, the issued permit includes limits for emissions of "total particulate matter," i.e., the combination of filterable and condensable particulate, for the superheaters and auxiliary boiler. These are the units, as this comment observes, for which the limits on particulate matter emission that would have been set by the draft permit would not have matched the emission rates used in modeling.[109] This "correction" has been accomplished with the addition of notes in Condition 4.2.6 in the issued permit.[110]

94. Power Holdings conducted its air quality modeling using five years of meteorological data (2002 through 2006) collected by the National Weather Service (NWS) from the Barkley Regional Airport, near Paducah Kentucky (Paducah Airport). Use of the meteorological data from this air port is unacceptable for a number of reasons.

The air quality modeling appropriately used meteorological data from the Paducah Airport (Barkley Regional Airport) in Kentucky (as well as data for certain meteorological data collected by the NWS at the Lincoln Logan County Airport in Illinois). This data can be considered representative of the meteorology at the site of the proposed plant site, i.e., these airports and the proposed plant are all at rural sites, with similar surrounding land use, in a region of relatively flat terrain such that meteorology is not influenced by nearby landforms. The USEPA's Guideline on Air Quality Models (40 CFR Part 51, Appendix W, Section 8.3.1.2) indicates that five years of off-site, data, as were used for the modeling of the proposed plant, are acceptable for air quality modeling when the NWS data would be representative of the site of a proposed project.[111]

---

[107] In addition, while Condition 3.6(a) states that condensable particulates may be accounted in the sulfuric acid limits, Condition 4.2.2 would not set limits for emissions of sulfuric acid mist for the superheaters or auxiliary boilers.

[108] Similarly, short-term PM_{10} impacts assumed an emission rate of 0.378 g/sec from the superheaters which equals 3.0 pounds per hour. This corresponds to the permit limit of 3.0 pounds per hour PM of filterable PM only.

[109] For the superheaters and auxiliary boiler, condensable particulate would have been excluded from the coverage of the particulate matter limits set by Condition 4.2.6 of the draft permit by the terms of Condition 3.6. In addition, separate limits were not set in Condition 4.2.6 for emissions of sulfuric acid mist from these units.

[110] The notes overrule Condition 3.6 as applied the superheaters and auxiliary boiler, providing that the limits for particulate matter for these units apply to total particulate matter, including both filterable and condensable particulate.

[111] Refer to USEPA's Guideline on Air Quality Models, Appendix W to Part 51

"8.3 Meteorological Input Data

a. The meteorological data used as input to a dispersion model should be selected on the basis of spatial and climatological (temporal) representativeness as well as the ability of the individual parameters selected to characterize the transport and

95. The dispersion modeling for the proposed plant should use site-specific meteorological data rather than data from the Paducah Airport, which is located roughly 67 miles south of the site of the proposed plant.

The air quality analysis for the proposed plant was properly conducted using meteorological data from the Paducah Airport rather than data from a site-specific monitoring station set up in the vicinity of the proposed plant. Even though the Paducah Airport is many miles distant from the site of the proposed plant, meteorological data from the Paducah Airport can be used in a manner that is more than adequate to assess the potential air quality impacts from the plant. Among other things, this is because of the topography and weather patterns of the geographical region in which both the plant site

---

dispersion conditions in the area of concern. The representativeness of the data is dependent on: (1) The proximity of the meteorological monitoring site to the area under consideration; (2) the complexity of the terrain; (3) the exposure of the meteorological monitoring site; and (4) the period of time during which data are collected. The spatial representativeness of the data can be adversely affected by large distances between the source and receptors of interest and the complex topographic characteristics of the area. Temporal representativeness is a function of the year-to-year variations in weather conditions. Where appropriate, data representativeness should be viewed in terms of the appropriateness of the data for constructing realistic boundary layer profiles and three dimensional meteorological fields, as described in paragraphs (c) and (d) below.

b. Model input data are normally obtained either from the National Weather Service or as part of a site specific measurement program. Local universities, Federal Aviation Administration (FAA), military stations, industry and pollution control agencies may also be sources of such data. Some recommendations for the use of each type of data are included in this subsection.

c. Regulatory application of AERMOD requires careful consideration of minimum data for input to AERMET. Data representativeness, in the case of AERMOD, means utilizing data of an appropriate type for constructing realistic boundary layer profiles. Of paramount importance is the requirement that all meteorological data used as input to AERMOD must be both laterally and vertically representative of the transport and dispersion within the analysis domain. Where surface conditions vary significantly over the analysis domain, the emphasis in assessing representativeness should be given to adequate characterization of transport and dispersion between the source(s) of concern and areas where maximum design concentrations are anticipated to occur. The representativeness of data that were collected off-site should be judged, in part, by comparing the surface characteristics in the vicinity of the meteorological monitoring site with the surface characteristics that generally describe the analysis domain. The surface characteristics input to AERMET should be based on the topographic conditions in the vicinity of the meteorological tower. Furthermore, since the spatial scope of each variable could be different, representativeness should be judged for each variable separately. For example, for a variable such as wind direction, the data may need to be collected very near plume height to be adequately representative, whereas, for a variable such as temperature, data from a station several kilometers away from the source may in some cases be considered to be adequately representative. …

8.3.1 Length of Record of Meteorological Data

8.3.1.1 Discussion

a. The model user should acquire enough meteorological data to ensure that worst-case meteorological conditions are adequately represented in the model results. …

8.3.1.2 Recommendations

a. Five years of representative meteorological data should be used when estimating concentrations with an air quality model. Consecutive years from the most recent, readily available 5-year period are preferred. The meteorological data should be adequately representative, and may be site specific or from a nearby NWS station. Where professional judgment indicates NWS-collected ASOS (automated surface observing stations) data are inadequate {for cloud cover observations}, the most recent 5 years of NWS data that are observer-based may be considered for use….

8.3.2 National Weather Service Data

8.3.2.1 Discussion

a. The NWS meteorological data are routinely available and familiar to most model users. Although the NWS does not provide direct measurements of all the needed dispersion model input variables, methods have been developed and successfully used to translate the basic NWS data to the needed model input. Site specific measurements of model input parameters have been made for many modeling studies, and those methods and techniques are becoming more widely applied, especially in situations such as complex terrain applications, where available NWS data are not adequately representative. However, there are many model applications where NWS data are adequately representative, and the applications still rely heavily on the NWS data. …

8.3.2.2 Recommendations

a. The preferred models listed in Appendix A all accept as input the NWS meteorological data preprocessed into model compatible form. If NWS data are judged to be adequately representative for a particular modeling application, they may be used. …

and Paducah Airport are located, which result in similar weather from year to year at both locations. The use of five full years of meteorological data, rather than the year of data that would be used if a site-specific data were collected, ensure that the full range of meteorological conditions that would be experienced at the project site are modeled.

96. The quality of the meteorological data collected at the Paducah Airport is such that is not acceptable for air dispersion modeling for the proposed plant. The modeling for the proposed plant must be redone to determine with more representative meteorological data. This is because there are significant differences in land uses comparing this airport and the proposed plant site. The Paducah Airport is comprised of concrete runways, parking lots, passenger terminals, and other structures associated with air travel activities. These surface and building characteristics, in turn, affect the boundary layer meteorology present at the airport. In addition, landings, takeoffs, and idling of airplanes affect the site-specific conditions at the airport such that the meteorological conditions are not representative of the area surrounding the proposed plant.

The Paducah Airport data is representative and was appropriate used in the modeling conducted for the proposed plant. At airports, meteorological data is collected at weather stations that are located to avoid influence from the various features and activities listed in this comment, as their purpose is to collect data that is representative of the region, including data is for aircraft, i.e., aircraft in flight approaching or departing from the airport. The data is also collected above ground level on elevated towers to avoid the influence of surface effects. If weather data were collected that was influenced by surface effects, structures, or operation of aircraft on the ground, the data would not serve its intended purposes. Moreover, although the Paducah Airport extends over almost a thousand acres, only a fraction of that area actually developed. It is a "small" airport currently used mostly used for general aviation rather than commercial aviation. As previously discussed, the use of NWS data is routinely considered acceptable by USEPA for modeling unless complex terrain is present. The long period of model simulation (five years) ensures that worst-case meteorological conditions are modeled to appropriately identify maximum air quality impacts of a proposed project.

97. Power Holdings performed supplemental AERMOD dispersion modeling to assess PM_{10} impacts from the plant with receipt of coal by rail. As part of that modeling analysis, ENSR, prepared AERMOD input meteorological data using surface characteristics surrounding the Paducah airport.[112] ENSR, however, only examined the surface characteristics at the airport, and ignored the conditions at the project site. This fails to ensure that the surface characteristics of the Paducah Airport are representative of the proposed plant site. The AERMOD Implementation Guide clearly provides dispersion modeling must be conducted with representative meteorological data, with consideration of the difference in the character of the site of the proposed project and the site at which meteorological data was collected.[113] If representative

---

[112] ENSR Corporation, AERMOD Addendum Report, Southern Illinois Coal to SNG Facility: Including Coal Receiving and Storage, Document Number 12730-001-0400, November 2008, pp. 3-1 to 3-7.

[113] When discussing the representativeness of meteorological data, USEPA states:

"3.1.1 Meteorological data representativeness considerations:

When using National Weather Service (NWS) data for AERMOD, data representativeness can be thought of in terms of constructing realistic planetary boundary layer (PBL) similarity profiles and adequately characterizing the dispersive capacity of the atmosphere. As such, the determination of representativeness should include a comparison of the surface characteristics (i.e., z0, *Bo* and *r*) between the NWS measurement site and the source location, coupled with a determination of the importance of those differences relative to predicted concentrations. Site specific meteorological data are assumed by definition to be representative of the application site; however, the determination of representativeness of site-specific data for AERMOD applications should also include an assessment of surface characteristics of the measurement and source locations and cannot be meteorological data is not available from an existing weather station, an applicant must collect site-specific meteorological data prior to modeling project impacts. Here, however, Power Holdings did not prepare any analyses to determine whether the surface characteristics for the Paducah Airport are representative of the proposed plant site. This failure is particularly alarming as the applicant used monthly weather conditions and segment-averaged surface characteristics representative of the Paducah Airport, which are very unlikely to be the same weather and sector-specific surface conditions as those at the plant site. Since modeled impacts are highly dependent on surface characteristics, the failure to use representative meteorological data means that the modeling that was done cannot be used in assessing whether the proposed plant would comply with NAAQS and PSD Increments.

This comment does not demonstrate that the data collected at the Paducah Airport is not representative of the proposed site due to differences in the two sites, including surface roughness. The Paducah Airport, which is actually located about 12 miles west of Paducah, is located in a rural area with surrounding terrain and other characteristics that are sufficiently similar to those at the site of the proposed plant to enable meteorological data from the Paducah Airport to be used for modeling of the proposed plant. The November 18, 2008 AERMOD Modeling Report[114] discusses the surface characteristics of the project site and the Paducah Airport, showing that data from the Paducah Airport should be considered be considered representative and acceptable. **AERMET characterizes sites by a number of factors including, including land cover, surface roughness, albedo, and Bowen ratio, which were addressed in the AERMOD Report.[115, 116]**

---

based solely on proximity. The recommendations presented in this section for determining surface characteristics for AERMET apply to both site-specific and non-site-specific (e.g. NWS) meteorological data.

The degree to which predicted pollutant concentrations are influenced by surface parameter differences between the application site and the meteorological measurement site depends on the nature of the application (i.e., release height, plume buoyancy, terrain influences, downwash considerations, design metric, etc.). For example, a difference in z0 for one application may translate into an unacceptable difference in the design concentration, while for another application the same difference in z0 may lead to an insignificant difference in design concentration. If the reviewing agency is uncertain as to the representativeness of a meteorological measurement site, a site-specific sensitivity analysis may be needed in order to quantify, in terms of expected changes in the design concentration, the significance of the differences in each of the surface characteristics.

If the proposed meteorological measurement site's surface characteristics are determined to NOT be representative of the application site, it may be possible that another nearby meteorological measurement site may be representative of both meteorological parameters and surface characteristics. Failing that, it is likely that site-specific meteorological data will be required."

AERMOD Implementation Guide, Last Revised: January 9, 2008, pp. 3 - 4

[114] See November 19, 2008 application submittal.

[115] **Excerpt from AERMOD Report, November 2008 "AERMET was run using the same meteorological stations as for the previous modeling, Paducah-Barkley Regional Airport, KY as the surface site, and Lincoln Logan County Airport, IL as the upper air site."**

"AERMET requires specification of site characteristics including surface roughness (z_o), albedo (r), and Bowen ratio (B_o). These parameters were developed according to the guidance provided by USEPA in the recently revised AERMOD Implementation Guide (AIG).

The revised AIG provides the following recommendations for determining the site characteristics:

1. **The determination of the surface roughness length should be based on an inverse distance weighted geometric mean for a default upwind distance of 1 kilometer relative to the measurement site. Surface roughness length may be varied by sector to account for variations in land cover near the measurement site; however, the sector widths should be no smaller than 30 degrees. As discussed further below 2 sectors were used in this application..**
2. **The determination of the Bowen ratio should be based on a simple un-weighted geometric mean (i.e., no direction or distance dependency) for a representative domain, with a default domain defined by a 10km by 10km region centered on the measurement site.**
3. **The determination of the albedo should be based on a simple un-weighted arithmetic mean (i.e., no direction or distance dependency) for the same representative domain as defined for Bowen ratio, with a default domain defined by a 10 km by 10 km region centered on the measurement site.**

The AIG recommends that the surface characteristics be determined based on digitized land cover data. USEPA has developed a tool called AERSURFACE that was used to determine the site characteristics based on digitized land cover

Moreover, "representativeness" does not require that the weather in the area at which the meteorological data was collected and the proposed project must be coinstantaneous, always having the same weather at the same time. Representativeness only requires that the weather, as would occur at both sites, be sufficiently similar that the collected meteorological data would cover or portray the range of weather at the project site, on both a short-term and annual basis.

98. For purposes of air dispersion modeling, airport data is the least desirable because it suffers problems related to location and quality. The USEPA's *Meteorological Monitoring Guidance for Regulatory Modeling Applications*[117] notes the general concern about airport data:

> For practical purposes, because airport data were readily available, most regulatory modeling was initially performed using these data; however, one should be aware that airport data, in general, do not meet this guidance. Guidance, Page 1-1

Modeling for the proposed project was conducted with the AERMOD model, which requires specific data to characterize the atmospheric boundary layer and upper air dispersion. The meteorological data collected at the Paducah Airport is not adequate to provide AERMOD with the necessary data to provide realistic results, that is, the results of AERMOD with airport data are not the most representative of real conditions. Airport data (like that from the Paducah Airport) is not collected for purposes of air dispersion modeling. For example, the data is recorded and reported once per hour, based on a single visual reading (usually) taken in the last ten minutes of each hour. This does not meet USEPA's recommended practice of automatically recording data multiple times per hour to calculate hourly-averaged data. Additionally, data collected at the Paducah Airport is not subject to the recommended system accuracies. The USEPA recommends that meteorological data be collected with equipment sensitive enough to measure all conditions needed to verify compliance with the NAAQS and PSD increments.[118]

---

data in accordance with the recommendations from the AIG discussed above. AERSURFACE incorporates look-up tables of representative surface characteristic values by land cover category and seasonal category. AERSURFACE was applied with the instructions provided in the AERSURFACE User's Guide (EPA, 2008).

The current version of AERSURFACE (Version 08009) supports the use of land cover data from the USGS National Land Cover Data 1992 archives (NLCD92). The NLCD92 archive provides data at a spatial resolution of 30 meters based on a 21-category classification scheme applied over the continental U.S. Visual inspection of recent satellite images (2006) over the Paducah-Barkley Regional Airport, KY (see Figure 3-1), compared to the 1992 land cover images (Figure 3-2) indicate that there have been no significant changes in land use cover confirming the use of the 1992 data was reasonable.

As recommended in the AIG for surface roughness, the 1 km area was broken down into sectors for the analysis. Four sectors were identified for this analysis based upon visual observation of the land-use about the plant as shown on an aerial photograph (see Figure 3-3). Note that the 1-km radius is centered on the anemometer location ….

In addition, for Bowen ratio the land use values are linked to three categories of surface moisture corresponding to average, wet, and dry conditions. The surface moisture condition for the site may vary depending on the meteorological data period for which the surface characteristics will be applied. AERSURFACE applies the surface moisture condition for the entire data period. Therefore, if the surface moisture condition varies significantly across the data period, then AERSURFACE can be applied multiple times to account for those variations. As recommended in AERSURFACE User's Guide, the surface moisture condition for each month was determined by comparing precipitation for the period of data to be processed to the 30-year climatological record, selecting "wet" conditions if precipitation was in the upper 30th-percentile, "dry" conditions if precipitation was in the lower 30th-percentile, and "average" conditions if precipitation was in the middle 40th-percentile. …"

[116] **For a less technical assessment of the two sites, consider Figures 1-1 (Proposed Southern Illinois Coal to SNG Facility Location) and 3-1 (Region Around Paducah-Barkley Regional Airport, KY) shows the similarity of land use between the two locations, mostly agricultural activities with a small percentage of the land occupied by trees in both cases.**

[117] USEPA, Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-454/R-99-05, February 2000, p. 1-1 (*available at* http://www.epa.gov/scram001/guidance/met/mmgrma.pdf).

[118] For example, low wind speeds (less than or equal to 1.0 meter per second) are usually associated with peak air quality impacts, as impacts are inversely related to wind speed. USEPA guidance provides that anemometers to measure wind speed

While meteorological data collected at the Paducah Airport may have certain deficiencies, as noted by this comment, this data is still appropriately used for the air quality analysis conducted for the proposed project.[119] Moreover, this comment does demonstrate that the presence of any such deficiencies in the meteorological data affected the results of the modeling for the proposed project in any meaningful way. As a general matter, the presence of any deficiencies in the meteorological data is addressed by the fact that the dispersion modeling was conducted over a period of five years rather than for a period of one year, as would otherwise be acceptable if site-specific meteorological data had been collected for the proposed project. This increase in the breadth of the duration of the modeling simulation compensates for the difference in the quality of meteorological data that might have been available if a site-specific meteorological data had been collected.

In this regard, this comment selectively quotes from the cited USEPA document, overlooking statements in that document confirming the acceptability of meteorological data collected at airports, as well as the need to routinely rely on certain meteorological data that is typically only available from the NWS. Stations at airports In particular, the cited document, USEPA specifically addresses meteorological data collected at airports, confirming that it is generally acceptable for modeling.[120] Moreover, it is also relevant that the cited document is specifically directed at appropriate practices for collection of meteorological data when a project-specific weather station is established for the specific purpose of collecting data to support development of regulations.[121] The document does not directly address the collection of meteorological data for support of PSD applications, much less appropriate procedures for performance of PSD modeling. These are the subject of different guidance documents prepared by USEPA, notably USEPA's various guidelines on air quality modeling. In this regard, in accordance with USEPA's current Guideline on Air Quality Models, as already discussed, USEPA has specifically considered and allowed for the use of NWS meteorological data, as collected at airports, with AERMOD.

---

should have a starting threshold of no more than 0.5 meter per second and measurements should be accurate to within plus or minus 0.2 meter per second, with a measurement resolution of 0.1 meter per second. However, the Paducah Airport is not in 0.1 meter per second increments but instead in whole knots. This was confirmed by an examination of the meteorological data files for the Paducah Airport. The data for wind speed was originally in whole knots, not to the nearest tenth of knot. The hourly data from the Paducah Airport was then converted from knots to meters per second. Data meeting USEPA's guidance would not have whole knot values for each hour. The data in whole knots does not meet USEPA's guidance and also does not account for the low wind speeds that are associated with the highest air quality impacts.

[119] The comment regarding "rounding" of data with 3 knots is not appropriate or relevant. The data for wind speed from the Paducah Airport, as provided by the National Data Climatic Center, is already in meters/second (with values indicating with more precision than integer knots) and were directly input to AERMET without conversion or rounding.

