ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
BUREAU OF AIR

June 2007

Responsiveness Summary for Public Questions and Comments on the Construction Permit Application from Big River Resources, LLC for an Ethanol Plant in Galva, Illinois

Site Identification No.: 073045AAV
Application No.: 06070047

TABLE OF CONTENTS

Introduction 2
Description of the Proposed Plant 2
Comment Period and Public Hearing 2
Availability of Documents 3
General Comments with Responses by the Illinois EPA 3
Comments on the Draft Permit with Responses by the Illinois EPA 10
Other Comments Concerning the Proposed Plant 50
For Additional Information 51

INTRODUCTION

Big River Resources, LLC (Big River Resources) has applied for an air pollution control construction permit to build a fuel ethanol production plant in the community of Galva in Henry County.

Upon review of comments received during the public comment period and final review of the application, the Illinois Environmental Protection Agency (Illinois EPA) has determined that the application meets the standards for issuance of a construction permit. Accordingly, on June 18, 2007, the Illinois EPA issued a permit to Big River Resources to construct the proposed plant. The plant must be constructed and operated in accordance with all applicable regulations and the terms and conditions of the issued permit.

The issued permit includes a number of additional requirements for the proposed plant compared to the draft permit, as well as various clarifications to conditions, based on public comments. In particular, the issued permit contains additional limitations on certain operations and additional requirements for monitoring and recordkeeping to assure that the proposed plant would not be a major source of emissions under the federal rules for Prevention of Signification Deterioration (PSD), 40 CFR 52.21.

DESCRIPTION OF PROPOSED PLANT

Big River Resources has proposed to construct a plant to produce ethanol from corn. The plant would be designed to have a nominal capacity of 100 million gallon per year, with the ability to actually produce up to 110 million gallons of ethanol per year. The denatured ethanol produced by the plant would be used as motor vehicle fuel. When added to gasoline, ethanol is an octane enhancer and oxygenated fuel additive, which reduces hydrocarbon and carbon monoxide emissions in vehicle exhaust. The plant would produce ethanol by batch fermentation of ground corn, followed by processing to separate out and purify the ethanol. The plant would also produce animal feed from the stillage material remaining after the fermentation process. The plant would have facilities to receive raw material (grain) and ship products (fuel ethanol and feed) by both truck and rail. Natural gas would be used as the fuel for the plant.

COMMENT PERIOD AND PUBLIC HEARING

The Illinois EPA Bureau of Air evaluates applications and issues permits for 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 Big River Resources' application, the Illinois EPA Bureau of Air made a preliminary determination that the application for the proposed plant met the standards for issuance of a construction permit and prepared a draft permit for public review and comment.

The public comment period began with the publication of a notice in the Kewanee Star Courier on February 10, 2007. The notice was also published in this newspaper on February 17 and 24, 2007. The notice was also published in the Galva News on February 14, 21 and 28, 2007

A public hearing was held on March 28, 2007 at Blackhawk College, 1501 State Highway 78 in Kewanee to receive oral comments and answer questions regarding the application and draft air permit. The comment period closed on April 27, 2007.

AVAILABILITY OF DOCUMENTS

The permit issued to Big River Resources and this responsiveness summary are available on the Illinois Permit Database at www.epa.gov/region5/air/permits/ilonline.htm (please look for the documents under All Permit Records (sorted by name), State Construction Permits). Copies of these documents may also be obtained by contacting the Illinois EPA at the telephone numbers listed at the end of this document.

GENERAL COMMENTS WITH RESPONSES BY THE ILLINOIS EPA

1. How are the emissions of the proposed plant determined? For example, are emissions estimated by using emissions factors published by USEPA in its *Compilation of Air Pollutant Emission Factors*, AP-42?

The projected emissions of the proposed plant generally reflect information in the application supplied to Big River Resources by ICM, the designer of the proposed plant. The information is based on a variety of supporting information and documentation. The projected emissions for the proposed plant reflect the designer's experience with similar emission units at other plants, including the results of emissions testing, and performance guarantees provided by suppliers of air pollution control equipment for the proposed plant. Emission factors and emission calculation methodologies published by USEPA in AP-42 are used to estimate emissions for certain operations at the proposed plant, such as roadways and flares, for which emission testing is impractical and alternative approaches are commonly used to determine emissions.

2. Will there be problems with air quality once this plant is built? There are people in the area that have severe respiratory problems.

The proposed plant is located in a rural attainment area for all criteria air pollutants. In Illinois' rural attainment areas, the construction of a new minor source does not pose a concern for its impact on ambient air quality.

3. Will the plant be odorous in the surrounding area? I'm very concerned about odors from the proposed plant because I would live close to the site of the proposed plant.

The emissions from the proposed plant will be well controlled using emission control equipment that is now standard at new fuel ethanol plants. This equipment, which includes a scrubber for

the fermenters and oxidizer systems for the distillation units and feed dryers, will also control emissions of odors from the plant. These units must also be equipped with stacks that are high enough above structures to prevent downwash and enable good dispersion of emissions.

If there are nuisance odors from the plant, the Illinois EPA would take action to ensure that the plant was taking appropriate steps to eliminate such odors. The construction permit does not excuse Big River from the obligation to undertake further actions to control emissions if needed to eliminate a public nuisance due to odors from the plant. If a problem would occur, the Illinois EPA would review the adequacy of the plant's proposed response to the problem, including any additional equipment that the plant would install, to confirm that the proposed response has been developed to adequately and appropriately respond to the problem.

4. Will the odor from the plant be like the odor from the ethanol plant when you drive through downtown Peoria or what is the odor going to be like?

The ethanol plant near downtown Peoria is not an appropriate comparison for the proposed plant. That plant is an "existing" ethanol plant that was built before the era of modern emissions controls. At the present time, only a portion of the exhaust from the feed dryers at that plant is controlled by a thermal oxidizer, with the remainder of the exhaust still required to be controlled pursuant to a joint federal-state consent decree with the operator of the plant.

Based on experience with other modern ethanol plants, if equipment at the plant is properly designed, operated and maintained, the proposed plant should not be a source of nuisance odors. While some odor may be detectable immediately downwind of the plant, the extent of such odor will normally be very limited. Odors will not normally be detectable outside this area and the plant will not interfere with the day-to-day lives of the people living nearby.

5. What should I do if I am bothered by odors from the plant?

If you are bothered by odors from the plant, you should inform the Illinois EPA. It is important that the Illinois EPA be notified of problem odors so that it can investigate to determine the cause of the problem, review the actions being taken by the plant, and develop an appropriate response by the Illinois EPA. Complaints can be made by telephone, letter or e-mail. The telephone of the local Regional Office of the Illinois EPA in Peoria is 309-694-5461. The Internet address for submitting a complaint is http://www.epa.state.il.us/pollution-complaint/.

The Illinois EPA would also encourage you to directly contact the plant. In particular, if odors are due to a malfunction or upset, the plant may be able to provide an immediate explanation of what has happened. A call to the plant can also allow plant personnel to initiate their investigation during the period when odors are being experienced, rather than attempting a more challenging investigation several days after the event.

6. How quickly would the Illinois EPA get back to a person who filed a complaint? Does it take days, weeks or months? How long would it take to rectify the problem?

The speed of the response and any remedial action, if needed, would depend upon the situation. Certainly, if the problem is due to an equipment malfunction, action should occur within hours. If the problem reflects a chronic or deteriorating problem with equipment, the timing would be longer and depend on the particular situation.

7. Will the emissions from the plant affect wildlife?

As the emissions from the plant would not pose a concern for air quality, they also would not pose a concern for wildlife.

8. Is the Illinois EPA going to do all it can to protect our health and our welfare?

The permit for the proposed plant rigorously addresses the emissions from the proposed plant, in a manner that is consistent with applicable regulations and the general legal authority of the Illinois EPA. The permit contains a variety of requirements for the various units at the plant to ensure that emissions are properly controlled. Emission testing must be conducted on significant units at the plant after construction to verify that emissions at maximum throughput and normal operating conditions will be within the limits established by the permit. Units must also be promptly retested upon written request by the Illinois EPA. Continuous emission monitoring is required for the oxidizer/boiler systems for NOx. Additional emissions monitoring for CO is required unless emission testing shows that these systems normally meet the applicable limits with a respectable compliance margin. A variety of operational monitoring is required for the control equipment at the plant to verify proper operation. Big River will also have to keep operating records that will allow Big River and the Illinois EPA to verify whether the plant is operating in compliance and identify any period when a unit may be exceeding applicable emission limits or other requirements.

9. How often would the Illinois EPA conduct air pollution inspections of the plant?

Inspections would usually be performed about every two years but would be much more frequent if needed to address a particular concern or problem. Inspections are also routinely made in response to public complaints about a source.

10. What are some of the potential problems with air quality that might come from this plant, which local residents should be concerned about?

As previously explained, emissions of the plant should have minimal effects on local air quality for different pollutants. Likewise, as equipment at the plant is properly designed, operated and maintained, the proposed plant should not be a source of nuisance odors. The key concern for the plant is lapses in control of emissions as they could affect odors, as could occur from a breakdown or other failure of equipment to operate properly. To address this, the permit for the plant requires recordkeeping to document proper operation and maintenance of emission control equipment and reporting of deviations to the Illinois EPA, including immediate reporting for any significant upsets of the control equipment.

11. Would the emissions of the plant occur at a constant rate throughout the day or would they be higher at certain times?

The units at the plant engaged in the production of ethanol are designed to operate at a steady state, so would generally produce emissions at a constant rate. For fermentation, which is a batch operation, this is because the timing of the operation of the seven separate fermentation tanks is staggered, which stabilizes the overall rate at which emissions are generated.[1]

The units at the plant engaged in the receiving of raw materials and shipping of products would be idle most of the time. They would only operate when trucks or railcars were making deliveries of grain or picking up loads of ethanol or feed and the actual operating rate would vary based on how quickly material was handled.

12. Under what conditions are emission units operated when emissions testing performed?

Emission testing has to be conducted during operating conditions that would be representative of maximum emissions. This involves operation of process emission units in the maximum range of operation, so that they are generating emissions at the maximum rate. It involves operation of control devices at the lowest level of operating parameters at which the devices would normally be operated, so as to provide the minimum level of control.