[120] I**n Section 6.7 of *Meteorological Monitoring Guidance for Regulatory Modeling Applications,* USEPA states "Although data meeting this guidance are preferred, airport data continue to be acceptable for use in modeling. In fact observations of cloud cover and ceiling, data which traditionally have been provided by manual observation, are only available routinely in airport data; both of these variables are needed to calculate stability class using Turner's method (Section 6.4.1). The Guideline on Air Quality Models [1] recommends that modeling applications employing airport data be based on consecutive years of data from the most recent, readily available 5-year period."**

[121] **USEPA's *Meteorological Monitoring Guidance for Regulatory Modeling Applications,* EPA-454/R-99-005, USEPA, Office of Air Quality Planning and Standards, February 2000, as referenced by this comment, does not apply to collection of data by the NWS, which as already discussed, is acceptable for modeling if certain conditions are met, e.g., a full five years of data is modeled. Rather, this document provides guidance for meteorological monitoring programs under the control of a permit applicant or permitting authority. "Guidance is provided for the in situ monitoring of primary meteorological variables (wind direction, wind speed, temperature, humidity, pressure, and radiation) for remote sensing of winds, temperature, and humidity, and for processing of derived meteorological variables such as stability, mixing height, and turbulence." Page 1-1**

99. Another problem with the meteorological data from the Paducah Airport is its low quality. Because of this, the modeling for the proposed plant does not adequately assess the plant's impacts, to ensure that the plant would comply with NAAQS and PSD Increments. In particular, calms make up 18.3 percent of the Paducah data set, which is an unacceptably large percentage. When properly measured with modern anemometers, there are typically only a few calm hours per year. For example, the monitoring data set for the proposed Newmont coal-fired power plant in Nevada has five calm hours in the one-year period spanning 2003 and 2004. The use of a meteorological data set with such a high percentage of calm hours means that the modeling tended to disregards periods where the air quality impacts may be greatest. This is because AERMOD "skips over" calms, identified as hours when the reported wind speed is 0.0 meter/second. However, at airports any wind speed less than three knots (1.54 meters/second) is regarded as calm. Low wind speeds are of concern for air quality modeling, as the highest air impacts can often occur during the lowest wind speeds. Using data with no wind speeds less than three knots biases the modeling in a way that avoids identifying the highest impacts. Measurements of wind speeds are needed down to 0.5 meter/second, greatly increasing the number of hours included in the modeling analyses. The Paducah Airport data also lacks data for 3.7 percent of the hours. Together, the calm and missing hours make up over 22 percent of the total data set, so the modeling analysis is based on only 78 percent of the possible data (which I know excludes the 18 percent that would show the highest concentrations).

This comment does not show that the meteorological data from the Paducah Airport was inadequate for the purpose for which it was used, i.e., the modeling of the proposed plant to demonstrate that it would not threaten the NAAQS or PSD Increments. The Paducah Airport data was collected by the NWS, which is an authoritative source for such data, as it is an government agency that specializes in the collection of weather data. The data collected by the NWS at Paducah Airport meets USEPA's criteria for acceptable data as the percentage of missing data is within 10 percent. As such, data from the NWS weather station at the Paducah Airport, a site whose weather would be similar to and representative of weather at the location of the proposed project, can be relied upon for modeling of the proposed plant.[122] As AERMOD is an approved model for PSD modeling, the manner in which it currently addresses calms does not alter this conclusion.[123]

Moreover, the wind speed data collected for the proposed Newmont Nevada Energy power plant project near Dunphy Nevada, which is the only factual support provided with this comment, should not be considered to be indicative of wind speeds in Illinois. That project would be located in the high desert of north central Nevada, an area that is not at all representative of the meteorology in Illinois. The percentage of calm winds in the Paducah Airport data is more similar to the levels recorded at weather stations in central Illinois.

100. The modeling for this project is also biased because the wind speed data was inappropriately rounded up when converted from whole knots to meters/second. For example, the lowest wind speed reported by the Paducah Airport is 3.0 knots, which is 1.54 meters/second. The modeling reports these minimum wind speeds as 1.60 meters/second. Again, since modeled impacts are inversely related to wind speed, by rounding wind speeds up, impacts were under-predicted. If any rounding was to be done, 3.0 knots should have been modeled as 1.50 meters/second.

---

[122] Calms and missing data would also be present if meteorological data was collected by a site-specific monitoring station. In addition, concerns could be present about the data collected at such a station as it would be operated for a limited period of time at a remote, unmanned site, by a contractor working for Power Holdings.

[123] USEPA is working with modelers to develop refinements to AERMOD that would improve the way in which calms and missing data are handled.

This comment is not relevant, since the raw data provided by the National Data Climatic Center are already in meters per second (with values indicating wind speeds with more precision than integer knots) and were provided directly to AERMET without a need for conversion or rounding. Sources are not in a position to question or manipulate the government-provided meteorological data. In addition, given the conservative nature of the dispersion models used for air quality analyses, it is unrealistic to expect that the slight difference in winds speeds that resulted from the rounding practices of the National Data Climactic Center in handing of data, either rounding upwards or downwards, would have any effect on the conclusions from the air quality modeling for the proposed plant.

101. As well as base meteorological data, the data used for modeling of the proposed plant must also include data for multiple elevations above the ground. Using NWS surface observations for the vertical wind and turbulence profile, as was done, may be acceptable for specific low-level releases (less than the anemometer height), but is not acceptable for the elevated stacks that would be present at the proposed plant.[124] The AERMOD profile data will contain only one "upper air" profile, and it will use the exact same values as the surface data collected at the Paducah Airport. In other words, the modeling for the proposed plant uses surface data instead of profile data, thus completely invalidating the assessment of the impacts from the plant's 300 foot tall flare stacks. This also means that there are no meaningful wind data for modeling impacts from the proposed boilers, thermal oxidizers, cooling towers, baghouses and other units with effective stack heights much higher than the available wind measurements. [125] Data for wind speed, direction, and temperature measured only 10 meters above the ground is not reliable for use in a sophisticated boundary layer characterization model, such as AERMOD, which means that the modeling results are meaningless.

The factors discussed in this comment to do not invalidate the modeling that was conducted for the proposed plant, as they are addressed by the "design" of AERMOD model and how metrological data is handled by the model. In particular, the model does not require meteorological data collected at multiple heights.[126] Use of meteorological data collected from only a single height, instead of data from multiple heights, leads to conservative, i.e., high, modeled impacts. This is because AERMOD uses a conservative assumption for the vertical temperature gradient in the absence of measured data from multiple elevations. In addition, the effect of using a single wind direction, rather than different wind directions at different elevations, is to combine impact for all plumes in one direction rather than spreading them out as wind direction differs based on elevation above the ground. In this regard, given the meteorology that was used for the modeling for the plant, the modeling did not rely on the capability of AERMOD to be used as a "sophisticated boundary layer characterization model," which would have shown lower air quality impacts from the plant. However, as the modeling for the plant was conducted in a manner that provided

[124] This is because the data lacks both a vertical wind profile and any measurements of the fluctuating components of the wind. Examining the applicant's AERMOD profile data, it is clear that the "upper air" observations that were used were not upper air at all, but are instead the surface winds measured near ground level with a single anemometer located at an elevation of 10 meters.

[125] As meteorological data at the Paducah Airport is collected only at a single elevation 10 meters above the ground, the data does not include measurements of fluctuating components of the wind. These are measured as standard deviations of either wind speed or wind direction, in both the vertical and horizontal planes. These data (along with other parameters such as wind speed, direction, and temperature) are necessary to characterize plume dispersion, and must be measured at various heights to give a meaningful depiction of the plant's elevated emission plumes.

[126] The exception is "upper air data," which is also needed for modeling and includes upper air soundings and mixing height above the ground surface. Data for these parameters cannot be collected by weather towers, given the heights at which the measurements must be made. Upper air data is instead obtained by other methods, i.e., weather balloons. Upper air data was collected at the Paducah Airport until 1995, when this function was transferred to the NWS station in Lincoln, Illinois.

conservative, i.e., high, results, those results can properly be relied upon for the permitting of the proposed plant and are not meaningless.

102. The Illinois EPA stated that Power Holdings submitted a Class I air impact analysis for the proposed plant, and based on that report concluded that there will be no Class I air quality violations.[127] However, I have not been able to review a report for this analysis, despite numerous requests for all information comprising the permit record. I am concerned about the project's impacts, alone and cumulatively, at the Mammoth Cave National Park and the Wilderness Area at the Mingo Wildlife Refuge. Since Illinois EPA uses the applicant analysis as a basis for issuing a permit, the analysis should have been available for public review and comment. On the other hand, if no such analysis, then Illinois EPA's basis for approving the permit is without merit.

Given the distance of the proposed plant from Class I areas (over 100 kilometers (km)) and the magnitude of its potential emissions, the emissions of the proposed plant should not be expected to affect any Class I area. In addition, as the proposed plant would be located over 100 km from any Class I area, the nature and extent of analysis to address air quality impacts on Class I areas is at the discretion of the appropriate Federal Land Manager(s). For a proposed project in these circumstances, USEPA guidance recommends that the applicant meet with the appropriate Federal Land Manager(s) early in the permit application process to discuss the extent of analysis that will be required to address a project's potential impacts on Class I Area(s). (NSR Manual, page E.16) This is what took place for this project. These discussions concluded that a very simple screening analysis, based on the proposed plant's potential emissions and distance from Class I areas, was sufficient to address the project. Accordingly, computerized air quality modeling was not needed and was not conducted to evaluate the proposed plant's impacts on either Mammoth Cave National Park or the Wilderness Area at the Mingo Wildlife Refuge.[128]

[127] Finding 6(b) of the draft permit states "Power Holdings also submitted an analysis evaluating the impacts of the proposed project on air quality in Mammoth Cave National Park and the Wilderness Area at the Mingo Wildlife Refuge, which are located approximately 160 kilometers southwest and 270 kilometers southeast, respectively, of the site of the proposed plant. This analysis shows that the plant will not violate the Class I air quality increments applicable in these areas. The Illinois EPA has determined based on the assessment submitted by Power Holdings that the proposed plant would not have an adverse impact on air quality values in these areas."

[128] The following is the sequence of events that took place with respect to consideration of impacts on Class I Areas::

1. At Power Holdings' request, ENSR prepared a Class I Modeling Protocol, which was submitted to the Federal Land Manager and Illinois EPA in January 2008.

2. Power Holdings and ENSR and made a Summary Presentation concerning the project to the Federal Land Managers and Illinois EPA in February 2008. In that presentation, Power Holdings requested a "*Q/D* Air Quality Review Waiver" from further analysis since the values for Q/D for the proposed plant were within the criteria for such a waiver. (Q/D is calculated as the project's combined potential annual emission of SO_2, NO_x and PM_{10}, in tons per year, divided by the distance from a Class I area in kilometers. The value of Q/D at which further analysis may be waived is 10. For the proposed plant relative to the Mingo Area, which is the closer Class I Area, the Q/D factor would only be about 5 for normal operations and less than 10 for startup operations.)

3. In March 2008, the Federal Land Managers and the USEPA advised that further Class I analysis was unnecessary. On March 18, 2008; Meredith Bond of the USFWS advised that "The project will be approximately 160 km NE of the Mingo Wilderness Area, and 277 km WNW of Mammoth Cave National Park, the two nearest Class I areas, which are managed by the Fish and Wildlife Service, and the National Park Service, respectively. After discussing the project with you and your client last month, and based upon the distance and worst-case emission rates projected for this project, we do not anticipate that emissions from this project will impact air quality related values, including visibility, at Mingo. Thus, I am not requesting Class I modeling for AQRV or visibility impacts for this project. The National Park Service has indicated the same for Mammoth Cave." On March 28, 2008, Randal Robinson of the USEPA advised that: "Given the emissions and distance to Class I areas, it's highly unlikely there will be any substantial impacts in the relevant Class I areas. Consequently, a Class I area increment analysis is unnecessary."

In response to this comment, Finding 6(b) in the issued permit now more clearly explains that a screening analysis was used to address the plant's impacts on Class I Areas.

103. Condition 3.6 of the permit generally requires that annual limits set by the permit must be rolled monthly, which is important for practical enforceability of such limits. However, I am concerned that the source may overlook this provision since Condition 3.6can be so far removed from the limits to which it applies. Condition 3.6 should be linked to the other permit conditions to which it applies.

As Condition 3.6 is an overarching requirement for all annual limits set by the permit, it would be inappropriate to then refer back to Condition 3.6 in each of the subsequent conditions of the permit that sets an annual limit. It would also be cumbersome for all those subsequent conditions to refer back to Condition 3.6 and would risk the possibility that a reference to Condition 3.6 is inadvertently omitted from one or more of those conditions. From a practical standpoint, the source must compile monthly records of emissions, so it will be straightforward for it to determine compliance with annual limits as required.

104. Condition 3.6, which provides for 12-month rolling averages for annual limits, does not address how Power Holdings will demonstrate compliance with these limits prior to having 12 months of data. A practically enforceable method for determining compliance with the annual limits should be developed for the first year.

In the issued permit, another provision has been added to Condition 3.6 to address this comment. To ensure that annual limits are practically enforceable during the first 12 months of operation, the issued permit provides that for the first 12 months of operation, compliance with annual limits shall be determined on a monthly basis from a cumulative total of monthly data. This will enable compliance to be determined on a monthly basis, as is desirable for practical enforceability, during the period before there are 12 consecutive months of data.

105. The permit relies on the provisions of 40 CFR 63.6(e) to set forth the requirements for the Startup, Shutdown and Malfunction (SSM) Plans that Power Holdings must prepare and implement for the proposed plant. Given that the future of certain provisions in 40 CFR 63.6 is not known at this time,[129] the permit should not rely on 40 CFR 63.6 for these provisions. The permit should instead detail the requirements for the SSM plans independent of 40 CFR 63.6.

Changes have made to this permit in response to this comment. However, rather than detailing the relevant requirements of 40 CFR 63.6 in the permit, the issued permit refers to a specific version of 40 CFR 63.6(e) as adopted on a particular date, i.e., April 20, 2006.[130] These references to a specific version of these federal regulations will protect against any subsequent changes to 40 CFR 63.6. In effect, they preserve the version of the regulations that existed and was being referenced when the permit was issued. This approach was taken because it maintained consistency with the provisions in the draft permit. It also avoided the possibility of discrepancies between the provisions of 40 CFR 63.6(e) and a detailed

---

[129] **On December 19, 2008, the United States Court of Appeals for the District of Columbia Circuit vacated, but has yet to finish its evaluation of, 40 CFR 63.6(f)(1) and 63.6(h)(1) of the General Provisions of the NESHAP. These two provisions exempted sources in certain categories from otherwise applicable NESHAP standards during startup, shutdown, and malfunction (SSM) events.**

[130] **The provisions of 40 CFR 63.6 were last revised by USEPA on April 20, 2006 (71 FR 20454). Accordingly, this is also the version of 40 CFR 63.6 that has been in effect during the processing of the application for the proposed plant.**

restating of those provisions in the permit, with interested people having to make a comparison of the two versions of these provisions.

106. The application for the proposed plant is based on the auxiliary boiler operating for no more than 4000 hours per year. However, the permit has no such limit.

Condition 4.2.5(b) of the permit, which limits the annual capacity factor of the auxiliary boiler to no more than 46 percent, effectively limits the operation of the boiler to the level indicated in the application.[131]

107. How often would the syngas be analyzed under Condition 4.2.7-2?

The comment is no longer relevant, since the issued permit does not require periodic analysis of syngas and draft Condition 4.2.7-2 has not been carried over to the issued permit. The draft permit would have required periodic analysis of syngas, as provided by Condition 4.2.7-2, because it would have allowed syngas to be used as a fuel in the superheaters. However, this is no longer allowed by the issued permit, which restricts the superheaters to use of natural gas. Accordingly, there is no longer a need for syngas to be analyzed and Condition 4.2.7-2 is not included in the issued permit. (Note that because of this change, Condition 4.2.7-1 in the draft permit became Condition 4.2.7 in the issued permit.)

108. How often will observations of visible emissions using Method 22 be performed under Condition 4.2.8-2(a)?

Observations of visible emissions from the superheaters and auxiliary boiler would occur in conjunction with routine operation and formal inspection of the operation of the snits. As such, the source would be expected to observe the operation of each of these units, including observing the stacks for the presence of visible emissions, at least once each day that a unit operates.

109. What are the units of measure for the emission limits from the sulfuric acid plants in Condition 4.4.2(b)?

These limits are in terms of pounds per ton of 100 percent acid produced.

111. This action before the Illinois EPA is not a narrow proceeding confined to the proposed plant. The implications are much broader, affecting the environment across the State of Illinois and beyond. The question before the Illinois EPA is whether additional emissions from new uses of coal, including emissions of greenhouse gases (GHG) are acceptable as a matter of public health and environmental policy. The Illinois EPA will, whether it intends to or not, be taking a position on these broader issues when it acts on the application for the proposed plant. Considering the proposed plant's potential emissions of GHG, a permit cannot be issued for the plant, especially when there are cleaner and less expensive alternatives to the project.

In fact, decisions on permit applications should be considered narrow proceedings confined to the project or source that is the subject of the application and governed by current laws

---

[131] The restriction on the capacity factor of the auxiliary boiler is equivalent to operating the boiler at it rated capacity for 4000 hours each year. (8760 hours/year x 0.46 = 4,030 hours/year, ≈ 4000 hours/year)

and rules. In this regard, the application for the proposed plant shows that it would comply with current laws and rules. At the same time, the issuance of a permit for the proposed project does not indicate the emissions of GHG and accompanying global warming and climate change are not critical issues for Illinois, the United States, or mankind and the global environment. However, these issues must be addressed by appropriate means.

112. With a nominal operating life of 50 years, the proposed plant would have energy and environmental implications for decades — when the best science now available says GHG emissions should be reduced by 80 percent. That necessary reduction is frustrated, if not precluded, if the Illinois EPA allows projects like this one, which emits significantly more GHG per unit of output than the alternatives and for which the applicant refuses to commit to capture and sequestration of its carbon dioxide (CO_2) emissions. In short, if the Illinois EPA issues this permit, it will be committing Illinois to a future where CO_2 emissions are not addressed, hindering the rest of the country's and world's efforts to address GHG induced global warming and climate change.

The permitting of the proposed plant is governed by current regulations, which the proposed plant would be developed to comply with. As previously explained, the issuance of this permit does not limit Illinois' broad course of action in the future. It does not preclude legislative or regulatory actions in the future that would address the CO_2 emissions of the plant and require that they be controlled or otherwise mitigated. Issuance of this permit also does not act to block adoption of programs or regulations by the State of Illinois in the future that address Illinois' emissions of CO_2. It also does not shield this plant or other sources in Illinois from national programs that will be adopted in the future to address emissions of CO_2.

113. Coal is not a cheap source of energy. The increasing cost of coal-based plants, combined with the certain future cost of GHG controls, make the plant proposed by Power Holdings an irresponsible investment. If the costs of complying with future requirements for control of GHG are factored in (and maybe even if they are not), cleaner options are more economic. In particular, improved energy efficiency, wind, solar, biomass, and highly-efficient natural gas combined cycle options are commercially available and less costly ways to meet the need for energy. They also have the potential to support Illinois' economy to a greater degree than coal.

Whether the proposed plant is a "responsible investment" is not a matter that is relevant to the issuance of a permit for the proposed plant by the Illinois EPA. The permitting of the proposed plant is based on compliance with applicable laws and rules that would apply to the emissions of the proposed plant.

In addition, as related to investment in the plant, the question is whether the plant would make synthetic natural gas that could be sold at price that is competitive with other sources of natural gas. If this is the case, the plant would be a good investment. However, the answer to that question is a matter of judgment as it involves predicting the future supplies and costs of natural gas from other sources, as well as the assessment of many other factors. As noted by the comment, one aspect in this evaluation could be the extent to which measures to improve energy efficiency affect the usage of natural gas, thereby influencing both the supplies of natural gas and its costs.

114. Other states have shown the path to a clean energy future. For example, in Kansas, Governor Sebelius rejected two proposed 700 MW coal-fired generating units because of concerns over CO_2 emissions and the potential costs of federal regulations for CO_2 emissions. She said "We

must move forward strategically—steering our state clear of the environmental, health and economic risks of massive new carbon emissions."[132] Such progress in the fight against global warming would be wiped out if Illinois were to ignore the impacts from the proposed plant

The permitting of the proposed plant is in accordance with the explicit federal and state laws and rules that currently apply and govern the permitting of the plant. While different requirements may govern in other jurisdictions, those requirements are not applicable to this application or permit for the proposed plant, as the plant would be located in Illinois. Likewise, actions taken on projects proposed in other jurisdictions cannot be directly transferred to and applied to this project. This is because of the differences in the projects, their circumstances, and the legal nature of the decisions that were actually being made.

115. The Intergovernmental Panel on Climate Change (IPCC)[133] has found that the warming of the climate system is "unequivocal," that changes in atmospheric concentrations of CO_2 and other greenhouse gases alter the energy balance of the planet's climate system, that global concentrations of atmospheric CO_2 exceed the natural range over the last 650,000 years, and that continued CO_2 emissions will lead to continued warming and possibly irreversible impacts. Therefore, it recommends switching from coal in uncontrolled facilities like the one being proposed by Power Holdings, to facilities that capture and sequester their CO_2 emissions. . Other highly-respected scientific authorities have also concluded that solving the climate crisis is possible only if new coal plants control their emissions of greenhouse gases.[134]

The Illinois EPA agrees with the conclusions of the IPCC. However, the scientific findings of the IPCC, which is an international scientific body engaged in collection of information, and of other scientists, do not provide a legal basis for the permit for the proposed plant to require capture and sequestration of CO_2. Rather, as provided in the Illinois Public Utility Act, the State of Illinois has provided a substantial economic incentive for the proposed plant to capture and sequester its CO_2 or otherwise account for its CO_2 emissions,[135] which

---

[132] Kansas Department of Health and the Environment, Press Release: KDHE Electric Denies Sunflower Electric Air Quality Permit (Oct. 18, 2007).

When denying this permit, the Director of the Kansas Department of Health and the Environment stated that "it would be irresponsible to ignore emerging information about the contribution of CO2 and other greenhouse gases to climate change and the potential harm to our environment and health."[4]

[133] The Intergovernmental Panel on Climate Change (IPCC) is perhaps the leading source of research and data regarding climate change, its causes, and its impacts. The IPCC is charged with comprehensively and objectively assessing the scientific, technical and socioeconomic information relevant to human-induced climate change, its potential impacts, and options for adaptation and mitigation. To date, the IPCC has released four assessments—in 1990, 1995, 2001, and 2007, each one stating with greater confidence than the one before that the climate change situation has become increasingly dire.

The IPCC was established by the World Meteorological Organization and the United Nations Environment Programme in 1988 to comprehensively and objectively assess the scientific, technical, and socio-economic information relevant to human-induced climate change, its potential impacts, and options for adaptation and mitigation. More information about the IPCC is available at http://www.ipcc.ch/about/index.htm.

[134] The American Geophysical Union has stated that a prompt moratorium on new coal use that does not capture CO_2 and a phase-out of existing coal emissions by 2030 are critical to solving climate change. The Pew Center on Global Climate Change has also concluded that reductions in coal-based CO_2 emissions will be critical for solving the climate crisis. James Hansen of NASA has similarly noted in his testimony to Congress that "[p]hase out of coal use except where the carbon is captured and stored below ground is the primary requirement for solving global warming."

[135] As related to the proposed plant, the Illinois' Public Utilities Act (220 ILCS 5) would indirectly address the economics of the plant by addressing the situation of utilities that may purchase synthetic natural gas (SNG) from the plant. It would do this by authorizing the Illinois Commerce Commission to authorize the recovery of the cost for of SNG from the plant purchased by public utilities under long-term contracts if certain criteria are met. In addition to the cost of such gas being determined to be reasonable and prudent, one of the criteria is that the CO_2 emissions of the plant are effectively addressed either by capture and sequestration or purchase of offsets. (220 ILCS 5/9-220(h)) As this would indirectly guarantee an income stream for the proposed plant, the relevant provisions of the Public Utilities Act provide a

incentive may be essential for the financing and actual development of the proposed plant. However, Power Holding is also able to pursue the development of the project without this economic incentive. As such, Power Holdings would be able to compete fairly with other sources of natural gas, including sources of natural gas in jurisdictions that have taken no action to regulate emissions of CO_2.

116. The Illinois EPA has a legal obligation to make a searching inquiry into the potential problems posed by the GHG emissions of the proposed plant. If this were done, Illinois EPA would necessarily determine that a permit cannot be issued.

Global warming and climate change are the aggregate result of emissions on a national and global level. As such, the GHG emissions of the proposed plant would not have a significant impact on emissions or a discernable effect on climate change. In this regard, global emissions of CO_2 are currently in excess of 30 billion metric tons per year.[136] This dwarfs the CO_2 emissions of individual sources, including the emissions of the proposed plant. In addition, as will be discussed later, CO_2 and GHG are not regulated pollutants under either the federal Clean Air Act or Illinois' Environmental Protection Act. Given these circumstances, global warming and climate change do not legally provide a basis to deny the permit for the proposed plant.

117. Although the proposed plant will emit significant quantities of CO_2 and a CO_2 management strategy is contemplated in the future, CO_2 from the plant would initially be emitted to the atmosphere.

As already discussed, as CO_2 is not a currently a regulated pollutants, relevant laws and regulations currently do not require that a CO_2 management strategy be prepared at this time for the proposed plant. In addition, technologies for management of CO_2 from plants like the proposed plant are still being developed and refined. Notably, as related to geologic sequestration of CO_2, which is widely considered the most direct way to manage CO_2 emissions from new plants in Illinois using coal as their fuel/feedstock, the National Energy Technology Laboratory (NETL), an office of the United States Department of Energy, is involved with a number of pilot projects and field validation tests across the country to research, develop and refine various approaches to geologic sequestration of CO_2.[137]
GA3. Power Holdings states that the plant will use 5 million tons of coal per year. On a mass-balance basis, about a third of this will be converted into SNG that will be sold and combusted off-site, The remainder would leaving on site emissions of around 12 million tons of CO_2 per year.

Since coal is not 100 percent carbon, the conversion rate used in this comment is not correct. As indicated in other comments, a more accurate estimate of the plant's potential emissions of CO_2 is about 8 million tons per year.

---

significant incentive for the Power Holdings to address the CO_2 emissions of the proposed plant. However, this Act is nevertheless merely an incentive. It does not mandate that the proposed plant must address its CO_2 emissions, letting Power Holdings pursue development of the plant without the benefit that is potentially available under this law.

[136] Pew Center on Global Climate Change, Historical Global CO2 Emissions www://www.pewclimate.org/facts-and-figures/international/historical

[137] For geological sequestration of CO2, the current goal of NETL's CO_2 storage program for this calls for initiation of at least one large-scale demonstration of CO_2 storage (=1 million tons per year of CO_2) in a geologic formation by 2011. As reported at http://www.netl.doe.gov/technologies/carbon_seq/FAQs/project-status.html

118. The application for the proposed plant does not include data for the potential CO_2 emissions of the plant. Detailed calculations for emissions of CO_2, as well as for nitrous oxide (N_2O) and methane, which are also GHG, should have been provided. In the absence of such data, using basic assumptions and a chemical mass-balance, it is estimated that the plant's potential CO_2 emissions will be on the order of 8 million tons per year, which is a large quantity of CO_2..

As confirmed by this comment, while CO_2 emission data was not provided in the application, an order of magnitude estimate for the plant's potential emissions of CO_2 can be made based on the information in the application. As current rules do not require that CO_2 emission data be provided in permit applications, this estimate of CO_2 emissions can be used to consider the potential CO_2 emissions from the plant.

The plant should not be a major source of emissions for methane, which is the product of the plant. Direct releases of methane, as would potentially only occur during startup and malfunction of the gasification block or methanation units, would be controlled by flaring. Leaks of methane would be controlled by a leak detection and repair program, as methane leaks would be both a safety concern and a monetary loss, as they involve loss of product.

The plant also will not have significant emissions of N_20. N_20 is a form of NO_x, which is addressed by the permit. Even assuming N_20 makes up 5 percent of the plant's emissions of NO_x, the plant's potential N_20 emissions would only be about 10 tons per year.

119. The draft permit fails to satisfy requirements of the Clean Air Act because it does not reflect a "best available control technology" (BACT) analysis and would not set limits or other requirements for the plant's emissions of CO_2, N_2O, or methane. In light of the USEPA's recent proposed endangerment finding on GHG and position regarding CO_2 BACT, and the Environmental Appeal Board's recent decisions related to other GHG such as N_2O and methane, the Illinois EPA must either reissue a draft permit that would set BACT for emissions of CO_2 and other GHG for the proposed plant and hold a new public comment period, or suspend processing of the application until USEPA completes its reconsideration and rulemaking for GHG emissions.

CO_2 and other GHG are not pollutants that are currently regulated under the federal PSD program, and therefore are not subject to the requirement for BACT under the PSD program. This has recently been clarified in a number of formal actions by USEPA, including the USEPA's Environmental Appeals Board (EAB).[138] It is also indirectly acknowledged by this comment as it requests that the Illinois EPA defer action on the application until USEPA completes action to actually regulates emissions of GHG. The Illinois EPA was legally bound when processing the permit application for the proposed plant to follow USEPA's current guidance with respect to the pollutants that qualify as regulated pollutants under the PSD program.[139] In addition, given the timing of rulemaking by USEPA under federal law and the likelihood of legal challenges that might

[138] The only judicial case addressing the GHG BACT issue raised in these comments was a decision by a state trial court in Georgia in Friends of the Chattahoochee, Inc., v. Couch ("Longleaf"), Docket No. 2008CV146398, Superior Court of Fulton County, Georgia (June 30, 2008). While the trial court ruled that CO2 is "subject to regulation" under the Clean Air Act, that decision was reversed by the Georgia Court of Appeals on July 7, 2009 in an opinion that thoroughly recounted the legal and administrative history and found the Johnson Memorandum to be a dispositive USEPA interpretation. Furthermore, the Plaintiffs' Petition for Certiorari review of the Court of Appeals' reversal was summarily denied by the Georgia Supreme Court on September 30, 2009. Therefore, the actual judicial decision on this issue in Georgia confirmed that the Johnson Memorandum was controlling federal policy.

[139] **Section 9.1(a) of Illinois' Environmental Protection Act also specifically states that the PSD program be developed and implemented in Illinois "…to avoid duplicative, overlapping or conflicting State and federal regulatory systems."**

delay the effectiveness of rules that are not adopted, it is not appropriate to delay action on the application for the proposed plant pending completion of rulemaking by USEPA.

The Johnson Memorandum

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.[140] Notice of this determination was subsequently provided by a notice in the Federal Register.[141] 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 the Johnson 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 for reconsideration by USEPA of the Johnson Memorandum, she did not stay the effect or validity of the memorandum.[142] In addition, no further action has been taken by USEPA to date to formally reconsider the Johnson Memorandum.

Section 821 Argument.

The interpretation put forth in the Johnson 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

---

[140] 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* (Johnson Memorandum).

[141] Notice of the Johnson 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).

[142] As is discussed below, 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.

data for CO_2.[143] Congress did not specify that the provisions of the Clean Air Act for PSD were to also be applicable.

Delaware SIP Argument.
In the Johnson Memorandum, USEPA also responded to the contention that USEPA's approval of a Delaware SIP addressing CO2 emissions was tantamount to USEPA regulation of CO2 under the CAA. The Johnson Memorandum recognizes the difference 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.[144] 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. There is an obvious difference in the nature of SIP revisions and emission standards adopted by USEPA and coincidental action by USEPA in approving a SIP submittal for a particular state is insufficient to create a "regulated air pollutant" as a matter of national law.[145]

USEPA's Proposed Endangerment Finding
In addition, the USEPA, under the leadership of Administrator Jackson, has begun a separate legal proceeding whereby emissions of CO_2 would be regulated under the Clean Air Act. It has done this by formally proposing to make 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.[146] In the Federal Register notice for the Proposed Endangerment Finding, USEPA also explained that even an actual Endangerment Finding would not in itself trigger PSD permitting requirements. In addition, the USEPA affirmed the confirmed the Johnson Memorandum, indicating that

---

[143] 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.

[144] 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 PSD.

[145] **Also, as stated in 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 GHG emissions. 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.[145] 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.)**

[146] The USEPA's *Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) the Clean Air Act* was published in the Federal Register on April 24, 2009 (74 FR 18886).

even though it is engaged in reconsideration of the Johnson Memorandum, the Memorandum still represents currently applicable USEPA policy.[147]

Louisville Gas & Electric Order (Trimble County Order)
USEPA also recently spoke to the issue whether GHG are regulated pollutants in a proceeding concerning the permitting of Louisville Gas and Electric Company's Trimble County power plant[148] In its Order in that proceeding , USEPA specifically denied the petitioners claim that USEPA must object to the permit because the permit failed to include requirements addressing emissions of CO_2 and other GHGs, including a BACT determination for emissions of CO_2. This confirms that GHG emissions are not currently regulated under the Clean Air Act.[149]

The Deseret Power Decision
Various arguments relating to the premise of this comment, i.e., that CO_2 is a regulated 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,[150] the EAB rejected the petitioner'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

---

[147] **As explained in Footnote** 29 of the Proposed Endangerment Finding, "At this time, a final positive endangerment finding would not make the air pollutant found to cause or contribute to air pollution that endangers a regulated pollutant under the PSD program. See memorandum entitled "EPA's Interpretation of Regulations that Determine Pollutants Covered By Federal Prevention of Significant Deterioration (PSD) Permit Program" (Dec. 18, 2008).

USEPA is reconsidering this memorandum and will be seeking public comment on the issues raised in it. That proceeding, not this rulemaking, would be the appropriate venue for submitting comments on the issue of whether a final, positive endangerment finding under section 202(a) of the Clean Air Act should trigger the PSD program, and the implications of the definition of air pollutant in that endangerment finding on the PSD program."

[148] **Order Responding to Issues Raised in April 28, 2008 and March 2, 2006 Petitions, and Denying in Part and Granting in Part Requests for Objection to Permit, Petition No. IV-2008-3, August 12, 2009, In the Matter of: Louisville Gas and Electric Company Trimble County, Kentucky Title V/PSD Air Quality Permit, (Trimble County))**

[149] **On page 16 of the Trimble County Order, USEPA states "Petitioners are essentially arguing that at the time KDAQ issued the permit, the federal PSD program required application of BACT requirements to CO_2 emissions and KDAQ erred by not including such limits. However, this argument fails because the EAB specifically found that there was no established standard regarding whether CO_2 was 'subject to regulation' under the federal PSD program and that the position urged by Petitioners – PSD regulation of CO_2 was required given existing monitoring and reporting requirements – is not clearly dictated by the language of the CAA or EPA regulations. Deseret Power at 63. Accordingly, Petitioners have not established that KDAQ's failure to require CO_2 emissions limits in this permit was incorrect because they did not show that KDAQ implemented the PSD program in a manner less stringent than the existing federal PSD program. [Footnote 17]"**

In Footnote 17, the USEPA further explains "The position taken in KDAQ's permitting decision rests on the interplay of its SIP and the federal PSD program, and that decision is consistent with the EPA's present position regarding which pollutants are subject to federal PSD permitting requirements."

While acknowledging Administrator Johnson's February 17, 2009 letter to David Bookbinder granting reconsideration of the Johnson Memorandum, on page 16 of the Order, USEPA states "In granting reconsideration, Administrator Jackson announced the intent to conduct a rulemaking to take public comments on the issues raised in the memo, but she did not stay the effectiveness of the Johnson memo pending reconsideration."

In addition, on page 15 of the Trimble County Order, USEPA took note of the EAB's Decisions with respect to Deseret and Christian County. The USEPA explains " ... regulations in the CAA Acid Rain program that require monitoring of some sources did not make CO_2 subject to PSD regulation." "Moreover, at that time, no federal permitting authorities had actually imposed PSD requirements for CO_2; in fact, no federal PSD permit has since been issued by USEPA that includes CO_2 limits."

[150] **PSD Appeal No. 07-03, Order Denying Review in Part and Remanding in Part, issued November 13, 2008]**

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 the Johnson Memorandum on December 18, 2008, as previously discussed, was directly responsive to the EAB's ruling in the Deseret Case.

Other EAB Decisions following Deseret Power

In two other EAB decisions following the November 13, 2008 Deseret Power decision, the EAB has remanded the permit to either allow the permitting authority to address the USEPA GHG BACT policy questions raised in Deseret Power (Northern Michigan University Ripley Heating Plant, PSD Appeal No. 08-02, Feb. 18, 2009) or allowed the permitting authority to voluntarily withdraw the GHG BACT portion of its permit record to address the Deseret Power questions on the record (Desert Rock Energy Company, PSD Appeal No. 08-03, 08-04,08-05 & 08-06). This was necessary because both these cases involved permitting actions that were taken before USEPA's interpretation was questioned by the EAB's decision in the Deseret Power and before the Johnson Memorandum firmly established EPA's interpretation. The EAB has not ruled on any PSD permit appeal questioning the status of GHG where the record demonstrates consistency with fully established and documented USEPA interpretation, as has since been provided in the Johnson Memorandum and confirmed by current Administrator Jackson.

USEPA's Proposed Rules to Set Applicability Thresholds for GHG in the PSD Program

On September 30, 2009, in a very recent administrative action,[151] USEPA has made it clear that GHGs are not currently regulated under the Clean Air Act and that it is taking steps to carefully approach possible future applicability of the PSD rules to GHG. On that date, USEPA announced its intention to propose rules establishing PSD applicability thresholds for GHGs. USEPA took this action because it expects to adopt regulations under the Clean Air Act to control GHG emissions from light duty motor vehicles, pursuant to a rulemaking proposal signed on September 15, 2009. USEPA recognizes that, absent any intervening changes to federal law by Congress, completion of that rulemaking related to motor vehicles would also act to trigger Clean Air Act permitting requirements under the PSD program for GHG emissions.[152] Conversely, absent completion of that rulemaking related to emissions of GHG from motor vehicles or other comparable rulemaking that actually controls emissions of GHG, emissions of GHG regulated under the Clean Air Act.

Conclusion

USEPA's proposed endangerment finding, proposed rulemaking for GHG emissions from certain motor vehicles, and proposal to establish thresholds for GHG PSD applicability all indicate the USEPA's willingness to proceed to regulate GHG's under the Clean Air Act in an orderly fashion in the future. At the same time, they show that GHG are not currently regulated under the Clean Air Act. Moreover, in conjunction with legislation to address emissions of GHG, Congress is also considering whether it should expressly prohibit

[151] USEPA, Announcement of Proposed Rule, Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, Docket No. EPA-HQ-OAR-2009-0517

[152] In the preamble to this proposal, USEPA states "This proposal is necessary because EPA expects soon to promulgate regulations under the CAA to control GHG emissions from light-duty motor vehicles and, as a result, trigger PSD and title V applicability requirements for GHG emissions." Pre-publication Proposal, p. 15.

regulation of GHG emissions under the PSD provisions of the Clean Air Act.[153] In this regard, USEPA Administrator Jackson stated in her confirmation hearings that it would be preferable that GHG be regulated under a new comprehensive climate bill, rather than under the Clean Air Act. In any event, until appropriate regulatory action is taken by USEPA or national legislation is adopted, the Illinois EPA is bound to follow existing law and established USEPA policy on the status of GHG under the federal PSD program.

120. Current USEPA Administrator Lisa Jackson has warned that "PSD permitting authorities should not assume that the Johnson Memorandum is the final word on the appropriate interpretation of Clean Air Act requirements." Instead, USEPA intends to begin notice-and-comment rule-making in order to establish USEPA's official interpretation in the "near future."

While the Johnson memorandum may not be final interpretation of the term "regulated pollutant" under the Clean Air Act, it is nevertheless the USEPA current interpretation of this term. As such, the Illinois EPA must carry out the permitting of the proposed plant based on this interpretation.