13. Are there specific regulatory requirements for odor? In particular, is there a quantitative approach to measuring odor and acceptable levels of odors in the air? Or are the requirements for odor subjective, especially as individuals respond differently to various odors?

Unlike the provisions for specific air pollutants, Illinois does not have rules that set numerical standards or other specific requirements for odors. Instead, odors are prohibited by state laws and rules that generally prohibit sources from causing air pollution. These provisions prohibit a source from causing or contributing to the presence of contaminants in the atmosphere that unreasonably interfere with the enjoyment of life or property (as well as to the presence of contaminants in the atmosphere that are injurious to human, plant or animal life). While these provisions do not prohibit any odors, they do require sources to take reasonable measures to control odors that negatively affect nearby resident. Moreover, as technology is now available that can effectively control odors from new ethanol plants, this requires that such technology be installed at ethanol plants and be properly operated and maintained.

14. Will there be a wastewater discharge from the proposed plant.

The proposed plant is designed to reuse all process water at the plant, so that there would not be any discharge of process wastewater. In general terms, process water recovered from the back end processes at the plant would be returned to the front end processes at the plant.

---

[1] The staggered operation of the individual fermenters is inherent in the design of the plant. This is because the other processes rely on the staggered operation of the fermenters so that they can operate at a steady rate. For example, the distillation area is designed to complete the processing of the finished beer output of a single fermenter in the time period before the next fermenter completes fermentation. Likewise, the fermenters themselves are designed so they can be "turned around," i.e., emptied, cleaned and refilled with mash, in this same time period, so that one and only fermenter is undergoing turnaround at any time.

Separate from process wastewater, the proposed plant will have a discharge of non-contact water from the cooling tower. This water doesn't come into direct contact with corn or ethanol. It is actually well water that is cycled through the cooling tower so the mineral content builds up. The wastewater is this high-mineral water.

15. How will wastewater be handled at the plant? Will the plant discharge wastewater? Does Big River need to get a permit for this?

Big River has explained that the proposed plant will be designed for zero discharge of process wastewater. Essentially, process wastewater recovered by units at the back end of the plant would be returned to units at the front end, rather than being discharged as wastewater.

Separate from process wastewater, the proposed plant will have a discharge of non-contact water from the cooling tower, for which Big River will have to obtain an appropriate wastewater discharge permit or approval. This wastewater stream will be managed to maintain the level of dissolved solids within the limits set by the wastewater permit or by Galva, depending on whether the plant has its own discharge, , or wastewater would go to Galva's wastewater treatment plant.

16. Where will the discharge of wastewater go? Will the plant have its own wastewater treatment facility? If Big River is planning on sending its wastewater to Galva's wastewater treatment facility, that facility currently does not have the capacity to handle the flow from the proposed plant and probably would have to be expanded. Would that be at the public expense or would that be at the expense of Big River?

Big River has indicated that it has not yet completed its plans for this discharge, for which Big River will have to obtain an appropriate wastewater discharge permit. This wastewater stream will be managed to maintain the level of dissolved solids within the limits set by the wastewater permit.

17. Where will the stormwater from the plant go and will it be treated before discharge?

The standard approach to stormwater management at industrial plants, as will be used at this plant, is to collect potentially contaminated storm runoff in a retention basin or pond, to allow treatment of the water if needed before discharge.

18. How deep would the wells be that supply water to the plant? I have a 420 foot well. Will the new wells at the plant affect my water supply or the wells of other people in the area?

Big River has indicated that water for the plant would come from very deep wells, in excess of 2000 feet. (The plant would not obtain water from a pipeline constructed to the Illinois River, as some have heard.) The depth of the new wells for the plant means that there should be no effect on residential wells that draw water from different aquifers that are closer to the surface.

19. As a neighbor, who would live close to the plant, I am concerned about noise.

Ethanol plants have not posed a particular concern for noise. ICM reports that Big River's West Burlington plant is one of the few plants at which it has experienced a noise problem. The problem was due to an unbalanced fan and was readily corrected once the cause was identified.

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

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

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

Truck traffic for the plant would continue to travel on designated truck routes, like the grain trucks that are currently delivering grain to the existing elevator that will serve the plant. While the proposed plant would increase truck traffic, the amount of such increase will be mitigated as output from the plant travels by rail. 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.

22. Would Galva's local volunteer fire department be able to handle a fire or other emergencies or incidents at the plant?

Big River must 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. In this regard, the plant is similar to other industrial plants that are located in Illinois' rural communities.

Fire preparedness plans routinely address the capabilities and appropriate roles of local response personnel. They also address the resources that would be available on a regional basis to respond to incidents, as can be especially important for plants located in small rural communities. Fire preparedness planning is assisted by the safety codes enforced by insurance companies. These codes require that the plant be developed and maintained to minimize the risk of fire and to allow any fire that might occur to be safely contained, controlled and extinguished. For example, the plant must maintain a reserve supply of water for the sprinklers and hydrants at the plant. An adequate supply of fire fighting foam must also be kept at the plant, as is important for fighting certain types of fires. An emergency fire water pump is required so that the plant water system can operate during a power outage. These measures contribute to the good fire safety record of ethanol plants.

23. 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. I wonder whether I should sell my property because of the proposed plant.

The Illinois EPA does not have a role in these aspects of the proposed plant. Under Illinois law, these aspects of proposed plants are the responsibility of local government. Galva and Henry County have the responsibility of addressing the effect of industrial development on property values through zoning and land use management planning, through building permits and

through other local approvals required for construction, and through their agreements with project developers.

24. I don't want my taxes to go up to pay for new water or sewer lines or other improvements to support the proposed plant. My taxes are high enough now and many people in our community are on fixed incomes.

The construction of the proposed plant will be privately financed. Any expenditure by local government to provided services to the plant should either be directly or indirectly reimbursed, through user fees or increases in local tax revenues. For example, even if the local school district will not receive property taxes from the proposed plant for a period of time, the plant would act to support the local tax base.

25. What level of education will be required for the jobs at the proposed plant? Will college degrees be needed or will a high school diploma be enough?

Big River has indicated that it expects very few people at the plant to have college degrees. While there will be some technical jobs at the plant, they will only require appropriate vocational training or job experience.

26. Is there going to be too much competition among new ethanol plants (new plants are proposed at locations other than Galva), so there is a chance that the Galva plant, which taxpayers would pay for, closes and becomes an eyesore?

An economic analysis of proposed ethanol plants has been conducted by the Illinois Corn Growers Association, as discussed at the public hearing by Rodney Weinzierl, the association's executive director. This analysis found that northwestern Illinois can support a number of new plants distributed across the area without undue economic competition between them.

27. A federal lawsuit, in which the Illinois EPA was also named as a defendant, was recently filed against the permitting of a fuel ethanol plant that is proposed for Hennepin. Will that lawsuit affect the timeliness of the issuance of a permit for this project?

This lawsuit is a separate matter from the project proposed by Big River and did not affect the timing of the issuance of this permit. Incidentally, the plaintiffs in this lawsuit recently filed a motion to voluntary dismiss this lawsuit.

28. For purposes of the PSD rules, fuel ethanol plants, like the proposed plant, are currently regulated as "chemical process plants." Although a revision to the federal PSD rules by USEPA will shortly take effect so that ethanol plants that process corn by fermentation, like the proposed plant, would no longer be considered "chemical process plants," this change will not alter the PSD major source threshold for the proposed plant. This plant will continue to be subject to the PSD major source threshold of 100 tons per year. This is because the plant would also be in another listed source category for which the 100 tons per year threshold applies, i.e., a source with fossil-fuel boilers with a total heat input capacity totaling more than 250 million Btu/hour. In addition, fugitive emissions would still have to be considered when determining whether the proposed plant is a major source.

In particular, independent of whether ethanol plants are "chemical process plants," ethanol plants of the size of the proposed plant have necessarily been considered as having the primary pollutant-emitting activity of "generation of steam." For purposes of applicability of the PSD rules, the upstream and downstream emission units associated with the boilers at the proposed plant cannot be isolated or distinguished as a separate stationary source from the boilers. The purpose of the boilers is to make steam for use in process operations at the plant and to control emissions from certain processes. Accordingly, the entire plant remains subject to the 100 tons per year PSD major source threshold. The emission units at the plant other than the boilers are necessarily in the same "industrial grouping" as the boilers because the production of ethanol is dependent upon a supply of steam and the PSD rules define a "stationary source" to include "…all of the pollutant-emitting activities which belong to the same industrial grouping..." 2a

Moreover, ICM has stated in correspondence with USEPA that the gas-fired dryers and the gas-fired oxidizers-boilers at the ethanol plants that it designs are integrally and inextricably linked by the steam needs of plants, which go beyond the role of the oxidizer-boilers in controlling emissions:[2] This further demonstrates that all the process emission units at the proposed plant are the same industrial grouping as the fossil fuel boilers at the plant, so that the proposed plant will remain subject to the 100 ton PSD major source threshold.

As observed in this comment, certain revisions to the federal PSD rules that may affect the PSD major source threshold for fuel ethanol plants are not yet effective. Accordingly, this comment is not relevant to the issuance of this construction permit, which is based on the PSD rules at the time the permit was issued. Since the comments is not relevant to the draft or issued permit, the Illinois EPA has not provided a substantive response to this comment.

Moreover, this comment is appropriately directed to USEPA in the context of its rulemaking revising the federal PSD rules. This comment argues that the proposed ethanol plant is appropriately classified under the federal PSD rules as being in the listed source category of "fossil fuel boilers," rather than being in an unlisted category, such as "fuel ethanol plants." This directly relates to the USEPA's revisions to the PSD rules, as those revisions dealt with the appropriate source category for ethanol plants. Accordingly, the Illinois EPA has forwarded a copy of this comment to USEPA for its consideration and response as it deems appropriate.

COMMENTS ON THE DRAFT PERMIT WITH RESPONSES BY THE ILLINOIS EPA

29. As set forth in the application, the proposed plant would have two boilers, each with a maximum physical input of natural gas fuel of 122 million Btu/hour.[3] However, even though the draft permit would by enforceable condition limit the natural gas heat input of each boiler to no more than 122 million Btu/hour, the total heat input of these units by operational design

---

[2] ICM states in a memorandum sent to USEPA that the "The heat from the dryer (purpose to produce DDGS) and TO (purpose to destroy VOCs per EPA's January 8, 2003 Badger State Ethanol Memorandum) are both heat sources needed to create steam for the plant in the HRSG unit." (See Attachment 19).