121. The Johnson Memorandum will almost certainly be reversed by the courts or withdrawn by the USEPA under the leadership of Administrator Jackson. The Illinois EPA should not and cannot rely upon this Memorandum.

As explained above, the Illinois EPA must carry out the permitting of the proposed plant based on the USEPA's current interpretation of the term "regulated pollutant," as is set forth in the Johnson memorandum. As a legal matter, the Illinois EPA cannot legally rely on predictions or assumptions about future actions that would change this interpretation.

122. With its release of a draft endangerment finding for CO_2 and other GHG, which will trigger regulation of GHG emissions from motor vehicles under the Clean Air Act,[154] USEPA has now officially declared that CO_2 and other GHG are air pollutants that "may be reasonably anticipated to endanger public health and welfare" for purposes of regulation under the Clean Air Act. This irrefutably shows that GHG emissions are subject to regulation under the Clean Air Act.

This action by USEPA cited by this comment did not result in CO_2 or other GHG becoming regulated pollutants under the Clean Air Act. Rather, the release of a draft endangerment finding for GHG is another action by USEPA that confirms that GHG are not yet regulated under the Clean Air Act. The issuance of an endangerment finding would not be needed if emissions of GHG were already being regulated. In addition, the USEPA has only proposed to make an endangerment finding, publishing a draft of the finding that it would propose to make, accompanied by its rationale for such finding and a discussion of supporting documentation. The USEPA has not yet actually made an endangerment finding, which will only occur if and when a final endangerment finding is issued, subject to appropriate resolution of any legal challenges that may be made to such finding. Second, and perhaps more importantly, the proposed endangerment finding does not constitute regulation of GHG under the Clean Air Act. Rather, it merely reflects a formal finding by GHG that GHG are appropriate for regulation under the Clean Air Act. Separate

---

[153] *See* the proposed American Clean Energy and Security Act of 2009 (Waxman-Markey Bill) and the proposed Clean Energy Jobs And American Power Act (Boxer-Kerry Bill).

[154] USEPA, Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, ("Endangerment finding"), 74 FR 18,886 (April 24, 2009) (also available at http://epa.gov/climatechange/endangerment/downloads/GHGEndangermentProposal.pdf).

rulemaking action by USEPA is needed to adopt rules under the Clean Air Act that actually have requirements that control or "regulate" emissions of GHG from certain categories of sources.[155]

123. Contrary to the Clean Air Act, the draft permit would not set BACT for the emissions of GHG from the proposed plant. Section 165(a)(4) of the Clean Air Act requires that BACT be set for any major new or modified source of GHG emissions because GHG are subject to regulation under the Clean Air Act. (See also 40 CFR 52.21(b)(50).) A PSD permit for a source that emits significant quantities of a pollutant "subject to regulation" under the Clean Air Act must include an emissions limit based on the BACT. for that pollutant pursuant to Section 165(a)(4) of the Clean Air Act. CO_2 is currently regulated under the Act because various statutory and regulatory provisions require monitoring, reporting, and control of CO2 emissions. Emissions of GHG are also "subject to regulation" under the Act. The USEPA recently proposed to make an endangerment finding for emissions of GHG that will trigger regulation of GHG from motor vehicles under the Clean Air Act. The permit for the proposed plant must therefore set BACT for emissions of CO_2.

As previously explained, CO_2 and other GHG are not pollutants that are currently regulated under the federal PSD program, and therefore are not subject to the requirement for BACT under the PSD program. This has recently been clarified and confirmed in a number of formal actions by USEPA that consistently demonstrate that GHG are not currently regulated pollutants under the Clean Air Act.

124. GHG should be considered regulated pollutants under the Clean Air Act because a state court in Georgia recently held in a proceeding concerning the proposed Longleaf power plant that any argument that GHG are not subject to regulation under the Clean Air Act is "untenable."[156]

The cited court decision in Georgia, as it was not made either in federal court or an Illinois court, is neither binding nor instructive for how the federal PSD program should be applied to the proposed plant. As previous explained, GHG are currently not considered regulated pollutants for purposed of the federal PSD program.

Moreover, in July of 2009, an Appeals Court in Georgia overturned the decision of the trial court. Subsequently, on September 30, 2009, the Georgia Supreme Court refused to further consider this matter, denying a Petition for *Certiorari* in the matter. Thus, the controlling law in Georgia based on Longleaf case is the Court of Appeals decision, that is, GHG are not currently regulated under the Clean Air Act. In this regard, an Appeals Court in Georgia apparently found that the trial court's decision was untenable.

125. Global warming has long been recognized to be a threat to public health, welfare, and the environment.[157] As the USEPA recently found in a proposed endangerment finding for GHG:

---

[155] In anticipation of completion of such rulemaking controlling emissions of CO_2 from certain motor vehicles, USEPA has proposed revisions to the PSD program to appropriately address emissions of CO_2 and GHG. The proposed revisions are intended to set appropriate applicability criteria for applicability of the PSD program to proposed projects based on their potential GHG emissions or the increase in GHG emissions accompanying a proposed modification.

[156] Friends of the Chattahoochee, Inc. v. Couch, Docket No. 2008CV146398, slip. op. at 7 (Ga. Sup. Ct. June 30, 2008) .

The reports prepared by the IPCC authoritatively document the adverse environmental and socioeconomic impacts of global warming at local, regional, national, and global scales, and the primary role of the burning of fossil fuels in causing global warming. The evidence in the IPCC reports conclusively shows that anthropogenic emissions of greenhouse gases endanger public health, welfare, and the environment. The United States government recently officially adopted this conclusion.

The evidence points ineluctably to the conclusion that climate change is upon us as a result of GHG emissions, that climatic changes are already occurring that harm our health and welfare, and that the effects will only worsen over time in the absence of regulatory action. The effects of climate change on public health include sickness and death…The effects on welfare embrace every category of effect described in the Clean Air Act's definition of "welfare" and, more broadly, virtually every facet of the living world around us. . . . In both magnitude and probability, climate change is an enormous problem.

The effects of climate change include] heat waves, more wildfires, degraded air quality, more heavy downpours and flooding, increased drought, greater sea level rise, more intense storms, harm to water resources, harm to agriculture, and harm to wildlife and ecosystems. [158]

While global warming will have a significant impact on the human environment, Illinois EPA did not consider these effects. Consideration of the direct and collateral effects from construction of the proposed plant must be analyzed before any permit decision is made. Moreover, limits on the GHG emissions from the proposed plant must be included in the permit.

The Illinois EPA agrees that global warming and climate change are critical issues facing mankind. However, this does not legally justify disregarding current laws and rules during permitting of the proposed plant. Moreover, the appropriate response to these issues is concerted and coordinated national action to directly address these issues, as is currently being considered by Congress, as well as coordinated action internationally. It is not piece-meal action on permit applications for individual projects, especially when those actions have no effect on existing sources whose operation and GHG emissions continue unabated. Finally, as legal matter, until such time as Congress, the USEPA or the Illinois legislature take such action requiring control of emissions of CO_2 or GHG, the Illinois EPA does not have the authority to address GHG emissions as regulated pollutants in its implementation of the PSD program.

126. One option that must be considered to reduce the GHG emissions from the proposed plant, which must be considered as BACT, is CO_2 capture and sequestration (CCS).

As already discussed, under the current regulatory framework, emissions of GHG, including emissions of CO_2, are not subject to BACT pursuant to the PSD program. As such, CCS is not relevant to the BACT analysis for the proposed plant. In addition, as also already discussed, for the proposed plant, the application of CCS by is directly addressed under state law, by the Public Utility Act, separately from the construction permit that has been issued for the plant.

14. Pursuant to the Clean Air Act, the Illinois EPA must consider all emission control options when establishing BACT limits for the proposed plant. CCS is one such option that must be considered. Note that my comments regarding CCS are intended to inform the Illinois EPA in carrying out its legal obligation and should not be considered as supporting CCS as a solution to the climate change problems posed by the construction of a coal-based plant. CCS should be considered a last resort, as there are abundant non-coal alternatives that avoid the environmental impact of coal mining and coal waste disposal while sustaining jobs and the economy. These alternatives are sufficient to satisfy any energy needs without turning to coal—with or without

[158] USEPA Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act; Proposed Rule, 74 FR 18886, 18904 (April 24, 2009).

CCS. Notwithstanding the last-resort nature of CCS, Illinois EPA is obligated to consider it and Illinois EPA has not done so.

As previously discussed, a BACT determination for emissions of GHG from the proposed plant is not legally required or authorized. As such, consideration of CCS is also not required as it would be a control measure for emissions of CO_2.

As this comment suggests that there are alternatives to the proposed plant, even if it uses CCS, the suggested alternatives are theoretical in nature. That is, the comment does not explain what would occur to make the alternative projects actually take place, who would carry out those alternative projects, and how they would be financed, much less demonstrate that they "…are sufficient to satisfy any energy needs without turning to coal…" As such, they are not realistic alternatives to the proposed plant, which if developed would provide and support the economy of Southern Illinois and Illinois generally.

127. On its website,[159] Power Holdings states that the proposed plant would separate "…about 90% of the CO_2 in the Syngas stream for possible use."[11] In fact, Power Holdings intends to take advantage of a recent Illinois law that addresses new "clean coal SNG facilities," i.e., 220 ILCS 5/9-220(h), as amended by Ill. Pub. Act 095-1027.[160] To qualify for the benefits of this law, the SNG manufacturing process must sequester at least 90 percent of the total carbon emissions. 20 ILCS 3855/1-10.12. Moreover, the proposed plant is already being designed with a Rectisol system to separate CO_2 from the raw syngas. The sequestration of CO_2 must be considered in the BACT analysis, and complete capture must be considered.

This comment does not demonstrate that sequestration of CO_2 had to be considered in a determination of BACT made for the proposed plant. As observed by this comment, the State of Illinois has provided a substantial economic incentive for the proposed plant to capture and sequester its CO_2 or otherwise account for its CO_2 emissions,[161] through recent amendments to Illinois' Public Utility Act. This incentive may be very beneficial for the financing and actual development of the proposed plant. However, this creation of an incentive for CCS under Illinois' Public Utilities Act is not the same as regulation of CO_2 under Illinois' Environmental Protection Act, which has not occurred. Moreover, the Public Utility Act does not mandate that Power Holdings must avail itself of this incentive. Power Holdings is also able to proceed with the project without this economic incentive, fairly competing with other sources of natural gas, including sources of natural gas in jurisdictions that have taken no action to regulate emissions of CO_2. As such it was not appropriate under either applicable state or federal law, as already discussed, for the Illinois EPA to consider sequestration as a possible component of BACT for the plant or to mandate in the permit for the proposed plant that CO_2 must be sequestered.

---

[159] See http://www.powerholdingsllc.com.

[160] According to Section 1.5(8) of Illinois Public Act 95-1027, "The State should encourage the use of advanced clean coal technologies that capture and sequester carbon dioxide emissions to advance environmental protection goals and to advance the viability of coal and coal-derived fuels in a carbon constrained economy."

[161] As related to sequestration of CO_2 by facilities such as the proposed plant, Illinois' Public Utilities Act also provides that "If, in any year, the owner of the facility fails to demonstrate that the SNG facility captured and sequestered at least 90% of the total carbon dioxide emissions that the facility would otherwise emit or that sequestration of emissions from prior years has failed, resulting in the release of carbon dioxide into the atmosphere, then the owner of the facility must offset excess emissions. Any such carbon dioxide offsets must be permanent, additional, verifiable, real, located within the State of Illinois, and legally and practicably enforceable." (220 ILCS 5/9-220(h).)

The fact that the proposed plant would be built to separate or recover the CO_2 from the syngas does not change this situation. It merely confirms that the proposed plant would be developed with the first step for CCS in place, i.e., capture of CO_2. It does not answer whether Power Holdings would decide to seek the financial incentive that is available under the Illinois Utility Act and sequester CO_2 from the plant. It also does not answer where or how this CO_2 might be sequestered. In this regard, captured CO2 might be sequestered at or near the plant. The CO_2 might also be transported by pipeline and sequestered some distance from the plant. If the CO_2 is transported by pipeline, the CO_2 might also be sequestered in conjunction with productive use of the CO_2 for enhanced oil recovery in existing oil field in southern Illinois.

128. Despite Power Holdings' publicly announced plans to capture and sequester 90 percent of the CO_2 produced by the proposed plant, the application for the plant does not include a proposal or plan for CCS.

As previously discussed, a BACT determination is not legally required or authorized for emissions of CO_2 from the proposed plant. As such, a proposal or plan for CCS was not required to be part of the application. In addition, Power Holdings' plans for CCS would be subject to separate review under the provisions of Illinois' Public Utilities Act.[162] As also discussed, the sequestration wells for CCS would also be subject to review under as part of permitting under the federal Underground Injection Control Program, 40 CFR Part 144.

Moreover, Power Holdings has not stated that it plans to sequester 90 percent of the CO_2 produced by the proposed plant. Rather, it has stated that the CO_2 would be removed from the raw syngas produced by the plant, with about 90 percent of this recovered CO_2 available for <u>possible use</u>.

129. CCS is a way to reduce the emissions from the proposed plant and must therefore be considered as an alternative to the project, pursuant to Section 165(a)(2) of the Clean Air Act, as well as BACT, pursuant to Section 165(a)(4) of the Clean Air Act.

The Illinois EPA has considered CCS as an "alternative" for this project as requested by this comment. Given that CO_2 is not currently a regulated pollutant for purposes of the federal PSD program, it would not be appropriate to require an alternative to or alteration of the proposed plant whose principal justification, if not sole justification, would be to control emissions of CO_2. In addition, under our social and economic system, which is governed by the "rule-of-law, certain standards of reasonableness and fairness exist that must be met before imposing additional requirements on a proposed project using discretionary authority rather than direct authority as established by law or rule. At this time, a requirement that the plant use CCS would not meet such standards. This is because of the potential cost and complexity of geological sequestration of CO_2, which will add significantly to the cost and challenges of developing the proposed plant. Only a general nexus can be made between the CO_2 emissions of the proposed plant and global warming and climate change. As a national program for control of CO_2 emissions has not yet been adopted, it cannot be assured that CCS would be required of other similar projects located outside of Illinois as such a requirement would be subject to the judgment and authority of the permitting authorities in those jurisdictions. As a state program for control for CO2

---

[162] In addition to addressing CCS, to qualify for the incentive under Section 9-220(h) of the Illinois Public Utilities Act, it must be determined that "The cost for the SNG is reasonable and prudent." This necessarily would require an evaluation by the Illinois Commerce Commission of the costs associated of CCS.

emissions has not yet been adopted, Power Holdings has not been provided with due notice that CCS would be required at the proposed plant.

Moreover, as the proposed plant is directly addressed by the Illinois Public Utilities Act, that Act should be considered to set Illinois' policy with respect to use of CCS by the plant. That is, the use of CCS should be encouraged by the State of Illinois, as is occurring as that Act would provide a significant incentive for the proposed plant to use CCS. However, use of CCS should not be mandated at this time. This is a sound approach to the proposed plant until a regulatory program is adopted that would address the plant's CO_2 emissions.[163]

130. Any CO_2 sequestration for the proposed plant must be sited and carried out in ways to ensure that the CO_2 stays sequestered, is geologically safe, and does not impact drinking water supplies. There are geologic faults located near the proposed plant site. Highly faulted storage basins are poor candidates for CO_2 storage.[164] To the extent that the Illinois EPA considers CCS and considers sequestration on or near the project site, the Illinois EPA should seek an official opinion from the Director of the Illinois State Geological Survey's Energy and Earth Resources Center regarding the presence of fault and how seismic risk could affect the suitability of the area for CO_2 sequestration.[165]

The concerns about sequestration of CO_2 posed by this comment would be addressed as part of separate permitting of CO_2 sequestration wells under the federal Underground Injection Control (UIC) program, 40 CFR Part 144. The USEPA is currently engaged in rulemaking to revise the UIC Program to specifically address the appropriate design of injection wells used for sequestration of CO_2.[166] **As USEPA is currently revising the UIC Program to specifically address sequestration of CO_2 and Power Holdings has not submitted a plan for sequestration of CO_2 emissions of the proposed plant, much less an application for a UIC permit, it is not appropriate to solicit an opinion from the Director of the Energy and Earth Resources Center at the ISGS concerning CO_2 sequestration for the plant. The ISGS could only speculate on the nature of such sequestration, providing cautions for or identifying possible concerns for the development of CO_2 sequestration in the area of the proposed plant.**[167]

131. Options other than CCS exist to reduce GHG emissions from the proposed plant that could be included in an analysis and determination of BACT, including: increased efficiency; controls

---

[163] **The future regulatory program for CO_2 will almost certainly comprehensively address CO_2 emissions, addressing not only significant new sources of CO_2 like the proposed plant, but also significant existing CO_2 sources. In addition, the future regulatory program for CO_2 may be more flexible and cost-effective in its approach to control of CO_2. Rather than simply mandating use of CCS by certain plants, such program may also encompass sequestration of CO_2 in conjunction with enhanced oil recovery and acquisition of CO_2 credits or offsets as a means to mitigate CO_2 emissions. It might also approach the CO_2 emissions of certain categories of sources with a market-based cap-and-trade system. In this regard, it is also significant that if less than 90 percent of the plant's CO_2 emissions are sequestered, the Illinois Public Utilities Act accommodates use of CO_2 offsets to account for the deficit.**

[164] See IPCC Report on Carbon Capture and Storage, Chapter 5, available at http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCSfinal/IPCCSpecialReportonCarbondioxideCaptureandStorage.htm.

[165] The Illinois EPA should also seek an official opinion from the ISGS regarding the potential for accidental syngas releases from the plant.

[166] **Refer to Proposed Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells, 73 FR 43,491 (July 25, 2008).**

[167] **As with CO_2 sequestration, in the absence of detailed design information for the plant as related to seismic impacts, the ISGS could merely observe that the plant is located near certain faults and should be appropriately designed to address the potential seismic risk posed by those faults.**

options and work practice standards; and co-firing the combustion units at the plant with lower carbon fuels, including natural gas or biomass.

As previously discussed, under the current regulatory framework, emissions of GHG, including emissions of CO_2, are not subject to BACT pursuant to the PSD program. As such, control options to reduce emissions of GHG are not relevant to the BACT analysis for the proposed plant. In addition, other than broadly mentioning certain control options other than CCS, this comment does not include any further discussion or supporting information explaining how those options should be evaluated to address their potential for reducing emissions of the proposed plant, much less show that those options are feasible or practical. In particular, this comment does not explain how "increased efficiency" should be addressed or what sort of controls and work practices should be addressed. It also does not explain the difference in emissions of GHG from using SNG (natural gas) from the plant as fuel in combustion units at the plants, emission as compared to using cleaned syngas. It also does not explain whether use of biomass fuels should be considered preferable to use of natural gas. This supporting information would be needed to proceed as requested by this comment as it suggests that the BACT analysis for the plant should go beyond the established scope of such analyses to address pollutants that are not currently regulated.

132. Lifecycle analysis shows that coal-to-gas plants, like the proposed plant, will emit more than twice as much CO_2 as a conventional natural gas combined cycle power plant.[168] Additionally, the GHG emissions from the proposed plant will include N_2O and methane.

This comment is not relevant to the proposed plant as the proposed plant would produce substitute natural gas (SNG), not electricity. In this regard, the supporting material submitted with this comment addresses the emissions of CO_2 or "carbon footprint" associated with generation of electricity using various fuels. It does not address the carbon footprint associated with use of natural gas from different sources, which would entail a different and more complex analysis.[169]

Incidentally, power plants burning natural gas and coal also emit methane and N_2O.

133. If the proposed plant does not have CCS, the plant will have more GHG-emissions when considered with lifecycle analysis on than other sources of natural gas, such as domestic produced natural gas or liquefied natural gas imported from overseas.

As already discussed, under the current regulatory framework, GHG and not regulated pollutants for purposes of PSD and are not subject to BACT pursuant to the PSD program. In addition, the PSD does not require a comprehensive, "lifecycle analysis" be conducted in conjunction with a determination of BACT, which focused on the particular proposed project and the control technology that might be used to reduce its emissions.

---

[168]The emissions of CO_2 per MWh of output are 1,250, 1,600, 2,270 and 3,550 pounds for use of natural gas, imported liquefied natural gas, coal, and synthetic natural gas, respectively, as reported by Paulina Jaramilo and others in *Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, And SNG for Electricity Generation,* Environmental Science and Technology, 41.17, page 6203, (2007)

[169] Lifecycle analysis for the use of natural gas from different sources would be more complicated because the analysis could not simply assume that the different "types" of natural gas were all used to generate electricity. An assessment would be needed for the amount of gas used for different purposes. Potential consideration would also be appropriate for the consequences of use of natural gas in lieu of other potential sources of energy. For example, does the availability of natural gas displace use electricity or wood and what was its carbon footprint?

At the same time, as implied by this comment, the proposed plant would be more "energy intensive" than current sources of natural gas with accompanying greater emissions of CO_2. This is because a significant amount of energy is required to convert coal into synthetic natural gas (SNG).[170] However, this does not show that the plant would be more energy intensive in the future, when natural gas is being extracted from geological reserves of natural gas that are more difficult recover than the reserves that are currently being used. It also does not show that the plant would not be beneficial as it helps to maintain reliable and affordable supplies of natural gas going into the future. However, the comment does confirm the importance of continuing to improve energy efficiency and conserve resources, which is important from both the environmental and economic perspective.

134. USEPA's comments on a draft Environmental Impact Statement (EIS) for the then-proposed White Pine Energy Station in Nevada directed the federal Bureau of Land Management (BLM) to "…discuss carbon capture and sequestration and other means of capturing and storing carbon dioxide as a component of the proposed alternatives."[171] The USEPA's determination that it is appropriate for the BLM to consider CCS and other means of capture and storage $CO_2$for the White Pine project is a reasonable indication that CCS and other means of addressing CO_2 should also be considered in the BACT process for the PSD permit for the proposed plant.

The action by USEPA cited in this comment does not demonstrate that CCS must be considered as part of the processing of the PSD permit for the proposed plant. The context of the USEPA's comments related to the proposed White Pine Energy Station[172] differs significantly from that of the proposed plant. Simply stated, what is appropriate for the content of an Environmental Impact Statement (EIS) is not necessarily transferable to the processing of the PSD permit application. This is because EIS are prepared to evaluate the environmental impacts of certain potentially significant actions by the federal government, as required under the federal National Environmental Policy Act (NEPA), not the Clean Air Act. In the case of White Pine, the BLM was evaluating with the EIS process whether it should allow public land, which it managed, to be used for the development of the proposed White Pine Station. However, the proposed plant would not be developed on land managed by the BLM.

Incidentally, the document provided with this comment was not the USEPA's comments to the BLM during the development of the EIS for the proposed White Pine Station. As clearly stated by USEPA in the introduction to those comments to the BLM, those comments were submitted pursuant to NEPA. The document provided with this comments was prepared by the State of Nevada, Nevada Division of Environmental Protection, Bureau of Air Pollution Control, in February 2009 and explained why it had determined that GHG were not regulated pollutants under the Clean Air Act. As such, the document provided with this comment is an example of another state permitting authority under the Clean Air Act that has formally recognized that GHG are not presently regulated under the Clean Air Act.

---

[170] As the proposed plant is designed to be "energy self-sufficient," this energy of conversion would be supplied by the feedstock. Effectively, the SNG from the plant contains less energy than the energy in the feedstock, with the difference being the energy consumed in the conversion process. The plant would only import incidental amounts of electricity off the grid, notably during startups.

[171] Nevada Division of Environmental Protection, *Determination of Greenhouse Gas Regulation Pursuant to the Clean Air Act For The White Pine Energy Station*, February 2009.

[172] Letter, June 22, 2007 , Nova Blazej, Manager Environmental Review Office, USEPA, Region 9, to Jeffrey Weeks, BLM, Ely Field Office, Subject: Draft Environmental Impact Statement for White Pine Energy Station project, Nevada [CEQ# 20070151]

135. Recent applications for similar projects, such as the proposed Cash Creek Generating Station in Kentucky, include CO_2 BACT analyses that consider CSS as a control option. [173] While the Cash Creek CO_2 BACT analysis is flawed, as it does not consider process efficiency and use of biomass, it shows that a BACT analysis should include CCS.

The submittals referred to by this comment do not demonstrate that CCS must be considered in the BACT analysis for the proposed plant, given the nature of those submittals. In particular, the CO_2 BACT analysis that is part of the application for the proposed Cash Creek Generating Station was a "voluntary" submittal, as clearly stated on page 4 of the analysis. [174] As generally explained by the Kentucky Department of Air Quality (KDAQ) in a proceeding concerning Louisville Gas And Electric's Trimble County Station, the state PSD program in Kentucky, as implemented by KDAQ can be no more stringent that the federal PSD program and does not currently require BACT analyses for CO_2.[175] On page 16 of its Order in that case,[176] the USEPA confirmed the position of the KDAQ on this point.[177] In addition, as this comment suggests that the CO_2 BACT analysis for the proposed Cash Creek Generating Station are deficient, it should not be considered to be a model or guide for the appropriate scope and content of a BACT analysis for CO_2 emissions from a coal gasification plant.[178, 179]

---

[173] Application, Cash Creek Generating Station, Addendum 2: CO2 BACT Analysis – December 2008

[174] Also refer to page 39 of the Kentucky Division for Air Quality's Draft Permit Statement Of Basis for the Cash Creek Generating Station.

"The applicant provided a BACT analysis for CO_2 with respect to the combustion turbines, acid gas recovery vent, thermal oxidizer, flare, aspirator vent, auxiliary boiler, methanation heater, fire pump and emergency generator on December 15, 2008. That BACT analysis provided CO_2 control efficiencies ranging from 32.93 to 100 percent for each of these emission units.

Pursuant to KRS 224.10-100(26) and KRS 13A.130, the Division is precluded from regulating CO_2. Therefore, the Division notes that the applicant did provide a CO_2 BACT analysis that is available for review and is part of the permitting process record."

[175] Section 9.1(a) of Illinois' Environmental Protection Act, which addresses the PSD program as well as certain other federal regulations pursuant to the Clean Air, establishes a similar restriction on the stringency of the implementation of the PSD program in Illinois, "It is the purpose of this Section to avoid the existence of duplicative, overlapping or conflicting State and federal regulatory systems.

[176] Order Responding to Issues Raised in April 28, 2008 and March 2, 2006 Petitions, and Denying in Part and Granting in Part Requests for Objection to Permit, Petition No. IV-2008-3, August 12, 2009, In the Matter of: Louisville Gas and Electric Company Trimble County, Kentucky Title V/PSD Air Quality Permit.

[177] **In addition, the USEPA's Order in Trimble County specifically referenced and took into consideration the EAB's Decisions with respect to Deseret and Christian County. On page 15, the Order states " ... regulations in the CAA Acid Rain program that require monitoring of some sources did not make CO_2 subject to PSD regulation." "Moreover, at that time, no federal permitting authorities had actually imposed PSD requirements for CO_2; in fact, no federal PSD permit has since been issued that includes CO_2 limits."**

While acknowledging Administrator Jackson's February 17, 2009 letter to David Bookbinder granting reconsideration of the Johnson Memorandum, the Order on page 16 again confirms the Johnson Memorandum stating "In granting reconsideration, Administrator Jackson announced the intent to conduct a rulemaking to take public comments on the issues raised in the memo, but she did not stay the effectiveness of the Johnson memo pending reconsideration."

[178] The performance levels for CO_2 emissions provided in the BACT analysis for Cash Creek would not act to constrain emissions of CO2. They merely reflect assessment of the level of CO2 emissions, using two different approaches to such determination, if the plant were or were not to use CCS. In particular, the analysis does not propose CCS as BACT.

[179] This comment was also accompanied by the "Best Available Control Technology (BACT) Analysis for Emissions of Carbon Dioxide," March 2009, for the proposed Hyperion Energy Center Refinery, in South Dakota, a project that would include a facility for gasification of petroleum coke. The nature of that BACT analysis is similar to that for the Cash Creek Generating Station. The BACT analysis is also a voluntary submittal. As clearly stated on page 2 of that analysis, "Current regulations do not extend to CO_2, so BACT is not applicable to CO_2 emissions..." In addition, the analysis does not select any control measures for CO_2 from the proposed facility beyond those inherent in the basic design of the proposed facility. The analysis also does not propose any limits as BACT for emissions of CO_2.

The material submitted with this comment concerning the BACT analysis for the Russell City Energy Center,[180] a natural gas-fired power plant facility in California, confirms that the use of natural gas in certain engines, as proposed by the applicant, was proposed to be accepted as BACT by the permitting authority. The material does not address a facility that would be based on coal and does not consider CCS as a control measure for CO_2 emissions.

CA 2. CO_2 BACT analyses have been prepared for Cash Creek, another coal gasification facility proposed for development in, Kentucky. The proposed Cash Creek facility is similarly situated as the proposed plant in terms of its ability sequester its CO_2 via a pipeline being contemplated by Denbury Resources that would transport the CO_2 to central Mississippi for use for enhanced oil recovery in the Gulf Coast Region. For the Acid Gas Removal portion of the gasification process, the BACT analysis for Cash Creek concludes that the potential add-on control efficiency for CO_2 would be 100 percent with this pipeline in service and 33.28 percent when this pipeline is out of service. The Illinois EPA must take this BACT analysis into account in developing BACT limits for the proposed plant.

A review of the Cash Creek CO_2 BACT analysis indicates that it simply reflects a mathematical material balance for carbon over the gasification process. It does not propose that CO_2 be sequestered. It also takes credit for the carbon that would leave the facility in the SNG product.[181]

Moreover, it is not appropriate to presume that the CO_2 pipeline contemplated by Denbury Resource will be built, much less when it will be built. In addition to other challenges that would be faced with a proposal to develop an interstate pipeline that is over 500 miles long, the development of the proposed pipeline also is currently contingent upon both the proposed plant and the Cash Creek facility being built. This is likely because there must be sufficient CO_2 available for enhanced oil recovery to make the construction of a pipeline financially attractive.

136. Power Holdings must include in its application and the Illinois EPA must review an analysis of technically feasible control options for minimizing emissions of CO_2 and other GHG during periods of startup, shutdown or malfunction of emission units and during any other time during which the sale of CO_2 is interrupted.

As previously discussed, a BACT determination for emissions of GHG from the proposed plant is not legally required or authorized. As such, consideration of control of GHG emissions during periods of startup, shutdown or malfunction and periods when sale of CO_2 is interrupted is also not required. In addition, as measures are imposed to reduce the plant's emissions of regulated pollutants during periods of startup, shutdown or malfunction, which measures act to reduce the number and duration of such periods and

[180] Excerpt from Bay Air Quality Management District, "Statement of Basis for Draft Amended Federal 'Prevention of Significant Deterioration' Permit, Russell City Energy Center, December 8, 2008, cover page, table of contents and pages 56-through 63.

[181] The stated 33.28 percent "potential control efficiency" for CO_2 for the gasification process at Cash Creek without a CO_2 pipeline in service is the percentage of the carbon in the coal feedstock that would leave the facility in the SNG product, with the remainder of the carbon being uncontrolled and emitted as CO_2. If the Denbury CO_2 pipeline were constructed and is in service, essentially 100 percent of the carbon in the feedstock would be captured with 66.72 percent of the carbon being transported by pipeline for sequestration in conjunction with use of the CO_2 for enhanced oil recovery, with the remaining 33.28 percent of the carbon leaving the facility in the SNG.

the magnitude of emissions of regulated pollutants, those measures should also serve to minimize GHG emissions from such periods.

137. Consistent with the statutory definition of BACT, long-standing practice, and the recent determinations, a BACT determination must include consideration of "clean fuels."[182] For a gasification plant, this may include the use of natural gas, fuel oil, or landfill gas in some processes (especially to replace syngas or SNG for production and combustion processes), gasification of biomass in place of some or all of the coal stock, or a combination of any of these, as readily available methods to reduce CO_2 emissions.

As previously discussed, under the current regulatory framework, emissions of emissions of CO_2, are not subject to BACT pursuant to the PSD program. Accordingly, as this comment indicates that "clean fuels" must be considered in the BACT determination for the proposed plant as a control option to reduce emissions of CO_2, such consideration is not justified as CO_2 is not currently a regulated pollutant for purposes of the PSD program.

As other comments have already suggested use of "clean fuels" must be considered in the BACT determination for the plant as a control option for emissions of pollutants that are currently regulated under the PSD program, the feasibility of clean fuels or feedstocks as a control option has already been addressed in detail elsewhere in this Responsiveness Summary. However, in summary, with respect to the gasification process itself, which would be the source of most of the CO2 emissions of the plant, biomass is not "technically feasible" as a feedstock for the proposed plant, given the nature and scale of the proposed plant. Biomass is not currently being produced in sufficient quantities to reasonably support the operation of the plant and biomass cannot be considered a commercially available feedstock. In addition, the properties of biomass and coal differ in certain key properties, which preclude gasification of a blended feedstock to produce SNG.

138. GHG are regulated pollutants for purposes of the PSD program because 40 CFR 52.21(b)(50) defines regulated pollutants to include "any pollutant that otherwise is subject to regulation under the Act." This includes CO_2, which is already regulated under both the Delaware SIP (which is adopted into federal law under the Clean Air Act), the New Source Performance Standards for Municipal Solid Waste Landfill, 40 CFR 60.33c, and the provisions 40 CFR Parts 75 that implement Section 821 of the Clean Air Act.

As already discussed, the rules cited in this comment did not make GHG into pollutants that are regulated under the Clean Air and subject to permitting under the PSD program. As explained in the Jackson Memorandum and confirmed by subsequent actions by USEPA, for a pollutant to be considered subject to regulation under the Clean Air Act, the pollutant must be subject to federal requirements that specifically control or limit emissions of the pollutant, not simply requirements related to the monitoring or reporting of emissions as required for CO_2 emissions.[183] Accordingly, the monitoring and reporting of

---

[182] For example, refer to pages 17 and 18 of the Environmental Appeal Board (EAB) ruling in the case: In re Northern Michigan University Ripley Heating Plant, Slip. Op., PSD Appeal No. 08-02 (E.A.B. 2009) "Congressional direction to permitting applicants and public officials is emphatic. In making determinations, they are to give prominent consideration to fuels."

[183] Incidentally, the Johnson Memorandum is consistent with the title of Section 821 of the Clean Air Act Amendments of 1990, as it 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

CO_2 emissions pursuant to Section 821 of the Clean Air Act Amendments of 1990[184] and certain provisions in 40 CFR Part 75 is not sufficient for CO_2 to be considered a regulated pollutant under the PSD program. The NSPS for Municipal Waste Landfills sets control requirements for emissions of "non-methane organic compounds" and does not directly regulate GHG. The Delaware rules that set standards for CO_2 emissions are not federal regulations. Rather they are state rules, which are part of a larger regulation that also sets standards for regulated pollutants.

139. The USEPA's Environmental Appeals Board (EAB) has repeatedly rejected refusals by USEPA and delegated states to apply BACT to GHG emissions under the Clean Air Act.[185] It has found that such actions were unsupported by any existing law or policy. [186] In a case involving Deseret Power Electric Cooperative, the EAB remanded the issue to Region 8 of USEPA to reconsider whether CO_2 BACT limits should be required. In a case involving Northern Michigan University, the EAB remanded the permit Michigan Department of Environmental Quality (MDEQ) for the same reasons as Deseret. It also instructed the MDEQ to consider whether N_2O is regulated under the Clean Air Act. The only legally defensible is that CO_2 is subject to regulation and, therefore, that BACT limits are required for CO_2. The Illinois EPA cannot ignore these clear directives from the EAB.

As previously explained, CO_2 and other GHG are not pollutants that are currently regulated under the federal PSD program, and therefore are not subject to the requirement for BACT under the PSD program. The decisions by the EAB cited in this comment are no longer relevant. This is because they were made <u>before</u> the issuance of the Johnson Memorandum and other subsequent actions by USEPA including its Proposed Endangerment Finding for GHG. [187]

140. Even before Administrator Jackson's letter of February 16, 2009 to David Bookbinder granting a petition for reconsideration of the Johnson Memorandum, USEPA Region 9 requested that the EAB remand the PSD permit issued for the Desert Rock plant in New Mexico based on the

---

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. It did not specify that the provisions of the Clean Air Act for PSD were to also be applicable.

[184] 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.

[185] Refer to the EAB's decisions in In re Deseret Power Electric Coop., PSD Appeal No. 07-03, slip op. at 25 (Nov. 13, 2008) and In re Northern Michigan University Ripley Heating Plant, Slip. Op., PSD Appeal No. 08-02 (E.A.B. 2009).

[186] In addition, in In re Deseret Power, in contrast to USEPA's assertion that Section 821 is somehow not part of the Clean Air Act, the EAB found that the USEPA's "past actions certainly seem to treat Section 821 as if it were part of the Act." In re Deseret Power, slip op. at 58. In addition, the EAB found that the USEPA had not supported its argument that the monitoring and reporting requirements of Section 821 and 40 CFR Part 75 do not constitute "regulation" for purposes of concluding whether CO_2 is "subject to regulation." Slip op. at 35-54.

[187] In addition, as previously discussed, the EAB did not conclude in either Deseret Power or Northern Michigan University that CO_2 or N_2O were regulated pollutants under the Clean Air Act. Rather, the EAB merely found that the position that CO_2 or N_2O were regulated pollutants under the Clean Air Act was not supported by law or USEPA policy that existed at the time that the subject permits, which were subsequently appealed, were issued.

EAB's decision in Deseret.[188] This shows that certain USEPA Regional Offices have concluded that CO_2 is subject to BACT under the Clean Air Act. The Illinois EPA should do the same.

This action does not demonstrate that CO_2 is currently a regulated pollutant, much less that certain USEPA Regional Offices have concluded that CO_2 is a regulated pollutant. The PSD permit issued for the Desert Rock project, and subsequently appealed, was issued after the EAB's decision in Deseret but before the Johnson Memorandum. Accordingly, USEPA Region 9 arguably could not rely on the Johnson Memorandum in explaining on appeal why CO_2 was not considered a regulated pollutant for the purposes of the PSD program. Thus it requested that the EAB remand the permit back to USEPA Region 9 to enable it to reconsider its action on the application.[189]

141. Section 302(g) of the Clean Air Act defines "air pollutant" expansively to mean "an air pollutant agent or combination of such agents, including any physical, chemical, biological, radioactive . . . substance or matter which is emitted into or otherwise enters into the ambient air." In 2007, the U.S. Supreme Court confirmed in Massachusetts v. EPA, 127 S.Ct. 1438 (2007), that CO2 and other GHG fit within this broad definition. The Court held that it is "unambiguous" that the "sweeping definition" of air pollutant found in the Act "embraces all airborne compounds of any stripe," including CO2 and other GHG greenhouse gases." Opinion at 1459-60.

The Illinois EPA agrees that GHG are pollutants. However, the relevant legal question is whether they are <u>regulated</u> pollutants. As explained in response to other comments, GHG are not yet regulated pollutants.

142. In April 2009, USEPA issued a draft endangerment finding for CO_2 and other GHG.[24] USEPA has now officially declared that CO_2 and other GHG are air pollutants that "may be reasonably anticipated to endanger public health and welfare," as defined under the Clean Air Act. Although CO_2 is already regulated under other parts of the Clean Air Act, as explained in other comments, with a final endangerment finding, EPA is obligated be Section 202 of the Clean Air Act to begin the process of regulating emissions of GHG from motor vehicles.

GHG cannot be considered regulated pollutants under the Clean Air Act based on the actions by USEPA cited in this comment. As indicated in this comment, the USEPA has only made a proposed endangerment finding for GHG. In addition, USEPA has not yet begun to regulate emissions of GHG from motor vehicles, only having recently proposed rules that would control CO_2 emissions from certain motor vehicles.