[3] The boilers at the proposed plant are slightly smaller that boilers that ICM would typically installa at a plant like the proposed plant. ICM has indicated in correspondence to USEPA that its boilers are actually typically designed for 125 million Btu/hour of heat input.

is more than 250 million Btu/hour. The oxidizers will control process gas streams that contains significant amount of VOM. The heat input from this VOM will be more than enough to take the total heat input of the oxidizers over 250 million Btu/hour.[4] In this regard, for purposed of PSD, "…heat input means the total gross calorific value … of all fuels burned." 40 CFR 52.01(g). Thus, the uncontrolled VOM emissions from the dryers are "fuels" that contribute heat input to the oxidizers. Therefore, the oxidizer-boilers have more than 250 million Btu/hour of heat input from direct fuel inputs, even without considering any heat input from the dryer burners that is carried over to the oxidizers.[5]

This comment is also not relevant to this proceeding given the timing of permit issuance. Accordingly, a substantive response will not be provided, as discussed above. In addition, the issue posed by this comment, i.e., how should the heat input of the boilers at the proposed plant be calculated for purposes of determining whether they are in a listed source category, again relates to the USEPA's revisions to the PSD rules, which dealt with the appropriate source category for fuel ethanol plants. Accordingly, a copy of this comment has also been forwarded to USEPA for its consideration.

30. The draft permit sets limits on the emissions that are just below the thresholds at which the plant would be considered a major source.

This is correct. However, Big River Resources has conservatively applied for emission limits that are believed to generally reflect the emission guarantees that it has obtained for the proposed plant. It is expected that the actual emissions of the plant would be below these numbers. As an example, oxidizers can achieve higher efficiencies in practice than the minimum efficiency required by the permit and higher efficiencies in practice would lower the actual emissions from the plant.

31. There are serious problems with the determination of potential emissions for a number of operations at the proposed plant, as addressed in separate detailed comments. If the potential emissions of the proposed plant for any criteria pollutant are 100 tons per year or more, a permit may not be issued since the proposed plant has not undergone review under the federal rules for Prevention of Significant Deterioration (PSD), 40 CFR 52.21, as is required for a proposed major source. Similarly, if the potential emissions of any single hazardous air pollutant (HAP) from the plant are 10 tons per year or more a permit can not be issued since the plant has not undergone a case-by-case determination of Maximum Achievable Control technology (MACT) for emissions of HAPs.

This is a critical issue because the margins between the permitted emissions for the proposed plant and the 100 ton/year major source threshold are very small for most pollutants. In particular, based on the summary of emissions in Table 1 of the draft permit, these margins are 2.61, 2.7, 4.02, and 5.56 tons per year for volatile organic material (VOM), carbon monoxide (CO), particulate matter (PM) and nitrogen oxides (NOx), respectively. The

[4] Extrapolating from data from smaller plants (Attachment 12), the exhaust from the feed dryers at the proposed plant dryers would be expected to have a total of about 1760 lbs of VOM per hour before control. Based on other data (Attachment 17), the heat input from the VOM in the dryer exhaust would be at least 11 million Btu/hour.

[5] The oxidizers also receive "heat input" from the output of the feed dryers, which in total have 180 million Btu/hour of natural gas fired burner capacity.

detailed comments for certain units at the proposed plant show that the potential emissions of those units have been underestimated. When these underestimates are considered, it is clear that the proposed plant will be a major source for certain pollutants. In addition, for the specific units for which emissions have been underestimated, these emission calculations constitute errors in the application.

The "margins" between the permitted emissions of the plant and the 100 ton/year major threshold source are all at least 2.0 tons. This is an adequate margin given the nature of the underlying emissions calculations and the provisions of the permit that act to ensure that the proposed plant will not be a major source of emissions. The various comments on specific operations do not identify fundamental flaws in the evaluation of the emissions of the proposed plant, whose correction results in the proposed plant being a major source.

32. If the emissions of a particular emission unit as initially tested or monitored are higher than expected, would the plant have to reduce the amount of ethanol it produces to stay below the major source threshold?

In the event that emissions of a particular emission unit are initially higher than expected, one possible response would be to reduce ethanol production. However, it is more likely that Big River Resources would take corrective actions to reduce the emissions of the responsible unit, with adjustments or repairs to the installed emission control technology on the particular unit. The situation could also be addressed by "reallocation" of emissions from other units that perform significantly better than planned or by implementation of additional measures or equipment to further control emissions. Big River Resources could manage the initial operation of the plant while these actions are being carried out so that the plant's actual emissions never exceed the major source threshold.

33. Measurements of emissions by USEPA Method 18 should be required to address at least 20 specific organic compounds, including acetaldehyde, acetic acid, ethanol, formaldehyde, formic acid, furaldehyde, methanol, glycerol, lactic acid, butanol, acrolein, isoamyl alcohol, ethyl acetate, succinic acid and isoamyl acetate. These compounds are recognized byproducts of fermentation. Several of these compounds have higher boiling points, so that they may be retained in stillage materials until they are subjected to elevated temperatures in the feed dryers.

While emission measurements for many of the compounds listed in this comment will be made as part of VOM emission testing, the extent of such testing is a matter that is appropriately resolved shortly before testing, as part of the approval of a test plan by the Illinois EPA. This is because USEPA may continue to evaluate and refine its guidance for testing of VOM emissions at ethanol plants and other grain processing plants. However, the general effect of this USEPA guidance is also clear, as it requires VOM test results to be properly "adjusted" to accurately reflect the actual mass of VOM emissions.

Grain Handling and Milling (Condition 2.3)

34. The application does not include technical details for the design of the grain receiving area or

the associated fugitive emissions collection system, including the effective grate area of the dump-pit and the amount of aspiration air. This is unacceptable because it is not possible to know if the design of these systems will properly and effectively collect fugitive emissions.

New grain receiving operations can be readily designed and constructed to control PM emissions. The permit requires that the PM emissions from grain receiving at the proposed plant not exceed 5 percent opacity. This sets the "specification" for control of PM emissions from the grain handling operations, which the operations and associated control devices must be designed, constructed and operated to meet. Even if the design of the proposed operation had been completed and details of the design submitted in the application, review of that design data for the operation would not excuse Big River Resources from complying with the performance specification for operation established in the permit.

35. The baghouse for grain handling operations, which has a capacity of 48,000 SCFM, serves other grain handling operations beside the receiving area. The application does not contain information on the amount of aspiration air to each operation or information on baffles and other control measures on each operation. Without this information, one cannot ensure that the system is designed to provide 95% collection efficiency, as relied upon in calculating PM emissions. Any increase in the size of the baghouse to assure effective control of emissions or failure of the fugitive emission collection system to properly function would threaten to push the plant's PM emissions over the major source threshold. The application should be considered incomplete until these details for the design of the control system are provided.

As explained above, the grain handling operations can be readily designed to achieve effective control of fugitive PM emissions. The receiving of grain at the proposed plant is the only operation for which such emissions pose any particular concern. Once grain has been received, operations can be readily enclosed so as to allow effective capture of PM emissions. The capacity of the baghouse for grain handling operations provided in the application, 48,000 SCFM, should be ample for effective control of emissions.

36. The construction permits issued to Patriot Renewable Fuels in Annawan (Patriot) and Marquis Energy in Hennepin (Marquis) included the following provision, which was not present in the draft permits, that modifies how USEPA Method 5 may be used to test PM emissions.

> For emission units for which the average stack gas temperature is less than 250 ºF, such as grain handling operations, but not including boilers, testing may be conducted at actual stack gas temperature without heating of the probe or filter holders. (Condition 3.1-1(b) Note a)

While it is reasonable to allow an unheated probe if USEPA Method 5 testing is carried out carefully with respect to collecting particulate from probe washing, this condition does not curb an unacceptable exercise of discretion by the emission testing personnel provided by Method 5 procedures when testing is conducted with an unheated probe. In particular, the following provisions of Method 5 allow problematic source testing at the primary or sole discretion of emission testing personnel:

> 8.1.3 Desiccate the filters at 20 ± 5.6 ºC (68 ± 10 ºF) and ambient pressure for at least

> 24 hours. Weigh each filter (or filter and shipping container) at intervals of at least 6 hours to a constant weight (i.e., < 0.5 mg change from previous weighing). Record results to the nearest 0.1 mg. During each weighing, the period for which the filter is exposed to the laboratory atmosphere shall be less than 2 minutes. Alternatively (unless otherwise specified by the Administrator), the filters may be oven dried at 105 ºC (220 ºF) for 2 to 3 hours, desiccated for 2 hours, and weighed. Procedures other than those described, which account for relative humidity effects, may be used, subject to the approval of the Administrator. (USEPA Method 5 - Section 8.1.3)
>
> Alternatively, the sample may be oven dried at 104 ºC (220 ºF) for 2 to 3 hours, cooled in the desiccator, and weighed to a constant weight, unless otherwise specified by the Administrator. The sample may be oven dried at 104 ºC (220 ºF) for 2 to 3 hours. Once the sample has cooled, weigh the sample, and use this weight as a final weight. (USEPA Method 5 - Section 11.2.1)

For probe washings, Method 5 provides the following:

> NOTE: The contents of Container No. 2 as well as the acetone blank container may be evaporated at temperatures higher than ambient. If evaporation is done at an elevated temperature, the temperature must be below the boiling point of the solvent; also, to prevent "bumping," the evaporation process must be closely supervised, and the contents of the beaker must be swirled occasionally to maintain an even temperature. … (USEPA Method 5 - Note after Section 11.2.4)

During PM emission testing in which the front half of the sampling train is not heated according to procedures set forth in USEPA Method 5, with measurements made in a lower temperature flue gas, what would otherwise be condensible particulate that would normally be collected in the back half of the sampling train may be deposited on the filter and in the probe. The cited provisions of USEPA Method 5 give emission test personnel discretion for unsupervised decisions in favor of oven treatment for filters and thermal treatment of probe washings. With an unheated sampling train, such discretion for sample catch processing may cause unaccounted losses of the condensible particle deposited in the front half of the sampling train. Accordingly, to avoid loss of PM sample, with resulting low measurements of PM emissions, the permit should not give testing personnel discretion as to methods used to treat filters and probe washings.

The Illinois EPA has not modified USEPA Method 5, as implied by this comment. Rather, the Illinois EPA has relied upon relevant provisions of the federal New Source Performance Standards (NSPS) for Grain Elevators, 40 CR 60 Subpart DD. In particular, for grain handling operations, as addressed by the condition, 40 CFR 60 303(b)(1) provides that "… the probe and filter holder shall be operated without heaters." In this regard, USEPA Method 5 accommodates testing at different temperatures based on the particular application of the test method. The comment also presumes that the selection of drying method for the various collected PM samples, whose purpose is to remove moisture from the sample, would significantly affect the measurement that is made. For example, the back half catch from a PM sampling train must also be dried when determining condensible PM emissions. The comment also overlooks the role of the Illinois EPA in supervising the conduct of emission tests. Finally,

this comment presumes that condensible PM emissions are present in the exhaust from grain handling operations. However, the reported presence of condensible PM emissions may be an artifact of testing conducted with a probe and filter heated to approximately 250 ºF (or of reactions that occur in the back half of the sampling train that would not otherwise occur in the atmosphere).

37. Condition 2.2.7 in the draft permit, which addresses emission testing for grain handling and milling operations, contain the words "as requested" which suggests that emission testing is not mandatory. This wording should be changed to eliminate any suggestion that emission testing is only being requested, but is not required.

The conditions of the issued permit do not include the language from the draft permit addressed by this comment, which could easily have been misunderstood.

38. If Big River Resources may accept shipments by straight truck (e.g., shipments directly from local farmers), PM emissions from straight truck loading must be addressed in the emission calculations and physical limits on potential emissions from the plant. This is because the calculations for fugitive emissions from grain receiving are based on the factor for uncontrolled emissions for grain delivery by hopper truck (from AP-42 Section 9.9.1, Grain Elevators) and 95 percent control from choke flow. However, the draft permit would not limit truck delivery of grain to the plant to hopper trucks, prohibiting delivery by straight trucks. Without such a condition, the plant can also accept delivery of grain by straight trucks, since straight trucks are still in use to transport grain. Since the emissions calculations do not address delivery of grain by straight trucks, any grain deliveries by straight trucks could push the plant over the major source threshold for PM.

    In response to a similar comment made in the permit proceeding for Marquis, the following condition was included in the issued permit:

    Grain from "straight trucks" (as distinguished from hopper bottom trucks) shall only be received if the grain receiving operation for such trucks is equipped with quick closing doors and an aspirated dump pit. (Condition 2.3.5(b) of the Marquis permit)

    However, this condition does not satisfy the basic need to limit the potential fugitive emissions from grain receiving. The uncontrolled emission factor for receiving of grain by straight trucks is 0.18 lb/ton, over five times higher than the factor for hopper trucks, 0.0035 lb/ton. It is not sufficient for the permit to specify some control measures as a contingently applicable requirement if the plant chooses to receive some grain from straight trucks. The measures specified in the Marquis permit, i.e., an aspirated pit and quick closing doors, are not capable of achieving the same 95% control achieved for hopper truck deliveries with choke flow. "Quick closing doors" cannot pass muster as a valid technique to provide all needed control to achieve the minimum 95% control efficiency for hopper loading for the higher uncontrolled emissions from straight truck loading. Under Illinois EPA's approach both hopper and straight truck unloading would utilize aspirated dump pits for receiving grain. Accordingly, the "extra control" to manage the dramatically higher emission rate with straight truck unloading would have to be achieved by the "quick closing doors." However, quick closing doors cannot control any fugitive emissions from straight truck loading while

such loading is actually occurring since the doors to the dump pit must remain open to receive the grain.

Any emissions from grain received by straight trucks must be fully characterized, which has not yet happened. The permit must specifically address the proportion of deliveries between hopper and straight trucks or otherwise limit the number of such straight grain truck deliveries. Without such emission characterizations and enforceable physical limits on the potential emissions, PM emissions from grain receiving would exceed targets set from emission calculations based entirely on hopper trucks. This could also cause the plant's PM emissions to exceed the 100 ton per year major source threshold.

The issued permit includes the condition from the construction permit for the proposed Marquis plant quoted by this comment. The purpose of this condition is to require that the emission rate, in lbs/ton, for uncaptured PM from any grain received at the plant from straight trucks does not exceed the emission rate for hopper trucks, as was used in the emission calculations. This is further required as the issued permit limits the opacity of the uncaptured or fugitive emissions from grain receiving to no more than 5 percent irrespective of whether grain is received by straight trucks or hopper trucks.

The use of an aspirated dump pit with quick-closing doors for receiving of grain by straight trucks provides significantly higher control efficiency than choke flow control on a hopper truck. This compensates for the higher uncontrolled emission factor for any receiving of grain from straight trucks. This occurs because the quick closing doors serve to enclose the unloading operation <u>while grain is actually being unloaded</u>, reducing loss of dust due to wind currents and allowing the aspiration system to operate more effectively. While the doors to the dump pit building must be open for a truck to enter the building, as observed by this comment, the doors do not remain open during unloading of grain. The doors are closed after each truck enters the building, only to reopen after unloading is complete to allow the truck to leave the building and the next truck to enter.

39. The permit should prohibit all outdoor storage of grain for any reason, such as storage of off-specification grain, or outside storage of milled grain from upsets of the mash preparation process.

It is not appropriate for the permit to address the outside storage of grain because the plant is not being developed with facilities to store grain outside or to subsequently handle grain that has been stored outside. It is also not appropriate for the permit to speculate on upsets that might occur at the plant and the actions that might be needed to address them.

Mash Preparation and Fermentation Area (Condition 2.4)

40. My analysis of information in the application for the fermentation scrubber indicates that it will not be able to comply with applicable limits under all likely operating scenarios. Based on the application, the gas flow rate for this scrubber will vary from 6,000 to 13,000 acfm, with inlet VOM concentration ranging from 6,000 to 14,000 ppm and outlet VOM concentration ranging from 35 to 300 ppm. The application also indicates a VOM emission

factor of 900 lbs per million gallons of ethanol, which is equivalent to 11.3 lbs/hour for production of 110 million gallons/year. The permit limits VOM emissions to 11.43 lbs/hour and requires that the scrubber achieve at least 98% control efficiency. These emission limits are essentially based on the promise of maintaining VOM emissions within 900 lbs per million gallons of ethanol.

This data is not internally consistent. Given the data for the upper and lower operating conditions of the scrubber, as well as average gas flow, my analysis indicates that the scrubber will not always be able to comply with the limits in the draft permit.[6] It also indicates that the scrubber will not be able to comply with the hourly emission limit if it can only achieve 98% control efficiency. This raises serious questions about whether the plant will actually be able to comply with annual VOM emission limits.

As also noted in the application, the emission factors for the fermentation scrubber are based on actual test data at similar ethanol plants plus a moderate margin of safety and are considered to be conservative. The analysis performed by this commenter used the extremes of the data for different operating parameters of the scrubber in a way that is not realistic. For example, it is not realistic to combine the stated maximum gas flow and maximum VOM concentration in the exhaust. However, as indirectly shown by the calculations in this analysis, at the typical gas flow rate from fermentation (11,000 acfm), the outlet VOM concentration in the exhaust would have to be about 68 ppm to be in compliance, with a VOM control efficiency of at least 99 %. The scrubber would not be in compliance if the outlet VOM concentration is greater than 127 ppm.

41. The Illinois EPA should question whether the VOM emissions from fermentation can be calculated and effectively limited on the basis of factors expressed in terms of "pounds per million gallons of ethanol." Fermentation is one step removed from the distillation process and efficiencies inherent in its evaluation. It is not practical for an emission test to extend over the time period for production of one million gallons of ethanol, this type of performance factor must be discounted for overall emissions calculations. Traditional stack tests for three one hour periods, accompanied by parametric monitoring to address continuing compliance, are not sufficient to demonstrate that the claimed performance has actually been achieved. The applicant has attempted to lull the Illinois EPA into complacency with the performance data that has been supplied for the fermenters. This is because emission tests are typically conducted over a period of 3 to 4 hours. If an alternative to a control efficiency requirement is needed, a maximum VOM concentration, in ppm, should be set, that would ensure compliance with hourly and annual emission limits.

It is appropriate for the VOM emissions from fermentation to be limited in terms of pounds per million gallons of ethanol produced. This is a simple and direct way to express performance of the fermentation scrubber and limit emissions in relation to the production of ethanol by the plant. While the duration of emission testing will be far shorter than the period of time during

---

[6] For example, if the flow rate is 13,000 cfm and the outlet VOM concentration is 300 ppm, the VOM emission rate would be 58.74 pounds/hour, rather than 11.43 lb/hr as allowed. To be in compliance, the outlet VOM concentration would have to be less than 60 ppm. Likewise, if the inlet VOM concentration is 6000 ppm and the outlet VOM concentration is only 300 ppm, the control efficiency would only be 95 percent, rather than 98 percent as required. To comply with the control efficiency requirement, the outlet concentration would have to be no more than 130 ppm.

which one million gallons of ethanol is produced, the results of emission testing can be readily expressed in terms of pounds of VOM emissions per gallon of ethanol produced. In addition, the permit also directly limits the VOM emissions of the fermentation scrubber, in pounds per hour, and imposes requirements for proper operation of the scrubber.

While a limit set in terms of VOM concentration could be an alternative to the limit expressed in terms of ethanol production, it would be just that, i.e., an alternative. It does not show that the form selected for this limit, i.e., expressed in terms of production, is not appropriate.