143. CO_2 is a regulated pollutant under the Clean Air Act because it is actually regulated under the Act. In particular, Section 821 of the Clean Air Act Amendments of 1990 required USEPA to adopt regulations to require certain sources, including coal-fired electric generating stations, to

---

[188] See Notice of Partial Withdrawal of Permit, In re Desert Rock Energy Company LLC, PSD Appeal Nos. 08-03, 08-04, 08-05 and 08-06, Docket Entry No. 60 (Jan. 8, 2009) (attached as Exhibit 17).

[189] There were a number of other issues raised in the appeal of the permit for Desert Rock besides the status of CO_2. In light of some of these issues, as well as the CO2 issue, USEPA Region 9 decided that the permitting process would be better served by it further consideration of the application rather than continuing with review of those issues by the EAB in an appeal proceeding. Thus USEPA Region 9 sought a "voluntary remand" of the permit from EAB, which the EAB granted. In its Remand Order, the EAB also confirmed that it was appropriate for USEPA Region 9 to reconsider its BACT determination as it had initially declined to consider IGCC technology in the BACT analysis that it conducted for the proposed Desert Rock plant.

monitor CO_2 emissions and report monitoring data to USEPA.[190] USEPA subsequently adopted the required regulations.[191, 192]

While collection of emission data may constitute a certain form of regulation of a pollutant, it does not make CO_2 a regulated pollutant for purposes of the PSD program. This was addressed by the Johnson Memorandum and is confirmed by subsequent actions by the USEPA, including the Proposed Endangerment Finding for GHG.

144. CO_2 and methane are also regulated under the Clean Air Act as they are component of landfill gas. USEPA has adopted standards of performance for municipal solid waste (MSW) landfill emissions under Section 111 of the Clean Air Act. "MSW landfill emissions" are defined as "gas generated by the decomposition of organic waste deposited in an MSW landfill or derived from the evolution of organic compounds in the waste." 40 CFR 60.751. USEPA has specifically identified CO_2 as one of the components of the regulated "MSW landfill emissions."[193] Thus, CO_2 is regulated through the landfill emission regulations at 40 CFR Part 60 Subparts WWW.[194]

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.

145. CO_2 is also subject to regulation under the Clean Air Act through USEPA's recent approval of revisions to the SIP for the State of Delaware that added various CO_2 regulations to. 73 FR 23,101 (April 29, 2008); 40 CFR 52.420(c). This revision approved CO_2 emission limits and operating requirements, record keeping and reporting requirements, and CO_2 emissions certification, compliance, and enforcement obligations for new and existing stationary electric generators. Del. Admin. Code 7 1000 1144.[195] USEPA's approval was made "in accordance with

[190] The United States Supreme Court has found recordkeeping and reporting requirements to constitute regulation in other contexts. Buckley v. Am. Constitutional Law Found., Inc., 525 U.S. 182, 204 (1999) (holding that compelled reporting of ballot initiative petition circulators' names was impermissible regulation of speech and association rights); Riley v. Nat'l Fed'n of the Blind, Inc., 487 U.S. 781, 798-99 (1988) (compelled reporting of professional fundraiser status is impermissible regulation of speech); Buckley v. Valeo, 424 U.S.1, 66-68 (1976) (evaluating recordkeeping, reporting, and disclosure requirements as regulation of political speech). Therefore, by requiring "regulation" of CO_2 in Section 821, Congress clearly made CO_2 "subject to regulation" for purposes of the BACT requirement of the PSD program.

[191] In 1993, USEPA adopted regulations requiring monitoring of the CO_2 emissions of subject sources with installation, certification, operation, and maintenance of continuous emission monitoring systems or alternative methods (40 CFR 75.1(b) and 75.10(a)(3)) preparation and maintenance of monitoring plans (40 CFR 75.33), maintenance of certain records (40 CFR.75.57), and reporting of certain data to USEPA (40 CFR 75.60 – 64). Additionally, 40 CFR 75.5 requires operators of subject sources to comply with these regulations, providing that a violation of applicable requirement is a violation of the Clean Air Act.

[192] Numerous states, including Illinois, Wisconsin, Indiana, and Michigan have included CO_2 monitoring, record keeping, and reporting requirements in Title V permits. USEPA has also enforced these CO_2 monitoring regulations under the Clean Air Act on a number of occasions. It is, therefore, clear that CO_2 is subject to regulation under the Clean Air Act.

[193] See USEPA, *Air Emissions from Municipal Solid Waste Landfills – Background Information for Final Standards and Guidelines*, USEPA, EPA-453/R-94-021 (Dec. 1995), which explains that MSW landfill emissions or landfill gas is composed of methane, CO2, and NMOC.

[194] See also 56 FR 24468 (May 30, 1991), which provides that "Today's notice designates air emissions from MSW landfills, hereafter referred to as 'MSW landfill emissions,' as the air pollutant to be controlled."

[195] USEPA informed the EAB of this action in the appeal proceeding concerning Deseret Power, thereby acknowledging the potential significance of this action. This occurred in a letter date September 9, 2008 from Brian Doster, USEPA Office of General Counsel, to Erika Durr, EAB. "…Office of General Counsel… believe that it is incumbent on them, in

the Clean Air Act," 73 FR 23,101, and by approving these provisions as part of Delaware's SIP, the USEPA made CO_2 "subject to regulation" under the Act, as SIPs are developed pursuant to Sections 110 and 113 of the Act and become federally enforceable upon USEPA approval. As such, the Delaware SIP approval also demonstrates that CO_2 is subject to regulation under the Clean Air Act for purposes of triggering the BACT requirements.

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 the Johnson Memorandum rejects the position put forth in this comment. This 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.[196] 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 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.[197] 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

---

recognition of a duty of candor, to inform the Board of a recent action by the Agency… EPA Region 3 issued a final approval of a Delaware State Implementation Plan (SIP) revision incorporating state regulations which include specific limitations on the rate of several pollutants, including CO2…"

196 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 "subject to regulation" for purposes of the PSD program.

197 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."

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.

146. 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.

As already discussed, the cited actions do not demonstrate considered judgment by USEPA to treat CO_2 as a regulated air pollutant, so as to rebut the Johnson Memorandum and subsequent actions by USEPA.

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.[198] In addition, 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 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.

147. 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 affected sources subject to those requirements pursuant to the federal regulations under the federal Acid Rain Program The inclusion in Illinois' Title V permits of these requirements of 40 CFR Part 75 for monitoring, recordkeeping and reporting of CO_2 emissions is consistent with the Title V permit program, 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.[199]

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 Johnson Memorandum. 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

---

[198] 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.

[199] 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).

included in Illinois' CAAPP permits pursuant to Illinois' Environmental Protection Act.[200] 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."

148. Pollutants regulated by state implementation plans (SIPs) approved by USEPA are regulated under the Clean Air Act. N_2O is regulated in at least Wisconsin's SIP and therefore is regulated under the Clean Air Act.[201] Once a state rule for a pollutant is approved by USEPA as a part of a SIP, that pollutant is subject to regulation under the Clean Air Act.[202] Therefore, BACT limits are also required for the emissions of N_2O from the proposed plant.

As is the case for CO_2, the 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 plant. 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 the Johnson Memorandum.

149. Congress' 2008 appropriations legislation further demonstrates that CO_2 is currently regulated under the Clean Air Act. In its Fiscal Year 2008 Consolidated Appropriations Act, Congress specifically required USEPA to undertake rulemaking to establish monitoring and reporting requirements for all GHG (including CO2), economy wide. H.R. 2764; Public Law 110–161, at 285 (enacted Dec. 26, 2007). Congress made clear that the agency is "to use its existing authority under the Clean Air Act" including "existing reporting requirements for electric generating units under section 821 of the Clean Air Act" in adopting these regulations. [203] This action by Congress not only confirms that Section 821 is part of the Clean Air Act, but also establishes a separate and distinct statutory obligation to regulate CO_2 through mandatory emission monitoring requirements under the Act. In fact, the USEPA's regulatory obligations under the Appropriations Act are much broader than its duties under Section 821 as the Appropriations Act requires economy wide reporting.

The action by Congress cited in this comment does not demonstrate that emissions of CO_2 are currently regulated pollutants for purposes of the Clean Air Act and the federal PSD

---

[200] 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.

[201] *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).

[202] 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.

[203] Conference Report for the Consolidated Appropriations Act, at 1254.

program. Collection of CO_2 emission data from certain sources was already occurring pursuant to Section 821 of the Clean Air Act. The cited action merely expands the range of sources from which such data would be collected.[204] In addition, if CO_2 were already being regulated, as also argued by this commenter, the cited action by Congress would have been unnecessary. Sources of CO_2 emission would already be subject to permitting and requirements for reporting of emission data under the Clean Air Act. Congress would merely have had to instruct USEPA to carry out the current Clean Air Act, without instructing it to adopt additional regulations for collections of CO_2 emission data.

150. As discussed in my comments for CO_2, pollutants regulated by approved State Implementation Plans are regulated under the Clean Air Act. N_2O is such a pollutant as it is regulated in at least one State Implementation Plan, and therefore, is not only subject to, but is regulated under the Clean Air Act.[205] Therefore, BACT is also required for emissions of N_2O.

This comment does not demonstrate that N_2O is a regulated pollutant for purposes of the PSD program. As a legal matter, the circumstances and status of N_2O are currently the same as those of CO_2.

151. It is clear that CO_2 and other GHG are also subject to regulation under the Clean Air Act because "subject to regulation" means "capable of being regulated" and is not limited to pollutants that are "currently regulated." Federal regulations define "regulated NSR pollutants" to include not only air pollutants for which there are NAAQS under Section 109 of the Act, standards of performance for new sources under Section 111 of the Act, or standards under or established by Title VI of the Act (relating to acid deposition control), but also "[a]ny pollutant that is otherwise subject to regulation under the Act." 40 CFR 52.21(b)(50).

The term "subject to regulation" does not mean "capable of being regulated." This would be a ridiculous interpretation of the term "subject to regulation" This is because all manner of substances are capable of being regulated, i.e., subjected to limits. This interpretation also lacks a tie to the potential occurrence of deleterious or polluting effects from the emissions of a substance. As is clear from the cited definition of regulated NSR pollutant, the term "regulated" means actually subject to requirement that limit or control emissions of a pollutant, not the hypothetical possibility of regulation.

152. In addition to being required to set BACT limits for GHG emissions from the proposed plant, the Illinois EPA is authorized to take steps to avoid or minimize such emissions, including the authority to set limits for GHG emissions and/or require offsets for GHG emissions. One source of such authority is Section 165(a) (2) of the Clean Air Act. Section 165(a)(2) gives a permitting authority broad discretion to impose permit conditions that go beyond the basic requirements of BACT in order to protect air quality.[206] Under Section 165(a)(2) of the Clean Air Act, the Illinois EPA should consider such additional permit conditions on its own initiative.

This comment does not demonstrate that the permit for the proposed plant should address GHG emissions. While a permitting authority may have authority to impose conditions in a

---

[204] Given the origin and nature of this rulemaking, it is very unlikely that these rules will be successfully challenged and struck down by the courts. Thus, as a matter of federal law, when the proposed plant begins operation, Power Holdings will be required to report actual GHG emissions to USEPA in accordance with applicable provisions of these rules.

[205] See Wis. Stat. §§ 285.60 (requiring air permits for all sources not otherwise exempted), 285.62(1); Wis. Admin. Code § NR 407.05, Table 3 (requiring permit application to include Nitrous Oxides if greater than 2,000 lbs/year). N_20 is also regulated under Wis. Admin. Code § NR 438.03(1)(a) and Table 1, adopted under the Act at 40 CFR 52.2570(c)(70)(i).

[206] Refer to In re Prairie State Generating Co., PSD Appeal No. 05-05, slip op. at 40 (EAB. 2006), quoting NSR Manual at B.13.

PSD permit to protect air quality, that authority is used to address emissions of regulated pollutants for which air quality standards have been set or regulations have been adopted requiring control of emissions. Moreover, that authority is used in circumstances where there is a more direct linkage between the emissions of a pollutant and air quality than is currently present with GHG emissions. In this regard, comments have not been submitted that show that the proposed presence of GHG in the atmosphere directly constitutes a threat to air quality. Rather emissions of GHG are an indirect threat to the environment, as they are causing global warming and climate change. In this regard, emissions of GHG are similar to the emissions of the acidic precursors that contribute to acid rain and the emissions of ozone depleting substances that contribute to depletion of stratospheric ozone. In both cases, the environmental problem was addressed by comprehensive regulations for control of the precursor pollutants, not by case-by-case actions on permit applications, independent of other authority to regulate emissions of the relevant precursor pollutant.

Incidentally, Section 165(a)(2) of the Clean Air Act does not actually provide the authority or act in the manner indicated by this comment. Section 165(a)(2) addresses the procedural steps that must take place before a PSD permit may be issued. The ability of permitting authorities to include conditions in federal PSD permits and the nature and extent of such authority has been established through USEPA policy and review of permits by the EAB upon appeal. As related to alternatives to a proposed project, Section 165(a)(2) of the Clean Air Act only provides that a permitting authority must accept public comments that address alternatives to the proposed project and, presumably, appropriate respond to those comments.

153. Under the PSD program, a permitting authority has broad discretion in the scope of the BACT analysis. For example, the EAB has found that while a permitting authority may not be required to evaluate the substitution of a combustion turbine for a proposed coal-fired steam boiler plant, it does have the authority to do so.[207] The Illinois EPA should exercise this discretion to require control of GHG emissions from the proposed plant.

This comment does not demonstrate that emissions of GHG from the proposed plant should be addressed in the BACT determination for the proposed plant. The cases cited in support this comment address the scope of BACT analyses for pollutants that are regulated under the Clean Air Act. They do not demonstrate that a permitting authority has discretion or authority as part of a BACT determination to directly address pollutants that are not regulated as suggested by this comment.

154. As recognized by USEPA, "…a PSD permitting authority still has an obligation under section 165(a)(2) to consider and respond to relevant public comments on alternatives to the proposed source," and that a "PSD permitting authority has discretion under the Clean Air Act to modify the PSD permit based on comments raising alternatives or other appropriate considerations." Brief of the EPA Office of Air and Radiation and Region V, In re Prairie State, PSD Appeal 05-05, 12 E.A.D. 176 (EAB, Aug. 24, 2006). Here, these comments expressly require Illinois EPA to fulfill this duty. Moreover, the EAB has made clear that a permitting authority has discretion to impose requirements in a permit based on consideration of "alternatives," whether or not

[207] See In re Knauf Fiber Glass, GmbH, 8 E.A.D. 121, 136 (EAB 1999) (citing NSR Manual at B.13-B.14); see also USEPA Region 9's Motion for Voluntary Remand at 19-20, In re Desert Rock Power Company, LLC, PSD Appeal Nos. 08-03, 08-04, 08-05 and 08-06 (April 27, 2009) ("The Administrator and EAB have generally recognized that the decision about whether to include a lower polluting process in the list of potentially-applicable control options compiled at Step 1 of the top-down BACT analysis is a matter within the discretion of the PSD permitting authority . . . Individual permitting authorities have the discretion to conduct a broader BACT analysis that reflects consideration of alternative production processes when appropriate . . . .").

comments raise the issues.[208] Accordingly, the Illinois EPA can engage in a wide-ranging exploration of alternatives regarding the proposed plant. The Illinois EPA clearly has the discretion to require specific evaluation and control of CO_2 emissions, and/or to require other action to mitigate potential global warming impacts. Failure to do so in this case would be breach of the Illinois EPA's obligations to the people of Illinois.

The Illinois EPA has considered "on its own initiative" whether the proposed project is consistent with the broad environmental objective of improving energy efficiency and conserving fuels, as use of fuel results not only in emissions but other impacts on the environment. While the development of the plant would potentially increase the availability of natural gas, as the supply of natural gas would include SNG from the proposed plant, the plant is not inconsistent with the broad environmental objective of improving energy efficiency. The plant will not lower the price of natural gas from current levels, which encourage and provide an incentive for improved energy efficiency.[209] In the near term, SNG from the plant would be more costly than natural gas from geological deposits. This is because the production of SNG by the proposed plant will be more complicated and thus more costly than "naturally occurring" natural gas currently produced at gas and oil fields.[210,] Only in the long term, when the cost of domestically produced natural gas has increased and is at levels that provide even greater incentive for energy efficiency, would the SNG from the proposed plant become a less expensive source of natural gas.[211]

155. To date, there has been no specific assessment of available measures or options to reduce GHG emissions from the proposed plant. The Illinois EPA must consider and could require any number of possible actions to address the CO_2 emissions of the proposed plant. Options include requiring construction of a more efficient plant, use of biomass feedstock, use of lower emitting fuels to run plant processes, and requiring the purchase of CO_2 offsets,[212] or some combination of these approaches or others. The Illinois EPA should only issue a permit for the proposed plant if it

[208] As discussed by the EAB in In re Prairie State, PSD Appeal 05-05 (Aug. 24, 2006) (quoting the NSR Workshop Manual at B.13), "Indeed, the permitting authority is not required to wait until an "alternative" is suggested in the public comments before it may exercise the discretion to consider the alternative. Instead, the permit issuer may identify an alternative on its own. This interpretation of the authority conferred by CAA section 165(a)(2)'s reference to "alternatives" is consistent with the USEPA's longstanding policy that '…this is an aspect of the PSD permitting process in which states have the discretion to engage in a broader analysis if they so desire.'"

[209] It should be noted that even if the proposed plant would clearly be contrary to the broad environmental objective of energy efficiency, it would still likely not be a sufficient basis to deny the permit for the plant, as discussed in response to other comments.

[210] The production of SNG is more complicated than the production of naturally occurring natural gas. The feedstock for SNG production, coal, must first be mined, which is more labor intensive than drilling gas and oil wells. Since coal is a solid, it must first be gasified to convert it into a gaseous form. The raw gas from gasification must undergo cleanup for particulate matter as well as sulfur. Finally since the cleaned gas still is not methane, the gas must undergo methanation. This makes SNG from the proposed plant more costly than natural gas from "easily" recoverable geological deposits.

However, the cost of "geological" natural gas will generally increase over time as easily recovered reserves are gradually exhausted and natural gas is increasingly obtained from more costly reserves. Eventually, the cost of natural gas from geological sources would become equal to and then greater than SNG from the proposed plant.

[211] In the long term, when SNG from the proposed plant is less costly than geological natural gas, the availability of SNG from the proposed plant would generally act to stabilize or moderate fuel costs for consumers. Even before this point, the availability of SNG from the plant, as it would be another source of natural gas, could also serve to moderate volatility in the cost of natural gas.

[212] Offsets can be an essential component of reducing CO2 emissions because they can be implemented quickly for a relatively low cost. Offsets can be provided by things such as such as programs to increase the energy efficiency in buildings, factories, or transportation, projects that generate electricity from renewable wind or solar energy, shutting down older less efficient power plants, and programs to increase capture of CO2 by forests and agriculture. An advantage of offsets is that they often result in other environmental, social, and economic co-benefits such as reductions in emissions of other pollutants, restoration of degraded lands, improvement in watersheds and water quality, and creation of jobs

fully incorporates all available measures for reducing GHGs, sets appropriate GHG-related emission limits, and/or imposes offset requirements for GHG emissions.

The Illinois EPA has appropriately considered the "new" suggestions made by this comment as suggested alternatives for the proposed plant. Further consideration of the use biomass feedstock is not needed, as it has already been considered in response to a comment suggesting that biomass feedstock should be required as BACT. It was determined to be infeasible given the size and circumstances of the proposed plant. Use of lower emitting fuels has also already been considered in response to a comment related to the BACT analysis. The issued permit requires that natural gas be used as the fuel in the plant's superheaters. (Natural gas was already required for the auxiliary boiler.)