42. The application identifies a number of factors that appear to mitigate against long-term assurances of compliance with VOM emission limits by the fermentation scrubber. For example, the application indicates that scrubber water comes directly from a well at temperatures of 47 ºF to 85 ºF. While the permit may require scrubber water temperature not to exceed the temperature during emission testing, it is questionable that this will be achieved in practice without the ability to manage water temperature and equipment or without the ability to independently manage the water temperature. The application also does not show that a programmable logic controller would be used for automated operation of the scrubber to address variation in water temperature, VOM concentration and gas flow rate. At the same time, the water flow to the scrubber is constrained by the water balance for the plant, which is a consideration apart from maintaining the optimum VOM control efficiency. The application also indicates that the exhaust flow from fermentation is widely variable. Applicant has not submitted enough information about the temporal nature of variability of this process to design compliance accountability measures that ensure emission testing will address worst-case emissions. All of these factors should give pause about the emission calculations for fermentation.

The stable source of water for the scrubber provides reassurance that the scrubber will perform with VOM emissions that comply with applicable limits. Unlike plants that use some process water as the water supply for their fermentation scrubber, the water supply for the proposed plant will come directly from the well, minimizing variation in temperature. To assure that emission testing accurately addresses the temperature of the water supply, emission testing will either have to be conducted during hot weather or the water temperature during testing will have to be manipulated to reflect the peak temperature of the supply.

The comment also identifies other techniques that could be used to enhance the performance of the scrubber, if it is necessary to do so. These include addition of a chiller system so that cooler water could be provided to the scrubber. A programmable logic controller could also be used for more careful operation of the scrubber, to enable water flow rate to be managed on a real-time basis based on process parameters, so that compliance is maintained without disrupting the water balance for the plant.

43. The Illinois EPA should question whether the VOM emissions from fermentation can be characterized on the basis of factors expressed in terms of "pounds per million gallons of ethanol." Fermentation is one step removed from the distillation process and efficiencies inherent in its evaluation. It is not practical for an emission test to extend over the time period for production of one million gallons of ethanol, this type of performance factor must be discounted for overall emissions characterization. Traditional stack tests for three one hour

periods, accompanied by parametric monitoring to address continuing compliance, are not sufficient to demonstrate that the claimed performance has actually been achieved. Big River Resources has attempted to lull the Illinois EPA into complacency with the performance data that has been supplied for fermentation.

It is appropriate for the VOM emissions from fermentation to be limited to 900 pounds per million gallons of ethanol produced. This is a fundamental factor for performance of the fermentation scrubber and limits emissions relative to actual production of ethanol. However, as observed by this comment, determining compliance with this factor will not be so straightforward that it can be relied upon by itself. Accordingly, the permit also directly limits the VOM emissions of the fermentation scrubber, in pounds per hour, and imposes requirements for proper operation of the scrubber.

44. The application does not show that the proposed plant will not be a major source for emissions of acetaldehyde. Indeed, the application contains information showing that the proposed plant will be a major source for acetaldehyde, with emissions that exceed the limits in the draft permit. In particular, the application contains results from emission testing of the fermentation scrubber at the White Energy ethanol plant in Russell, Kansas, performed in August, 2002. Based on a NCASI 98.01/USEPA Method 18 analysis, this test measured acetaldehyde emissions of 2.33 lbs/hr from the scrubber while the plant was operating at a rate equivalent to 30 million gallons of ethanol per year. As the proposed plant is over 3.6 times larger, at an equivalent rate of emissions, the fermentation scrubber at the proposed plant would be expected to emit 8.4 lbs/hr or 36.8 tons/yr of acetaldehyde. This would make the proposed plant a major source for hazardous air pollutants, subject to a requirement for a case-by-case determination of Maximum Achievable Control Technology. The application does not include results of other emission tests for acetaldehyde. Big River Resources must submit information to justify its projected acetaldehyde emission rate rather than having the Illinois EPA and the public to accept it on faith. Big River Resources should also justify why its scrubber will achieve better control of acetaldehyde than achieved at the White Energy plant in Russell, Kansas.

The test results from White Energy plant should not be directly applied to the proposed plant, given the difference in timing in the design and development of the two plants and the size of the two plants. The White Energy ethanol plant in Russell, Kansas, is over five years old, so does not reflect advancements in design of fermentation scrubber over the last five years. Equally important, the scrubber was designed to maintain acetaldehyde emissions of that plant below 10 tons per year. The fermentation scrubber at the proposed plant must be designed to achieve significantly greater control for acetaldehyde emissions, given that the proposed plant is almost four times larger than the White Energy plant. Achievement of this additional control is readily accomplished with appropriate engineering design of a scrubber for the necessary level of collection of acetaldehyde by the scrubbant. To achieve the necessary level of control, the fermentation scrubber at the proposed plant is a packed bed scrubber, with upper and lower stages of packing separated by a collector and redistribution plate and followed a mist eliminator.

45. Comments from the State of Nebraska submitted to USEPA in 2006 for its proposed changes to the PSD rules indicate that ethanol plants in Nebraska have had difficulty achieving 98%

control of acetaldehyde emissions. Measured hourly acetaldehyde emissions from some of the fermentation scrubbers cited by Nebraska were significantly higher than 1.43 lbs/hr, the limit that would be set for acetaldehyde for the fermentation scrubber by the draft permit for the proposed plant.

Whether scrubbers at fuel ethanol plants achieve 98% control for emissions of acetaldehyde is different question than whether emissions of acetaldehyde can be effectively controlled so that fuel ethanol plants are not major sources for hazardous air pollutants. In its comments to USEPA, Nebraska did not suggest that acetaldehyde emissions at ethanol plants could not be effectively controlled. Indeed, Nebraska indicated that fuel ethanol plants were controlling acetaldehyde emissions so that they would not be major sources for emissions of hazardous air pollutants. As a result, USEPA's proposed change to the source category for corn fermentation ethanol plants (which would raise the major source threshold under the PSD rules from 100 to 250 tons/year), would have little effect on the level of control that would actually be achieved for VOM. That is, the level of control achieved for VOM is driven by the requirement to effectively control VOM emissions.

The actual emission information accompanying Nebraska's comments to USEPA show acetaldehyde emissions rates of 0.11, 0.55, 0.82, 1.31 and 2.2 lbs/hr from a fermentation scrubber during five separate emission tests conducted between January 2002 and December 2004. This data indicates that the emission limit set for the fermentation scrubber at the proposed plant is achievable.

46. More recent testing of a fermentation scrubber at an ethanol plant with a capacity of 53 million gallon/year owned by US Bio-Energy in Woodbury, Michigan, showed acetaldehyde emissions that were higher than the 1.9 lb/hour limit set for that unit.

The exceedance of an emission limit at another ethanol plant does not show that the emission limits set for the proposed plant will be exceeded. In addition, this comment was not accompanied by information that confirmed the allegation of noncompliance made by the comment.

47. The draft permit would not directly limit the potential emissions of the fermentation area. The permit should physically limit the beer production rate or the fermenter charge rate in order to properly limit the potential emissions the fermentation area. Attempting to limit the potential emissions of VOM from fermentation on the basis of a final production rate, which is several process steps removed and far downstream in the overall process, is not appropriate and does not adequately restrain the potential to emit at the scrubber exhaust emission point. The reason reliance on the final production rate fails to actually limit the potential to emit is because of the variability of the processes downstream from fermentation. For example, the final production rate will also depend on the overall efficiency of distillation.

The operation of the fermentation area is adequately "restricted" by the limit on the ethanol production from the plant. This is because the production of ethanol is an integrated process, with the output of the fermentation area going directly to the distillation area for separation into product ethanol. "Efficiency" of yield is not a factor in this downstream process as it only involves separation or purification of ethanol, first from the beer and then to remove remaining

water. While separate operational limits could certainly be set to restrict the fermentation area, as recommended by this comment, they would not meaningfully enhance the regulation of the plant.

48. Condition 2.4.5(a)(i) in the draft permit provides that the key operating parameters of the fermentation scrubber shall be maintained at levels consistent with levels at which emission testing demonstrated compliance with applicable requirements. The language is not sufficiently explicit to make enforceable a process whereby emissions testing is performed under different process operating variables and an envelope of acceptable operating parameters for the scrubber is determined and then made enforceable. Based on parameter monitoring, there must ultimately be a clear method that provides enforceable criteria as to when a unit must be considered out of compliance.

The effect of Condition 2.4.5(a)(i) is clear. After emissions testing of the fermentation scrubber is performed (which must be conducted while the fermentation area is operating at capacity), the plant must generally continue to operate the scrubber with a minimum water flow rate, maximum water temperature and maximum exhaust gas temperature that are consistent with the values of these operating parameters during emissions testing. Deviations from these operating requirements would be a violation of this condition. This has obvious consequences for the operating conditions for the fermentation scrubber under which the plant elects to conduct emission testing of the scrubber, i.e., testing must be conducted with values of these operating parameters that can be consistently and reliably maintained. While testing of the scrubber with more water would show lower VOM emissions, it would also create a future obligation to always operate with "more water." Of course, emissions testing must also be conducted when the scrubber is operating with enough water that the scrubber meets applicable limits.

Given the straightforward nature of fermentation of corn, the Illinois EPA expects that there will only be a single normal operating mode for the scrubber. While some variation in exhaust gas flow to the scrubber will occur due to the cyclical nature of batch fermentation, this variation will be dampened by the staggered operation of seven fermentation tanks. Accordingly, it seems unlikely that a series of tests of the scrubber under different operating modes will be performed. However, if the plant does elect to conduct multiple tests to address different operating modes or to establish a more complex relationship of operating parameters, this would initially be addressed by the Illinois EPA as part of the review of the plan for testing. It would then be further addressed by the Illinois EPA as part of the processing of the operating permit application for the plant. This would define the different operating modes of the fermentation area for which each set of operating parameter values would apply. The issued permit does address such circumstances, with provisions that would allow operation of the fermentation scrubber pursuant to an alternative "compliance plan" while an application for a revised permit to incorporate such a plan is being reviewed by the Illinois EPA.

49. Condition 2.3.6(a)(i) should also require operational monitoring of the fermentation scrubber for sodium bisulfite injection rate and the concentration of sodium bisulfite in the scrubbant. These will also be important operating parameters for this scrubber, such that minimum sodium bisulfite solution injection rates and aqueous sodium bisulfite concentrations in the scrubbant must be considered floor values, which are set during emissions testing, to indicate

proper scrubber operation. In addition, monitoring and periodic testing should be required related to addition of sodium bisulfite to the scrubbant and the concentration of sodium bisulfite in the scrubbant.

If the addition of sodium bisulfite or other additive to the scrubbant for the fermentation scrubber is determined to be important for effective control of emissions, provisions can <u>and will</u> be set in the operating permits for the plant to address such additions. Consistent with the approach in the construction permit, the operating permits for the plant would treat such additions as "key operating parameters" for the scrubber. As recommended by this comment, required levels of addition would be set based on levels during testing with appropriate monitoring and recordkeeping to verify compliance. However, information has not yet been presented to enable such provisions to be appropriately set at this time. In particular, it would be preferable if proper operation of the scrubber does not necessitate use of an additive as operation of the scrubber would be simpler. If an additive is needed, there may be several additives that could be used, with difference implications for the operation of the plant. In addition, use of an additive may necessitate other changes to the provisions of the permit addressing proper operation of the scrubber.

50. The conditions of the permit that set required values of operating parameters for the fermentation scrubber, as well as for other control devices, must be written to ensure that the plant may not "cherry pick" operating parameters to comply with only a single emission limit at a time. The process of establishing an operating condition envelope for compliant operation must reflect simultaneous compliance with all limits demonstrated with simultaneous and corresponding ranges of operating conditions during the test.

The draft permit does not allow "cherry picking" of operating requirements, as this comment cautions against. Where the permit contains multiple operating requirements for a control device, all requirements are to be met. Expressed in other words, a deviation from a single requirement for a control device is a deviation from proper operation of the device, even if the device is "overcomplying" with other requirements.

51. For the fermentation scrubber, the permit must establish calibration and QA/QC requirements for required parametric monitoring devices, which are stated as either USEPA methods or recognized technical society (i.e. ASTM) published methodologies for ensuring collection of valid monitoring data. In addition, the draft permit should require collection of at least 95% valid data from such process and scrubber parameter monitoring devices.

The permit appropriately addresses the operation of parametric monitoring systems by requiring that the plant operate these devices in accordance with good monitoring practice, including operation in accordance with manufacturer's recommendations or other procedures as necessary to assure reliable operation of the devices. It is not necessary for the permit to establish specific protocols for measurement of parameters like pressure drop, temperature or liquid flow rate, for which operational measurements are routinely and reliably made by sources as part of their standard operating practices.

52. The draft permit should require that emission testing for the fermentation scrubber be conducted when process units are operating at least at 95% of their maximum rate.

The permit generally requires that emission testing be conducted during operating conditions that are representative of maximum emissions. (See Condition 3.1-1(a).) An obvious element of the operating conditions that produce maximum emissions from emissions units controlled by a scrubber is operation in the maximum operating range of those units, so as to present the scrubber with a high pollutant loading and high flow rate.

53. The "uncontrolled" VOM generated by the fermentation process depends on the fermentation cycle in each tank, breathing losses, displacement losses upon filling and other factors. Actual VOM emissions depend on surrogate parameters of both the process generation of VOM and the parameters of scrubber operation. As a result, the recordkeeping operations required under Condition 2.4.9(a) are insufficient to reflect process and scrubber control parameters from which emissions can be determined and compliance with emission limits assured.

The records required by Condition 2.4.9(a) are not intended to be used to directly determine VOM emissions from the fermentation area or compliance with VOM limits. Rather they are intended to provide basic information about the operation of the fermentation tanks so that the Illinois EPA can readily identify any significant changes in the fermentation process. If such changes did occur, the Illinois EPA would then be able to assess whether the changes would significantly affect the VOM emissions generated from fermentation, so that retesting of the fermentation scrubber should be required.

54. The draft permit does not indicate exactly how fermentation emissions would be calculated from monitored data and required records. Since the seven fermentation tanks operate as batch processes, rather than merely addressing tank liquid levels, recordkeeping must address aspects of the fermentation cycle on each tank, such as the time of filling, tank temperatures, hourly average fermentation rate, hourly average transfer rate to the beer well and likely other factors. The rate of emissions would be functions of both these factors and the control device operating parameters. Until there is a firm method for making ordinary emission determinations from this unit from process and control device parameters listed in the permit, a permit should not be issued. If emissions will instead be related solely to a function of operating parameters for the scrubber and process throughput in the fermentation area, then this decision should be documented and sufficient monitoring and recordkeeping should be imposed to both support emission determinations and assure compliance with applicable limits.

As explained above, the permit does not intend that emissions generated by the fermentation area be calculated from detailed operating data for the fermentation area. Rather, emissions from the fermentation area would be calculated from general emission factors for the area, which would be based on the results of emissions testing. Compliance would be determined by proper operation of the fermentation scrubber, in a manner that is consistent with the operation of the scrubber during the most recent emissions testing that demonstrated compliance with applicable limits and requirements.

55. Because of process and control device variability and because of the small margin of compliance with the major source threshold, the permit should require a continuous VOM emissions monitor on the fermentation scrubber, which is clearly available technology. In

addition, a continuous monitor for scrubber gas flow should be required for fully integrated VOM concentration and flow characterization.

In particular, the application indicates that scrubber water comes "directly from well" at temperatures of 47 ºF to 85 ºF. There is no basis for believing that the plant will be able to maintain this range in practice without the ability to regulate scrubber water temperature, especially during very hot weather. There is indication of physical equipment or ability to independently regulate the scrubber water temperature. If the plant uses stored well water, scrubber water temperature might not reflect cool well water temperatures. The application also does not indicate a programmable logic control system would be used for automatic controls on scrubber operation to address temperature, gas concentration and flow process swings. In addition, the application the supply of scrubber water is constrained by the water balance for the plant, which is a consideration apart from scrubber operation for VOM control. Finally, the application indicates that generation of emissions from the fermentation area is widely variable. However, the application does not include enough information about the time-related nature and characteristics of this variation to ensure that ensure emission testing will occur during periods of maximum emissions. Accordingly, continuous emissions monitoring should be required for VOM.

The circumstances of the fermentation process do not justify continuous emissions monitoring for VOM. While there may be some variability in operation, this variability should not be so great as to necessitate continuous monitoring. It is widely recognized that the operational conditions under which emission testing of fermentation scrubbers is performed must be carefully selected so that they represent worst-case performance and maximum emissions. However, the consequence of this recognition is that these conditions are not developed from design data submitted in a construction permit application. Instead, they are developed based on actual operating data during initial operation of equipment, subject to review and approval by the Illinois EPA. If necessary, several emission tests can also be performed to assure that sufficient emission data is collected to address variation in performance. Finally, emissions monitoring for VOM clearly poses technical challenges. If undue variation in operation were to be revealed, attention would be better focused on eliminating that variation and enhancing the scrubber to better control emissions, rather than creating new monitoring protocols that would do nothing to directly reduce emissions.

56. Condition 2.4.10(a)(i) of the draft permit, which addresses immediate reporting by the plant for certain deviations from operating requirement for the fermentation scrubber, is not specific enough for proper enforcement. This is because it is not clear what a 2.0% exceedance would be. A 2% temperature exceedance in ºF would be different than a 2% exceedance in ºC. Does a 2% exceedance mean 2% above the floor or a maximum value of an operating parameter? The permit should address parameter envelopes of expected operations proposed for establishment on process and control device parameters during emissions testing, with subsequent approval by Illinois EPA.

The issued permit expresses temperature values in ºF to provide clarity on how a 2% exceedance of an operating parameter value for temperature is to be determined. For parameters for which minimum values are set, immediate reporting would be required if the actual value of a parameter were 2% less than the set value; for maximum values, immediate

reporting would be required if the actual values were 2% higher than the set value. In addition, the plant would have to report all exceedances in its quarterly reports.

The permit clearly defines the general mechanism by which the required or set values for operating parameters would be set, i.e., the value of the specified operating parameters during testing. Any further action or "interpretation" that becomes necessary with respect to the set values of operating parameters for the fermentation scrubber can occur in the processing of the operating permit for the plant by the Illinois EPA.

Miscellaneous Emission Units for Mash Preparation and Fermentation (Condition 2.4)

58. The draft permit does not identify the Centrate Tank and the CIP Mash Screen as being controlled emission units. Calculating the VOM emissions from the Centrate Tank by the methods used in the emission calculations in the application (based on a 40 million gallons per year plant, not 110 million gallons per year) yields VOM emissions of 10.7 tons per year, which would put the plant well over the 100 ton major source threshold.

Both the Centrate Tank and the CIP Mash Screen will be controlled by the oxidizer/boiler systems. This is clarified in the issued permit. The emissions of these units are included with the permitted emissions of the oxidizer/boilers systems.

Distillation Area (Condition 2.5)

59. For units that are controlled by the oxidizer systems, Condition 2.5.5 should clarify that during the shutdown of units, the heat input level of an oxidizer shall be maintained above the specific level that has been previously demonstrated in emissions testing to show compliance with applicable limits.

The issued permit clarifies operating requirements for the oxidizer systems during shutdown of emission units. (See Condition 2.5.5-1(c).) However, it is not appropriate to require that a specific firing rate be maintained during such periods. The permit instead restates the general obligation that equipment be operated in accordance with good air pollution control practice. This requires that the temperature in the combustion chamber of the oxidizers be maintained at the "compliant" level for as long as it is feasible to do so, ideally until after process units are shutdown. If operation of process units lags behind the oxidizers, they must be expeditiously shutdown once the temperature in the oxidizers drops below the compliant level.

60. The application does not include information on the potential for VOM emissions through pressure relief valves and rupture disks in the distillation area. If the distillation area will have pressure relief valves, rupture disks, or other kinds of bypass release devices, these devices should be listed and their emissions should be subject to recordkeeping requirements. If these devices are part of the design, reference to any emissions from such devices should be included in the recordkeeping requirements of Condition 2.5.9. In addition, these devices should be subject to the requirements of a Leak Detection and Repair Program.

Any pressure relief devices that are needed in the distillation area, with discharge to the atmosphere rather than to a control device, would be addressed by Condition 2.8 of the issued permit. This condition addresses components of the piping system and access hatches in process vessels at the plant that are in VOM service but are normally closed to the atmosphere. As such, Condition 2.10 is also the appropriate condition in which to address pressure relief devices. Condition 2.10 does require that the plant implement a Leak Detection and Repair Program, which program would have to extend to any pressure relief devices in VOM service in the distillation area.