With regard to the efficiency of the plant, it should be assumed that the plant will be designed with equipment and features that can be safely operated and provide an appropriate balance of capital cost, operating cost, reliability, and efficiency, as would be present with the design of a major new chemical process plant. As the plant would have multiple process units that must operate together in an integrated manner and efficiency would only be one factor in the design of the plant, it should not be expected that an independent evaluation of the design of the plant would be able to identify a more efficient design that would satisfy other needs that must be met by the design of the plant.[213]

With regard to purchase of CO_2 offsets, given that CO_2 is not currently a regulated pollutant for purposes of the federal PSD program, it would not be appropriate to impose a requirement on the proposed plant whose principal justification would be to control emissions of CO_2. In addition, as with CCS, requiring CO_2 offsets would be contrary to the "rule-of-law." While CO_2 offsets are currently a more straight forward matter technically than CCS, the mechanisms and institutions that might be used to obtain those offsets are also in their infancy. It is also only possible to speculate on the cost of such offsets over time, particularly as control programs are adopted for CO_2 emissions that could compete for such offsets. Lastly, if CO_2 offsets are required of the proposed plant, considerations of equity under the rule of law would argue that existing sources with significant CO2 emissions should also be required to provide CO_2 offsets to mitigate the effects of their emissions. However, this cannot occur without regulatory adoption of a control program for CO_2 emissions.. Finally, as with CCS, as the proposed plant is directly addressed by the Illinois Public Utilities Act, that Act should be considered to set Illinois' policy with respect to requirements for the plant for CCS or CO_2 offsets. That is, these measures should be encouraged by the State of Illinois, as is occurring as that Act, but should not be mandated at this time. This is a sound approach to the proposed plant until a regulatory program is adopted that would address the plant's CO_2 emissions.

The "combination" of the options suggested by this comment would not avoid the difficulties posed by the individual options, and could act to compound them. As such, combinations of options also cannot be justified.

---

[213] **In this regard, the design of the proposed plant should not be compared to the selection process that might be followed by an individual for purchase of a new refrigerator or other appliance. That is a far simpler process as that individual is picking from a limited number of models of a particular type of unit that generally meet his or her needs. Considering the suitable units, the individual must then only make a decision balancing initial cost against energy efficiency and future operating costs. Moreover, the relevant information to make this evaluation is readily available from the price tag and the energy information posted on the unit. The individual is not seeking bids from multiple potential suppliers for multiple pieces of equipment to design and fabricate the various units that would be part of an integrated chemical processing facility, like the proposed plant.**

156. Under Section 165(a)(2) of the Clean Air Act, the Illinois EPA must consider the "no-build" option, where the permit would be denied based on considerations related to emissions of CO_2 and other pollutants.

In response to this comment, which succinctly observes that one alternative to the proposed plant is not building a plant at all, the Illinois EPA has considered the "no-build" option. The Illinois EPA can readily respond to and reject this alternative. The potential benefits for Illinois from the plant would be blocked if the permit were denied, as it would effectively block further effort to develop the plant. If the plant is built, it would support the economy of Southern Illinois, and Illinois generally, as it would provide jobs, purchase raw materials, equipment and services, and pay taxes. The plant would produce SNG, essentially natural gas, adding to Illinois' potential supply of fuel or energy. It would produce SNG from Illinois coal, taking advantage of an energy resource in the state. Reliable and affordable supplies of energy, including natural gas, are important to the economic well-being of Illinois and its residents. This is particularly true for natural gas, which is a clean fuel that would contribute to lower emissions in the areas in which it used, as compared to use of other available fuels. At the same time, as already discussed, the availability of SNG from the plant should not act to inhibit actions to improve energy efficiency and generally conserve energy and reduce consumption of natural gas. As a practical matter, it also should be assumed that the proposed plant would only be built if there is a reasonable expectation that there would actually be a market or demand for the SNG produced by the plant.

As related to its environmental impacts, the proposed plant must be constructed and operated to comply with all applicable environmental regulations. This would include any changes to the operation of the plant as needed to comply with future laws and rules that are adopted that address emissions of CO_2 and other GHG. As capture of CO_2 would be part of the initial design of the plant, the plant would be constructed so as to facilitate compliance with such requirements. Finally, while blocking the continued development of the proposed plant would "eliminate" its potential GHG emissions, it would do nothing to reduce actual GHG emissions from existing sources.

157. The Illinois EPA cannot issue this permit without requiring mitigation of the global warming impacts because it would allow the proposed plant to emit CO_2 and other GHG in such quantities that would cause or tend to cause air pollution.[214] This would be contrary to 35 IAC 201.141, which provides that "[N]o person shall cause or threaten or allow the discharge or emission of any contaminant into the environment in any State so as, either alone or in combination with other sources, to cause or tend to cause air pollution in Illinois." The plant's emissions of CO2 and other GHG would constitute air pollution, as they will accelerate global warming and cause further harm to human, plant and animal life. The concentrations of GHG in the atmosphere are already at levels at which adverse impacts have begun.

This comment does not show that a permit should not be issued for the proposed plant. The proposition put forth in this comment is flawed in several respects. First, the statutory framework for "air pollution," as cited by the comment, is geared towards enforcement, not

[214] "Air pollution" is defined by 35 IAC 201.102 to mean "the presence in the atmosphere of one or more air contaminants in sufficient quantities and of such characteristics and duration as to be injurious to human, plant, or animal life, to health."

regulation.[215] The language of both the statute and regulation is that of prohibition, whose redress would normally be found in an injunction or other equitable remedy before a court. It is not language that creates enabling authority through which the Illinois EPA could lawfully seek to "mitigate" or regulate the impacts of CO_2 emissions during permitting. Moreover, the concept of a statutory prohibition does not lend itself to partial restraints; the offending conduct is to be prohibited, not mitigated or sanctioned. Given the absence of proven technology to eliminate CO_2 emissions from fossil fuel combustion, it is not clear how the remaining amounts of CO_2 that the commenter would allow from the plant could be judged any less harmful or offending to society if, as alleged, CO_2 emissions are broadly deemed a form of "air pollution." Finally, to the extent that the commenter would have the Illinois EPA itself constrained through such a prohibition, the premise is likewise misplaced. State courts have rejected the notion that the Illinois EPA is subject to enforcement when acting in its established role as a permitting authority.

The argument advanced by the comment also fails to satisfy principles of "fundamental proof." A complainant seeking to enforce a right conferred by statute is generally required to prove both causation and injury. In the scientific community, as well as among public policy-makers, the notion of cause and effect is relative. However, in a courtroom, causation takes on a rigorous meaning, that is both highly demanding and structured. Generally speaking, factual causation is shown when a reasonable certainty exists that the alleged conduct caused an injury. Mere conjecture or speculation of causation is not enough. Similarly, the alleged injury must be amenable to proof, not merely contingent, remote or prospective. A speculative possibility of an injury does not satisfy this element. Given the difficulties in assessing the extent of global warming, not to mention assigning responsibility for harm to individual sources of CO_2 emission, the enforcement approach to regulating CO_2 emissions recommended by the commenter is clearly ill-advised.

Finally, treating CO_2 emissions as a regulated air pollutant under Illinois law would be wholly unconventional. CO_2 is a compound that is present in the earth's atmosphere, occurring both naturally and as a product of fossil fuel combustion. CO_2 in the atmosphere has not been commonly regarded as an air "pollutant." Indeed, the ecosphere depends upon the presence of CO_2 emissions to support green plants. Historically, CO_2 in the ambient atmosphere has not been considered harmful to humans or the environment. While the statutory definition of air pollutant in Section 3.165 of the Environmental Protection Act is broad, citing to "any solid, liquid, or gaseous matter… or form of energy, from whatever source…" and CO_2 would seem to fall within the meaning of the term, it should not be presumed that courts would reach the same conclusion. Courts are reluctant to construe language literally when it would defeat the purpose or intent of the law, leading to an outcome that was not contemplated by the legislature.[216]

---

[215] **"Air pollution" is defined by Illinois law, in Section 3.115 of Illinois' Environmental Protection Act, is the "presence in the atmosphere of one or more contaminants in sufficient quantities and of such characteristics and duration as to be injurious to human health, plant, or animal life, to health, or to property, or to unreasonably interfere with the enjoyment of life or property." As with nuisance law, the statutory definition contemplates an activity that creates such injury or unreasonable consequences that the law will presume damage and provide redress. Notably, the statute refers to the definition in the general air pollution prohibition that is found in Section 9(a) of the Act. The definition of air pollution adopted by the Pollution Control Board at 35 IAC 201.102 , which the commenter refers, is nearly identical.**

[216] **Interestingly, Professor Currie, widely known as the principal draftsman of Illinois' Environmental Protection Act, expressed concerns about reading too much into certain elements of the definition of air pollution. In a 1976 law review article, Professor Currie remarked: "To seize upon broad definitional language of modest purpose to expand state regulation into areas not traditionally thought of as pollution smacks too much of invading the province of the legislature." See Enforcement Under the Illinois Pollution Law, Northwestern University Law Review, Vol. 70, No. 3 (July-August 1976).**

158. The scientific debate about whether humans cause climate change and whether it is a problem is over and has been for a while, certainly since the adoption of the Kyoto Protocol in December 1997. A further consensus is emerging that present atmospheric levels of CO_2 (386 ppm and rising) are already in the danger zone. Earth's climate sensitivity, the temperature rise for a given amount of CO_2 emissions, is higher than previously thought and the effect is long lasting. Even after CO_2 emissions cease, atmospheric temperatures will not drop significantly for decades.

The Illinois EPA agrees. This is why it is important that regulatory programs to control emissions of GHG be adopted on a national and international level be taken to address emissions of GHG and climate change.

159. The Intergovernmental Panel on Climate Change (IPCC) has found that due to emissions of GHG, principally CO_2, from human activity, the concentrations of GHG in the atmosphere are at unprecedented levels.[35] The global concentration of CO_2 has increased from a pre-industrial value of about 280 to about 380 ppm in 2005. This exceeds by far the historical range over the last 650,000 years (180 to 300 ppm CO_2).[217] In the absence of corrective action, the rates of CO_2 emissions continue to rise. [218] According to a prominent expert, "The world is already at or above the worst case scenarios…. In terms of emissions, the earth is moving past the most pessimistic estimates of the IPCC and by some assessments is above that red line."[219] In light of these findings, climate experts urge immediate action to curtail emissions of CO_2 and other GHG.[220] Rajendra Pachauri of the IPCC asserts "If there is no action before 2012, that's too late…. What we do in the next two to three years will determine our future. This is the defining moment."[221]

---

[217] 36 IPCC Working Group I, Climate Change 2007: The Physical Science Basis, Summary for Policymakers at ES-2 .

[218] The amount of CO_2 now in the atmosphere also diminishes the earth's ability to continue to remove or assimilate the amount of CO_2 that is emitted into the atmosphere. Through the carbon cycle, the earth is able to remove CO_2 from the atmosphere, with oceans and forests acting as "carbon sinks" absorbing CO_2 from the atmosphere, but only at certain rates and to a certain point. The increasing levels of anthropogenic emissions of CO_2, such as power plant emissions, have exceeded the capacity and disrupted the carbon cycle. For example, the ocean's uptake of further CO_2 is slowing as CO_2 concentrations increase. In some areas, oceans are reaching their CO_2 saturation points. (Refer to C. Le Quere and others, "Saturation of the Southern Ocean CO2 sink due to recent climate change," Science, 316 (5832), 1735-1738, 2007.) In addition, once the saturation point is reached, when a carbon sink is no longer able to absorb CO_2, it may actually begin releasing accumulated CO_2 into the atmosphere. As a consequence, small temperature changes can have large impacts on climate. (Testimony of James Hansen, Director of NASA's Goddard Institute for Space Studies.) The inevitable result of the disruption of the carbon cycle is increasing concentrations of CO_2 in the atmosphere, which leads to global warming with the potential for catastrophic consequences for humans and other species. As explained in the IPCC Working Group I Report: Climate Chance 2007, rising atmospheric CO2 concentrations are the leading cause of and most influential factor in global warming. Based on the observed data from 75 studies, the IPCC has concluded that "Warming of the climate system is unequivocal." The IPCC reports the temperature increase since the 1950s is very likely due to the increase in human caused GHG emissions and cannot be due to natural causes alone. The IPCC considered direct indicators of climate change, including global average air and ocean temperatures, ice and snow melt patterns, rising sea levels, changes in arctic temperatures, ocean salinity, wind patterns, and incidence of extreme weather events.

[219] 41 E. Rosenthal, "U.N. Report Describes Risks of Inaction on Climate Changes," New York Times, November 17, 2007.

[220] The IPCC in its Working Group I Report: Climate Chance 2007, also finds that increasing emissions of CO2 and other GHG are triggering climactic feedback that likely will exacerbate climate change. For example, the melting and shrinking of the extent of Arctic ice, which occurs as the atmosphere warms, can itself trigger additional warming. This is because the open ocean and ice-free land are less reflective than the ice and more of the sun's heat is absorbed rather being reflected back out into space. Given these types of feedback that exacerbate warming, it is difficult for scientific models to accurately predict the full extent of climate change that will occur if emissions of GHG continue unabated.

[221] The International Energy Agency (IEA) has warned that "[u]rgent action is needed if greenhouse-gas concentrations are to be stabilised at a level that would prevent dangerous interference with the climate system." The IEA specifically focused on the threat posed by the increased construction of coal-fired power plants. According to the IEA, "…government action must focus on curbing the rapid growth in CO emissions from coal-fired power stations – the primary cause of the surge in global emissions in the last few years." IEA World Energy Outlook 2007, Executive Summary, page 12.

While these comments describe the serious nature of global warming and climate change as caused by anthropogenic GHG emissions, global warming and climate change do not provide a legal basis to address GHG emissions in the permit for the proposed plant given that GHG are not currently regulated pollutants under the Clean Air Act, as previously discussed. Moreover, these general concerns global warming and climate change do not translate into specific effects for which the proposed plant can or should be held accountable as a legal matter. This is because global warming and associated climate change are the result of the overall anthropogenic GHG emissions. As such, the identification of mandatory actions to address GHG emissions should be determined of law or regulation, rather than case-by-case action on individual permit application. In this regard, Congress is currently discussing what actions that should be taken at the national level to comprehensively and responsibly address GHG emissions in the United States.[222]

160. Numerous scientific studies directly link climate change with significant public health, environmental, economic, and ecological impacts.[58] Such impacts include direct heat-related effects, extreme weather events, climate-sensitive disease impacts, air quality effects, agricultural effects (and related impacts on nutrition), population displacement and social disruption, and property damage. Ecological impacts include effects on marine life, wildlife habitat, and biodiversity. These effects are in addition to the melting of ice sheets, which would significantly raise the sea level by levels that are measured in tens of meters. Climate changes associated with global warming, such as increases in average temperature and increased incidences of extreme heat, droughts, and other extreme weather events will be experienced in and affect Illinois.

As already discussed, while global warming and climate change, as caused by anthropogenic GHG emissions, will have devastating consequences on the natural environment, in the absence of appropriate laws or regulations, global warming and climate change do not provide a legal basis to address GHG emissions in the permit for the proposed plant since GHG are not currently regulated pollutants under the Clean Air Act.

161. Certain aspects of public health are closely linked to climate and global warming is expected to have numerous significant impacts on human health. The only reasonable way to address these threats to human health is to address the underlying problem, global warming, as the U.S. and international public health communities are not prepared for multiple large scale disasters, induced by global warming. The USEPA warns:

Throughout the world, the prevalence of some diseases and other threats to human health directly relate to local climate. Extreme temperatures can lead directly to loss of life, while climate-related disturbances in ecological systems, such as changes in the range of infective parasites, can indirectly impact the incidence of serious infectious diseases. In addition, warm temperatures can increase air and water pollution, which in turn threaten human health.[223]

As already discussed, while global warming and climate change, as caused by anthropogenic GHG emissions, will have serious consequences for public health, in the absence of appropriate laws or regulations, global warming and climate change do not

---

[222] Discussions have also taken place in Illinois concerning the appropriate actions that should be taken at the state level to address GHG emissions. Most recently, in 2006, Governor Blagojevich created the Illinois Climate Change Advisory Group to investigate this subject. While this group came forward with a number of recommendations, the downturn in the economy as well other events have interfered with implementation of those recommendations.

[223] USEPA, Climate Change, Health and Environmental Effects, http://www.epa.gov/climatechange/effects/health.html

provide a legal basis to address GHG emissions in the permit for the proposed plant since GHG are not currently regulated pollutants under the Clean Air Act.

162. The increases in GHG emissions from the proposed plant clearly would "alone or in combination with other sources" will result in "the presence in the atmosphere of . . . air contaminants in sufficient quantities and of such characteristics and duration as to be injurious …" The Illinois EPA may not issue a permit that will cause additional injury to human health and the health of animal and plant life. Pursuant to Section 165(a)(3) (C) of the Clean Air Act, Illinois EPA cannot issue a permit for the proposed plant unless and until the applicant demonstrates that emissions from the plant will not cause or contribute to air pollution in violation of this SIP-approved standard, which limits emissions and resulting ambient concentration of GHG.

The cited provision of the Clean Air Act does not bar the issuance of a permit for the proposed plant. Section 165(a)(3) (C) simply provides that the applicant for a PSD permit must demonstrate that the emissions from a proposed source would not cause or contribute to air pollution in excess of applicable emission standards or standards or performance under the Clean Air Act. In other words, the applicant for a proposed source must show that the proposed source would comply with applicable laws and rules that would apply to and govern the source's emissions. The cited provision does not address emissions of pollutants that are not subject to regulation, providing a permitting with authority to broadly address any pollutant that might be emitted from a proposed source. In addition, as already discussed, state rules at 35 IAC 210.102 and 201.141, as they directly address and prohibit air pollution, do not set an emission standard and are not amenable to enforcement as an emission standard under the Clean Air Act.

163. As the site-selection criteria related to geology and seismic conditions established in 2006 for the FutureGen project seem to have resulted in the rejection of a possible site for that project near Effingham, Illinois, the location selected for the proposed plant is also not suitable.

The site-selection criteria developed by FutureGen for its proposed project are not relevant to the proposed plant, as they were developed for a different project.[224] The proposed plant must be appropriately designed and constructed to address the geology that is present at the selected location.

164. The Illinois EPA should address GHG emissions of the proposed plant, following the lead of other of states that have already taken steps to curb GHG emissions from coal plants. For example, the State of Montana has passed a law requiring that all new electric generating units that are "primarily fueled by coal" capture and sequester at least 50 percent of their CO_2 emissions. Mt. Code 69-8-421(7).

The fact that an individual state adopts legislation addressing GHG does not make GHG "regulated air pollutants" for purposes of the federal Clean Air Act and the federal PSD program. Except where prohibited by the constitution or applicable federal law, the state legislative process can be more stringent than federal law. The state legislative process is different from the regulatory process whereby USEPA unilaterally adopts National

[224] **The site-selection criteria for FutureGen addressed that project, which is different from the proposed plant. As such, the weighting of various factors in the site-selection process would also be different. For example, as FutueGen would be a smaller facility, proximity to coal supplies and water resources may have been of lesser concern for site selection for FutureGen than they are the proposed plant. Given the developing nature of CO_2 sequestration and the financing of a demonstration plant that likely would not be feasible as a commercial venture, FutureGen may also have decided to be more selective about local geology.**

Ambient Air Quality Standards, federal New Source Performance Standards or other regulations controlling emissions of 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. In the absence of such federal regulation of GHG, the Illinois EPA cannot address GHG as regulated pollutants in the permitting of the proposed plant.

165. The Illinois EPA should address GHG emissions of the proposed plant, following the lead of other states that already taking steps to curb GHG emissions from their states. Minnesota has enacted the Next Generation Energy Act of 2007, which establishes statewide GHG reduction goals of 15 percent by 2015, 30 percent by 2025, and 80 percent by 2050, a requirement that utilities achieve a 1.5% energy efficiency saving annually in 2012 and each year thereafter. As of June 2008, the State of Washington is committed to reducing Washington's GHG emissions to 1990 levels by 2020, to 25 percent below 1990 levels by 2035, and 50 percent below 1990 levels by 2050. 2008 Wash. Laws, Chapter 14. In December 2008, the New Jersey Department of Environmental Protection (NJDEP) announced a plan to reduce New Jersey's GHG emissions to 1990 levels by 2020, followed by another reduction by 2050 to a level that is 80 percent below 2006 levels. The plan includes fossil fuel standards for electrical generating units, among other recommendations.