Feed Dryers and Oxidizer/Boiler Systems (Condition 2.5)

61. A recent test of the thermal oxidizer at the VeraSun plant in Fort Dodge, Iowa showed a NOx emission factor of nearly 0.07 lbs/mmBtu, which is higher than the 0.05 lb/mmBtu factor cited in the application as a manufacturer's guarantee for the oxidizer systems at the proposed plant.

This comment was not accompanied by detailed data for the recent emissions testing at VeraSun cited in the comment, so the Illinois EPA was unable to review the commenter's analysis of the results of this test. However, this testing is believed to support the NOx emission rate used in the emissions calculations for the proposed plant. In particular, it is believed that a NOx emission factor lower than 0.05 lb/mmBtu is shown when the measured NOx emission rate, in lbs/hour, from the stack of the oxidizer is divided by the total heat input into the dryer-oxidizer system, including the fuel heat input into both the feed dryers and oxidizer. In this regard, the emission calculations in the application are based on a NOx emissions factor of 0.05 lb/mmBtu for the fuel input to both the dryers and the oxidizer.

Moreover, assuming that the commenter did properly analyze the results of this test at VeraSun, Fort Dodge, the calculated NOx emissions factor does not show that the NOx emission factor used in the application for the proposed plant is not achievable. The results of emission testing are also available for testing conducted in 2004 at the VeraSun plant in Aurora, South Dakota, which had a nominal capacity of 100 million gallons/year in 2004, similar to the proposed plant. This testing for VeraSun's Aurora plant showed lower NOx emissions than the testing at the Fort Dodge plant. The Aurora testing showed total NOx emissions of 0.039 lbs/million Btu and 16.37 lbs/hours, for the two oxidizer systems at the plant. This shows that a NOx emission factor of 0.05 lbs/million Btu can be met at the proposed plant.

62. In an e-mail to Gregory Fried, USEPA, dated October 10, 2003, William Roddy, ICM, discusses the effect of the nitrogen content of the PM in the exhaust from a feed dryer on the NOx emissions from the oxidizer. The e-mail cites data for two different feed dryers, one of which was an ICM model, showing that the PM entering the oxidizers contained 2 lbs of nitrogen per hour. The e-mail further indicates that complete conversion of that nitrogen to NOx would yield a NOx emission factor, just from combustion of PM in the oxidizer, of about 0.06 lbs NOx/mmBtu, for a heat input to the oxidizer of about 100 mmBtu/hr. The NOx emission factor for the feed dryers and oxidizer used in the application for the proposed plant, 0.05 lb/mmBtu, does not account for this fuel-bound PM -related NOx, so that NOx emissions are understated. If 0.06 lbs/mmBtu of NOx is generated from fuel-bound nitrogen

contained in PM (separate from thermal NOx), an additional 47.3 tons of NOx would potentially be emitted each year, that has not been accounted for in the application. These additional NOx emissions, when added to the potential NOx emissions of the dryer-oxidizer systems that have been accounted for, 92.86 tons/year, would put the plant well over the 100 ton per year major source threshold.

The e-mail from 2003 cited in this comment does not "invalidate" the NOx emission factor or emission calculations for the dryer-oxidizer systems in the application. This e-mail is almost four years old and was prepared in the context of proposed changes to the federal New Source Performance Standards (NSPS) for Steam Generating Units. An overall NOx emission factor of 0.05 lb/mmBtu is reasonable for the dryer/oxidizer systems at the proposed plant, as applied to the heat input to both the dryers and oxidizer. This appears to be confirmed by the emissions testing at VeraSun, also cited by the commenter, which is believed to address NOx emissions from a dryer-oxidizer system, including both fuel-bound NOx associated with PM and thermal NOx from combustion of natural gas. In any event, this comment is flawed as it presumes that fuel-bound, PM-related NOx has not been accounted for in the emission calculations in the applications, whereas NOx emission factors must account for overall NOx emissions. It also revisits a speculative and outdated analysis, which was based upon specific levels of PM and nitrogen in the dryer exhaust and complete conversion of that fuel-bound nitrogen to NOx. If instead only 20 to 40 percent of the fuel bound nitrogen is converted to NOx, as is more commonly expected for NO emissions when low-NOx comubustion techniques are is used, the fuel-bound nitrogen is only one component in the overall emissions of NOx the dryer-oxidizer systems as would be addressed in an overall emission factor.

63. The emission factor used in the application to calculate CO emissions from the feed dryers is not supported by the results of a stack test conducted in 2004 at VeraSun, Aurora, which were submitted in the application. This test showed a three-test average of 18.3 lbs CO per hour. A hand-written notation of the copy of the test results, presumably made by the South Dakota Department of Environment and Natural Resources, indicates test runs were at 38.2 ton /hr feed output, or about 70 percent of design dryer capacity, 54 ton/hr.[7] The resulting CO emission factor, 0.479 lbs per ton, is almost 13% higher than the 0.425 lb/ton factor used in the application for the proposed plant. At 356880 tons/year of feed, use of the VeraSun-Aurora factor would put the potential CO emission of dryer-oxidizers at the proposed plant at 85.47 tons/year. However, the annual potential to emit must be based on the maximum design process rate of 42 tons feed/hr for potential CO emissions of 88.1 tons per year and 20.1 lbs per hour.

The emission factor actually used in the calculations for CO emissions for the feed dryers at the proposed plant for the purpose of establishing the limits in the permit was 0.5 lbs/ton of feed. This factor is consistent with the results of emission testing at VeraSun, Aurora. The emissions of the feed dryer/oxidizer/boiler systems at the plant are limited to 90.11 tons/yr and 22.8 lbs/hr, which are higher than the limits calculated in this comment.

---

[7] This is also consistent with the reported fuel heat input data during the test, i.e., a test average of 142 mmBtu/hour total for four dryers compared to a design total dryer capacity of 170 mmBtu/hr and a total oxidizer heat input of 210 mmBtu/hr, compared to a total oxidizer design capacity of 330 mmBtu/hr.

Moreover, the CO emissions of the oxidizers systems at the proposed plant, like any thermal afterburner, can be readily adjusted to achieve a higher control efficiency for CO emissions. This is accomplished by operating with a higher temperature in the combustion chamber.

64. Setting stack gas concentration limits for CO and VOM without specifying a correction to dry standard conditions and to a specific oxygen concentration renders the limits unenforceable in practice since a source may dilute the exhaust with air.

Emission limits expressed in terms of actual stack gas concentration, without "correction factors," as established in this comment, are fully enforceable. While correction factors are commonly used when setting concentration-type limits for boilers and incinerators, this is not the case for process units like the feed dryers and other VOM process units that are being controlled by the oxidizers. For Condition 2.5.6(a), which addresses the oxidizer/boiler systems as they function as control devices for VOM and CO emissions, it is not necessary that correction factors accompany the concentrations limits for VOM and CO emissions. Moreover, "correcting" limits to dry standard conditions is not necessary to prevent dilution of the exhaust as such a practice would be inconsistent with both practical operation of the emission units and good air pollution control practice.

65. The application indicates that the SO_2 emission calculations for the proposed plant are based on emissions testing at Glacial Lakes, but test results were not included in the application. The draft permit does not include any compliance monitoring for SO_2 emission. At a minimum, the oxidizer/boiler systems should be subject to initial emissions testing for SO_2 and emissions or operational monitoring to ensure compliance.

The results of the SO_2 emission testing at Glacial Lakes, which show SO_2 emission of 0.17 lbs/ton of dry feed, have been submitted to the Illinois EPA. The emission calculations for the proposed plant were conservatively performed using an SO2 emission factor of 0.45 lbs/ton. The issued permit requires emissions testing for SO_2 emissions from the oxidizer/boiler systems. Recordkeeping is required for use of sulfuric acid in the fermentation process, which was identified in the application as the source or origin for SO_2 emissions during feed drying.

66. The calculations for potential CO emissions used an annual production rate of 356,880 tons of dry feed. However, the maximum dryer process rate is 42 tons per hour. As proposed, the draft permit contains no enforceable hourly or annual limits on feed production.

The dry feed production of the proposed plant would have been limited by the draft permit and is limited by the issued permit. Refer to Conditions 1(c).

67. The design drawing for the oxidizers submitted in the application shows a small transfer line from the natural gas main to the larger waste gas line before entry to the oxidizer. The emission calculations presented in the application do not address the emission consequences or purpose of this line, which is labeled "assist gas." This is clearly a route for introducing natural gas to the oxidizer that is separate and distinct from the natural gas line to the burner. A permit should not be issued unless the purpose and emission consequences of the "assist gas" line are fully explained to ensure that "assist gas" added to the waste gas feed to the

oxidizers are properly subjected to monitoring and review as to impact on emissions and throughput of the oxidizers.

As suggested by its name, the "assist gas" line allows natural gas to be added to the waste gas sent to the oxidizers, which comes from certain mash preparation units and the distillation units, to enhance the heat content of this gas. The role of the assist gas would be to facilitate combustion of the waste gas in the oxidizer and the assist gas would be burned with the waste gas. Thus it is not necessary to consider assist gas as part of the burner capacity of the oxidizers.

68. To be consistent with a relevant USEPA determination on the relationship between feed dryers and oxidizers with heat recovery steam generators (HRSG), the permit should prohibit operation of the dryers solely to provide heat to the HRSG, other than for pre-heating the dryers. In particular, USEPA has made a determination for systems like those at the proposed plant stating that the feed dryers should not be considered part of the steam generating unit for purposes of the NSPS. In its determination, USEPA explained:

> The purpose of the DDGS dryers is to produce marketable dried grains. Although the DDGS exhaust provides some heat input to the TO, the TO is the source providing exhaust gas directly to the HRSG. Furthermore, the combined cycle system of the TO-HRSG can operate to produce the required steam for the plant output without the heat input from the DDGS dryers. Therefore, the EPA finds that the DDGS dryers are separate sources and are not part of the TO-HRSG combined cycle system. (Letter from Michael Alushin, USEPA, to William Roddy, ICM, July 29, 2004, NSPS Applicability Determination, USEPA Control Number 0500059)

To be consistent with USEPA's determination, the permit should prohibit operation of the burners in the feed dryers solely to provide heat to the HRSG, without drying of wet material, other than for warm up of the dryers. If the dryers were operated solely to provide heat to the heat recovery steam generators, the dryers would be operating for the primary purpose of providing heat for steam generation.