As previously discussed, the fact that an individual state adopts legislation or regulations or plans addressing GHG does not make GHG "regulated air pollutants" for purposes of the federal Clean Air Act and the federal PSD program. Federal action is required to make GHG regulated pollutants for purposes of the PSD program. Moreover, the cited actions by certain states are consistent with the principle that emissions of GHG should be addressed by coordinated action addressing both existing and new sources, not by piece meal action on a permit application for a proposed new source.

166. The Illinois EPA should address GHG emissions of the proposed plant, following the lead of other states that have taken steps to curb GHG emissions from generation of electricity. California has passed legislation requiring that long-term base-load power contracts of five years or longer only be made with sources that have a greenhouse gas impact no higher than that of a natural gas combined cycle plant. Cal. Pub. Util. Code § 8341. The California Public Utilities Commission and the California Energy Commission have since established the operative level as 1,100 pounds per megawatt-hour.[225] The State of Washington has passed similar legislation requiring that long-term utility financial commitments only be made with sources that have the lower of 1100 pounds of GHG emissions per megawatt-hour (lbs/MWh) or the average GHG emission output of new combined cycle natural gas thermal electric generation turbines commercially available and offered for sale. Projects that would emit more than 1,100 lbs/MWh of GHG must capture and sequester the excess. Wash. Rev. Code 80.80. As discussed in another comment, Delaware recently adopted rules limiting CO_2 emissions from electric generating units. Del. Admin. Code 7 1000 1144 Sections 3.2.1.1 and 3.2.2.1.

As previously discussed, the fact that an individual state passes legislation or regulations addressing GHG does not make them a "regulated air pollutant" for purposes of the federal Clean Air Act.. The state legislative or rulemaking process can be more stringent than national requirements. These processes are different from the regulatory process whereby USEPA unilaterally adopts air quality standards or regulations controlling emissions of

[225] California Public Utilities Commission, Greenhouse Gas Emissions Performance Standard ; California Energy Commission, SB 1368 Emission Performance Standards (

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.

167. Power Holdings has not committed to, and the draft permit does not require sequestration of CO_2. To work right, sequestration must be designed into the plant from the beginning. Adding facilities for sequestration of CO_2 later is not the answer. Even if CO_2 sequestration can be tacked on to the plant later, a retrofit will not be as efficient or economical as sequestration from the beginning. Approval of the project in its current form essentially abdicates responsibility and loses the opportunity, to address geologic sequestration of CO_2 by the proposed plant, with serious and possibly irreversible adverse consequences for global warming and climate change.

As previously explained, CO_2 is not a pollutant that is currently regulated under the federal PSD program. In addition, current circumstances do not legally support establishment of requirements for CO_2 sequestration in the permit for the proposed plant. Finally, as also explained, the financing for the proposed project, which includes whether CO_2 sequestration is addressed as part of initial construction of the plant or at a later date, likely at greater cost, is not a factor that could be considered in conjunction with the issuance of this environmental permit for the proposed plant.

168. In my opinion, it will not be possible today to obtain financing for this proposed multi-billion dollar project unless and until a sound plan is developed for the capture and sequestration of some or all of the CO_2 produced by the plant. Accordingly, a well-crafted CO_2 limit can help this project reach financial closure. For this reason also, well-crafted CO_2 emission limits for pioneering CO_2 capture and sequestration projects must provide flexibility for periods when use of CO_2 for Enhanced Oil Recovery of the infrastructure for geological sequestration is temporarily unavailable. Furthermore, the permit must address the possibility that the CO_2 pipeline may be delayed and not be available when until after the plant begins operation.

The fact that this project may ultimately not move forward absent a sound plan for managing the plant's CO_2 emissions, because of the inability of obtaining financing, is not a valid basis for the permit to include requirements related to CO_2 emissions. As previously discussed, CO_2 is not currently a regulated pollutant for purposes of the PSD program. Moreover, as observed by this comment, crafting of such requirements would be complicated as the requirements would have to address interruptions in the ability to sequester CO_2, as well as potential timing issues with the coordination of the start of plant operation and the availability of the infrastructure to sequester CO_2.

169. Other proposed gasification plants are being rejected for failure to adequately address significant CCS. On April 14, 2008, the Virginia State Corporation Commission (VSCC) denied Appalachian Power Company's application to include in its rate base the $1 billion component attributable to Virginia of the projected $2.23 billion cost of the proposed 629 MW Mountaineer Integrated Gasification Combined Cycle (IGCC) plant.[226] In that case, Appalachian Power attempted to highlight the value of IGCC for its potential to capture and sequester CO_2, yet included no estimated costs in its application for CCS. The VSCC cited the cost of CCS at $300 to $500 million in its decision. Effectively the VSCC denied this application because Appalachian Power was asserting the reason for proposing IGCC was for its superior capability to capture CO_2 without actually proposing and accounting for the cost of CCS. The application for the proposed plant shares the same flaw and should be denied.

[226] Virginia State Corporation Commission, Case PUE-2007-00068, Final Order, April 14, 2008.

The cited action taken by the Virginia State Corporation Commission (VSCC) is not relevant to the permitting of the proposed plant under the PSD program. As clearly indicated in the comment, the VSCC's action involved a request by Appalachian Power to increase its rate base for. Rate base proceedings before commerce or utility commissions, like the VSCC, address very different matters than PSD permits. Those proceedings address the cost, financing and revenue stream for a project proposed by a public utility and the role of a state in guaranteeing that revenue stream and return on the rate base or investment in the project. This is different from whether a proposed facility would be developed to comply with federal and state requirements for control of emissions.

170. The Illinois EPA should address GHG emissions of the proposed plant, following the lead of other states that have taken steps to curb GHG emissions from generation of electricity. Utility commissions in Wisconsin and Florida have rejected proposals for coal-fired power plants based, in significant part on concerns about global warming impacts.[227] In November 2007, the Washington Energy Facility Site Evaluation Council halted consideration of Energy Northwest's proposal for a 793 MW coal-fired power plant because the company had not submitted a plan for sequestering excess CO_2 emissions from the proposed plant.

The fact that state utility commissions have taken action on proposed projects based upon considerations related to emissions of GHG does not make GHG "regulated air pollutants" for purposes of the federal Clean Air Act. As specifically set out by the laws and regulation of particular states, utility commissions may consider whether projects proposed by public utilities represents a reasonable and appropriate way to address the need for power in a state, such that rates for electricity or natural gas should be set that enable the utility undertaking such project to recover and profit from its investment. This is very different than the role a permitting authority under the Clean Air Act in reviewing whether a proposed project complies with applicable requirements related to control of emissions. For this purpose, federal action by USEPA creates or defines the scope of pollutants that are considered "subject to regulation" under the Clean Air Act. This has not yet happened for GHG. In the absence of such federal regulation of GHG, the Illinois EPA cannot address GHG as regulated pollutants in the permitting of the proposed plant.

171. Although the Project Summary contemplates Power Holdings' intention to capture and sequester some or all of the CO_2 emissions from the proposed plant, the Illinois EPA has not solicited public comment on whether or how to address CO_2 emissions. The Illinois EPA also has not stated what factors it considered in making its decision not to require CO_2 controls at this plant. As a result, the public has never been provided with an opportunity to examine, consider, and react to the Illinois EPA's explanation and justification of its approach to CO_2 under this permit. Therefore, the permit is also procedurally deficient, as the public has not been provided notice as to whether, or under what conditions, the Illinois EPA would entertain limiting the plant's CO_2 emissions, or would consider alternatives that would result in lower CO_2 emissions.

The permit is not procedurally deficient. This comment does not show that the Illinois EPA was legally under a procedural obligation to specifically explain in the Project Summary prepared with the draft permit for the proposed plant why CO_2, other GHG (or other substances that are considered pollutants) are not currently considered to be regulated

[227] Business Journal of Milwaukee, PSC Rejects Alliant's Proposed Coal Plant, (Nov. 11, 2008) Thomas Content, PSC Rejects Alliant Energy's Proposed Coal Plant, Milwaukee Journal Sentinel (Nov. 11, 2008) ; Craig Pittman, PSC Bars Coal-Fired Plant, St. Petersburg Times (Sept. 6, 2007)

pollutants for purposes of the PSD program. The comment also does show that the Illinois EPA was required to discuss what was not proposed to be done in the permitting of the proposed plant with respect to pollutants that were not regulated. Indeed, the comment lacks any reference to legal requirements. The comment also does not show that the Illinois EPA was obligated to speculate on the circumstances under which CO_2 emissions from the proposed plant might be addressed.[228] In the public comment period held for the proposed plant, the Illinois EPA generally solicited comments from the public on its proposed action on the application for the proposed plant. As this comment and numerous other comments show, the public availed themselves of this opportunity to submit comments relative to status of CO_2 and other GHG under the PSD program. The Illinois EPA has considered these comments, as well as other comments that were submitted, and has responded to them in this Responsiveness Summary.

Incidentally, the Project Summary prepared by the Illinois EPA for this project did not "contemplate" sequestration of CO_2 in the manner implied by this comment. Rather, in describing the proposed plant, the Project Summary recognizes Power Holdings' stated desire to utilize the CO_2 from the plant, which would affect whether there is are discharge from the atmospheric vents on the acid gas removal units.[229] In addition, whether, when or how the CO_2 from the proposed plant is sequestered is not relevant to the current status of CO_2 under the federal PSD Program, as this is a legal matter.

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

---

[228] The situation of the Illinois EPA with respect CO_2 also seems to be readily apparent. Until the federal government, the Illinois legislature, or the Illinois Pollution Control Board provides differently, the Illinois EPA must conduct permitting in accordance with current laws and regulations, under which CO2 is not a regulated pollutant. Moreover, the Johnson Memorandum, which was issued in December 2008, was issued before the public comment period on the permit for this project began on January 17, 2009. Thus the USEPA's position on the status of CO_2 was clear. As the Illinois EPA administers the federal PSD program under a delegation from USEPA, the Illinois EPA's position was necessarily the same as the USEPA's.

[229] When describing the operation of the gasification block at the proposed plant, the Project Summary acknowledges, in passing, that CO_2 might be utilized rather than being vented to the atmosphere. "The main emission points from the gasification block during normal operation, if carbon dioxide (CO_2) from the gasification block is not otherwise utilized, would be the atmospheric vents from the AGR units. In addition to removing sulfur compounds from the raw syngas, which are sent to the sulfuric acid plants, the AGR units also remove CO_2 from the raw syngas. The CO_2 streams from the AGR units would pass through regenerative thermal oxidizers to control the carbon monoxide (CO) and volatile organic material (VOM) present in these streams, before they are vented. These oxidizers would also convert the remaining sulfur compounds present in these streams to sulfur dioxide (SO_2)." Project Summary, page 3.

LISTING OF SIGNIFICANT CHANGES BETWEEN THE DRAFT PERMIT AND THE ISSUED PERMIT

1. Findings 6(b): This finding, which documents consideration of the plant's impacts on Class I Areas, was revised to indicate that this aspect of the proposed plant's impacts was addressed with screening analysis. *This change was made in response to a comment indicating that a copy of a modeling analysis for impacts on Class I Areas was not contained in the record. The change is intended to clarify that this analysis was not a detailed modeling analysis, as this commenter expected to find, but a screening analysis.*

2. Condition 3.6(b)(ii): This new condition explains how compliance with annual limits set by the permit is to be determined during the first year (12 months) of operation. During this period, compliance with annual limits is to be determined on a cumulative-monthly basis, from the data for the current month and all preceding months. *This change responds to a comment that questioned how compliance with annual limits would be determined before there were 12 months of data as would be needed for compliance to be determined as a running total of 12 consecutive months of data. The new condition provides an approach that provides practical enforceability of annual limits during the first year of operation, with compliance determined on a monthly basis, based on the operation and emissions that have occurred. The first determination of compliance with annual limits is not "deferred" until 12 months after the plant began operation.*

3. Condition 4.1.5-2: This condition, which sets forth the requirements for the Startup Shutdown and Malfunction (SSM) Plans that must be developed and implemented for the gasification block, now makes references to various provisions of 40 CFR 63.6(e) "as adopted on April 20, 2006." *This change responds to a question about how the provisions of 40 CFR 63.6(e) would apply if certain provisions of 40 CFR 63.6 were vacated by the courts. To insulate the permit from the effects of any such vacatur, the permit now makes reference to a particular version of 40 CFR 63.6, that is, "as amended on April 20, 2006." April 20, 2006 is used for this purpose because 40 CFR 63.6 was last revised by USEPA on April 20, 2006, so it reflects the version of 40 CFR 63.6 that was applicable during the processing of this application.*

4. Conditions 4.1.6(a) and (b): In these conditions, which limit the emissions from the units in the gasification block in pounds per hour and tons per year, the limits for volatile organic material (VOM) were raised. *This change was made because methanol, which is both a HAP and VOM, was not accounted for in the VOM emissions limits that were included in the draft permit. This change will not increase permitted annual emissions of VOM from the plant, since other compensating reductions were made in the permitted VOM emissions of the superheaters, as made feasible as the issued permit does not allow syngas to be used as fuel in these units.*

5. Condition 4.1.6(a): This condition now includes limits on emissions of fluorides from the gasification block. *This change responds to a comment questioning whether the plant would be a significant project for emissions of fluorides and should be subject to PSD for fluorides. Emissions of* fluorides *are now explicitly limited to ensure that the plant is not significant for emissions of fluorides.*

6. Condition 4.1.6(b): In this condition, which sets limits on the emissions of the units in the gasification block that are controlled with flares, the limit for annual emissions total HAP was raised to 0.19 tons per year. *This change was made because emissions of carbonyl sulfide (COS), a HAP, were not accounted for in the limit for total HAP emissions in the draft permit, and must be accounted for in the issued permit. Note: COS is also a total reduced sulfur (TRS) compound, but the limit for TRS emissions correctly accounted for all TRS compounds and is unchanged.*

7. Condition 4.2.1: In this condition, which provides a description of the superheaters and auxiliary boiler, only use of natural gas (which includes both natural and synthetic natural gas) is discussed. In other words, use of "clean syngas" by the superheaters is no longer mentioned. *This change was made because the issued permit only allows use of natural gas as the fuel for the superheaters.*

8. Conditions 4.2.2(a)(i) and 4.2.2(b)(i): These new conditions have been added to specify that use of natural gas (which includes SNG) is an element of BACT for the superheaters and auxiliary boiler. *This change was made*

in conjunction with other changes to the permit made in response to a comment that questioned why natural gas was not required as BACT for these units. Note that the draft permit would have already restricted the auxiliary boiler to operation with natural gas.

9. Condition 4.2.3-2(c): This condition, which addresses the applicable state NOx emission standard (35 IAC 217.121(a)), now addresses both superheaters and the auxiliary boiler. *This change was made because only a single state standard for NOx emissions now applies to these units. This is because these units are all now restricted to use of only natural gas, so the same state emission standard applies.*

10. Condition 4.2.5(a): This condition, which addresses the fuel used in fuel combustion emission units at the plant (i.e., the superheaters and the auxiliary boiler), now limits the superheaters to use of natural gas. This change also allowed the condition to be simplified as both the superheaters and auxiliary boiler are now restricted to operation with natural gas. *This change was made in response to a comment that questioned why these units were not restricted to operation with natural gas or other clean fuels, rather than also being allowed to use syngas as fuel. Upon further consideration, the Illinois EPA concluded that it was appropriate to restrict the superheaters to use of natural gas. (The auxiliary boiler was already restricted to use of natural gas by the draft permit.)*

11. Condition 4.2.6(a): In this condition, which sets limits on the emissions from the superheaters, the limits set for different pollutants were lowered. *This change was made in conjunction with other changes to the permit to reflect operation of the superheaters with only natural gas.*

12. Conditions 4.2.6(a) and (b): These conditions, which set limits on the emissions from the superheaters and auxiliary boiler, now clarify that the limits set for PM address total emissions of particulate matter, including both filterable and condensable particulate. *This change was made to respond to a comment that observed that the PM limits that would have been set by the draft permit were not consistent with the air quality modeling that was conducted, as they only applied to filterable particulate. The change corrects this oversight, so that the emissions limits for PM match the modeled emission rates.*

13. Condition 4.2.7(a)(ii): This condition, which addresses emission testing of the superheaters and auxiliary boiler, now explicitly requires testing for emissions of condensable particulate matter. *This change was made in conjunction with changes to the PM emission limits for these units, as discussed above. In particular, it was realized that while Condition 4.2.7(b)(ii) specified a test method for condensable particulate, the preceding condition mandating testing for different pollutants did not list condensable particulate.*

14. Conditions 4.2.7-2 and 4.2.10(d)(iii): These conditions in the draft permit are not carried over to the issued permit. These two conditions required analysis of the composition of syngas and records of this analysis activity, respectively, as related to use of syngas as fuel in the superheaters. *This change was made in conjunction with other changes restricting the superheaters to operation with natural gas. As a result of this restriction, analysis of syngas is no longer necessary as related to its use as fuel, as would have been required by these conditions in the draft permit.*

15. Conditions 4.7.2(b)(i), 4.7.3-1(b) and 4.7.7-1(b): These conditions, which address requirements of the New Source Performance Standards (NSPS) for Coal Preparation Plants, 40 CFR 60, Subpart Y, that would apply to coal handling operation at the plant, now address the current requirements of 40 CFR 60 Subpart Y for new units constructed after April 28, 2008. *This change addresses revisions to this NSPS that USEPA finalized after the draft permit was prepared.*

16. Condition 4.9.1: This condition, which describes the components or equipment from which leaks may occur with emissions of VOM and HAPs, now explains that leaks and emissions could occur if CO_2 is compressed. *This change was made in response to a comment that questioned whether leaks of this type were addressed in the application and by the permit. The change makes clear that leaks of this type would be addressed by Section 4.9 of the permit, which addresses leaking components and their emissions.*

17. Condition 4.9.3(c) and (d): These new condition was added to specify that certain types of equipment and components be used at the plant to prevent leaks and associated emissions. Condition 4.9.3(c) specifies that

pumps in light liquid service be leakless design pumps. Condition 4.9.3(d) specifies that closed loop sampling systems be used. *This change was made in response to comments that to observed that the emission calculation for leaks in the application had not accounted for any leaks and emissions from these types of components. These new conditions act to prevent emissions from these type of components as leakless types of equipment must be used.*

18. Attachment I (Finding 3): Various changes were made to Attachment 1, which summarizes the potential annual emissions of the proposed plant. *These changes were made to account for changes in the permitted emissions of certain units, as already discussed, and to correct errors in this tabulation in the draft permit.*

    a. The potential VOM emissions for the gasification block and the superheaters and auxiliary boiler were changed consistent with the changes in the permitted VOM emissions of these units (See Changes 4 and 11), with no change in the total VOM emissions of the plant.

    b. The emissions of the superheaters and the auxiliary boiler and the total emissions from the plant were lowered to account for the reductions in permitted emissions due to restricting the superheaters to use of natural gas. For example, the SO_2 emissions of the superheaters were reduced from 4.3 to 3.8 tons per year.

    c. The tabulation for SO_2 was corrected to account for a summation error in the draft permit. That is, in the draft permit, the total SO_2 emissions were incorrectly stated as 512.4 tons/year, when the total should have summed to 516.7 tons/year.

    d. The emissions of "total HAPs" (i.e., the total of all HAPs, combined) from the gasification block during startup, shutdown and malfunction were raised to address an error in the draft permit. In particular, the emissions of methanol and the emissions of "other HAPs" (i.e., combined HAPs other than methanol) were incorrectly summed in the draft permit. However, the plant's total emissions of total HAPs will still not be higher than was indicated in the draft permit.

    e. The tabulations for other HAPs and total HAPs from the plant were changed to correct errors in the draft permit, with no increase in total emissions of the plant, in part due to reductions in the HAP emissions of the superheaters with use of only natural gas. In the draft permit, individual entries were incorrectly summed. The emissions of "other HAPs" from the sulfuric acid plant were also expressed differently than for other units, with emissions of "any single HAP other than methanol" provided, rather than "the combined emissions of HAPs other than methanol."