The permit does not need to prohibit operation of the dryers as requested by this comment. This is because it is not reasonable for the burners in the dryers to be operated for purposes that are unrelated to drying of feed. The burners in the oxidizers have ample capacity, sufficient to provide the heat input to the HRSGs to produce the steam for the plant when feed is not being dried. The oxidizers are also located immediately before the HRSGs, so as to efficiently provide this heat, without the operational complications that would accompany running feed dryers when they are empty. Moreover, it is exactly because of this "boiler-like" capability and the placement of the burners in the oxidizers that the oxidizers and associated HRSGs qualify as steam generating units for purposes of the NSPS.

69. The short-term NOx emission limit for the oxidizers in the draft permit cannot be enforced through emission testing. This is because "Compliance with this limit shall be determined on a 30-day rolling average, using the methodology of the NSPS." Accordingly, emission testing cannot be used to enforce the short-term NOX emission limit. Moreover, this is also improper because the NSPS does not provide for short-term emission limit so no methodology exists to

determine compliance. The permit should set a NOx limit of 0.05 lb/mmBtu emission limit, with compliance to be determined by continuous NOX emission monitoring. The mass NOx limit, 11.8 lbs/hr, should also be determined in a similar manner, rather than on a 30-day rolling average.

The form of the short-term NOx limit for the oxidizers in the draft permit, as proposed, does not make the limit unenforceable. The limit is also set in an appropriate form as it is in the form of the NSPS emission standard, to which the oxidizers/boiler systems are subject. The NSPS contains compliance determination procedures in 40 CFR 60.46b that address a NOx limit set in this form, i.e., a 30-day rolling average. While these procedures do not involve traditional emission testing, they will still be fully adequate to enforce the limits on NOx emissions from the oxidizers, as they serve to generally enforce the applicable NSPS standard for NOx. These procedures specify that compliance with the NSPS NOx limit is to be determined using compliance tests that cover 30 operating days, with actual emission data for each day determined by continuous monitoring. Thereafter, a new 30-day rolling average emission rate is calculated each operating day from the monitored data for the 30 preceding operating days.

70. Because of the exhaust gas from the feed dryers and other emission units that enters the oxidizers, it will not be possible to use natural gas firing rates to determine stack gas flow rates with an "F-factor." The permit should disallow use of natural gas F-factors for this purpose since their use would introduce errors into the computation of mass emission rates. Instead, the permit should require a monitoring of exhaust gas flow monitor from the oxidizers to properly combine pollutant concentration data from the continuous emission monitor with to develop mass rate and mass per heat input compliance data.

As noted by this comment, for the dryer/oxidizer systems, it will likely not be possible to use F Factors in the procedures to convert monitored data for NOx into the terms needed to determine compliance with the standards and emission limits for NOx. However, the procedures that are to be used in place of an F factor should not and need not be established by the permit. This is because the oxidizer/boiler systems that would now be used at the plant are subject to the NSPS. Accordingly, the necessary source-specific procedure would be approved by USEPA, rather than the Illinois EPA, as the USEPA reviews and approves source-specific monitoring and compliance procedures for units subject to NSPS. Accordingly, it would be premature for this permit to require monitoring of gas flow along with emissions monitors.

71. For the oxidizer/boiler systems, the permit should require continuous monitoring for flue gas oxygen concentration and flow rate, as well as combustion temperature. Monitoring of these two additional parameters is required to verify proper combustion conditions and confirm compliance with hourly emission limits. The monitoring required for these parameters should include numerical tolerances on the accuracy of the measuring devices, requirements for testing to verify accuracy and the specification of required standards (such as from ASTM) for quality assurance/quality control testing. These provisions should not simply rely on a "manufacturer's recommendations." Reliance on "manufacturer's recommendations" is too vague to be enforceable in practice.

For afterburners, including oxidizer/boiler systems like those at the proposed plant, operational

monitoring of combustion chamber temperature is generally sufficient to confirm proper operation for effective combustion. Additional operational monitoring, as suggested by this comment, is only considered if specific circumstances are present, e.g., low oxygen content in the exhaust stream from the process stream or an afterburner whose capacity is not sufficient if all process units served by the device are being operated. These circumstances are not present for the oxidizers at the proposed plant.

72. The draft permit sets an annual limit on the amount of natural gas used at the plant. However, there is no corresponding short-term limit on the amount of natural gas used by the oxidizers and dryers to limit their potential to emit or meet short term NOx emission limits. A physical limits related to potential emissions should be included in the permit and adapted to corresponding emission limits on both an hourly and annual basis for the most restrictive pollutant.

The draft permit addresses firing of natural gas in the feed dryers and the oxidizers on a short-term basis by conditions that limit the rated heat input capacity of these units on an hourly basis. The NOx emission limits that have been for these units are based on operation at the rated firing rates of the units.

73. The permit should set a physical limit on the input to the dryers or the production of dry feed. The emissions of PM, CO and VOM from the dryer/oxidizer systems are determined by the process rate of the dryers, as well as the control efficiency of the oxidizers. A limit on the amount of wet material charged to the dryers or alternatively, on dry feed, should be set in order to provide a physical limit on the potential to emit for the dryers.

The permit limits the amount of feed that is produced by the plant on an annual basis. This limit on production is adequate to limit the amount of material handled by the feed dryers and constrain their potential emissions. It is not necessary to set further restrictions on operation of the dryers. Testing is to be conducted under "worst-case" operation conditions, i.e., operating conditions that generate maximum levels of uncontrolled emissions. As emission testing confirms compliance of the feed dryers under such conditions, compliance is also confirmed under less demanding operating conditions.

74. Records for natural gas usage in the feed dryers and the oxidizers must be kept on an hourly basis, for every operating hour, to assure compliance and to have emission limits for CO and NOx be practically enforceable if continuous monitoring is not performed. Condition 2.6.8-3(a) requires that natural gas usage be recorded only on a month basis. However, monthly recordkeeping does not assure compliance with the hourly emission limits for the RTOs.

The permit imposes recordkeeping requirements that are adequate to verify whether the oxidizer/boiler systems comply with hourly emission limits. Hour-by-hour recordkeeping for natural gas usage of the feed dryers and oxidizers is not necessary or appropriate to address compliance with the applicable CO and NOx emission limits. The permit requires detailed records for those particular periods, or hours, when an emission unit is not operating normally, which records must specifically address the possibility and nature of any excess emissions. At other times, when a unit is operating normally, records are only required to confirm normal operation. This approach does not necessitate maintaining records of emissions hour-by-hour.

Likewise, this approach does not require records of the usage of natural gas on an hour-by-hour basis. Instead, records of the natural gas usage of emission units may be maintained on a longer-time period, as needed to calculate the "base" emissions of the unit attributable to normal, compliant operation.

75. The permit should require all emission testing to be done at maximum process rates. In addition, further test conditions during a series of emissions tests should also show compliance with VOM and CO control requirements, stack gas concentration and percentage reduction requirements at the lowest oxidizer heat input rate for the unit that is expected in regular operations.

Emissions testing must be performed at levels that reasonably represent the maximum levels of emissions, which generally requires operation at the maximum operating rate or production rate of process equipment.

76. Continuous emissions monitoring, using Quality Assurance and Quality Control protocols similar to those in the NSPS, should be required for NOx and CO emissions from the thermal oxidizers. Given the small margins from the major source thresholds, continuous monitoring is the only means by which the plant can ensure that emissions do not cross such thresholds.

Continuous monitoring for NOx emissions will be required for the oxidizers pursuant to the NSPS. As a result, these systems are subject to the NSPS for boilers, 40 CFR 60, Subpart Db, including requirements of the NSPS for continuous monitoring for NOx.

Continuous monitoring for CO emissions of the oxidizers was appropriately addressed by the draft permit. The draft permit provided that continuous monitoring would have to be begun for CO if, based on the results of emission testing, CO emissions of the oxidizers did not normally comply with the applicable limit by at least 20 percent This approach to CO monitoring is appropriate as the determination whether such monitoring is needed for the oxidizers is made based on their actual performance, rather than on the conservative design data in the application.

77. Condition 2.5.5(c)(iv) raises the possibility of different operating modes of the process units at the plant. The provision should be clearly require that any proposed alternate operating mode of process equipment, including 100% or less wet cake dispatch from the plant, be evaluated in emission testing.

This condition addresses operation of the oxidizer/boiler systems in conjunction with emissions testing. The purpose of this condition is to allow the plant to operate these systems at different combustion chamber temperature(s) so the plant can to conduct testing at different temperature(s) if it desires, to evaluate the effect on emissions. In the absence of this condition, once initial emission testing of the systems was conducted, the systems would always have to be operated to be consistent with the initial emission tests, which could never be revised. This is because the permit would not authorize operation at a different temperature, even for the purpose of emissions testing.

78. The permit should not allow termination of continuous emissions monitoring for NOx in favor of parametric monitoring. Because of the relationships between feed dryer operation and oxidizer equipment and linkage to other parts of the ethanol production process, it is not practical or desirable to attempt parametric monitoring for emissions of NOx,....particularly when the plant has small margin from the NOx major source threshold.

The provisions of the permit related to parametric monitoring for NOx emissions reflect the applicable provisions of the NSPS. With the approval of the permitting authority, the NSPS allows parametric monitoring to be conducted as an alternative to continuous emissions monitoring. The prerequisite for such approval is the collection of sufficient NOx emission data with continuous emissions monitoring to demonstrate that NOx emissions of the unit in question may be reliably correlated with and determined from the values of various operating parameters of the unit. Accordingly, the plant is entitled to pursue approval for parametric monitoring if it desires, as is accommodated by the terms of the permit. However, approval for such parametric monitoring will not be forthcoming if it is not adequately supported or justified.

As the commenter believes, given the nature of the units in question, that it will not be possible to develop a parametric monitoring plan, the commenter's concerns are directly addressed. That is, development of an approvable parametric monitoring plan will not be possible. Therefore, continuous emissions monitoring will continue to be required for the dryer-oxidizer-boiler systems at the plant.

79. The permit should not allow continuous emissions monitoring of CO emissions from the oxidizers to be discontinued. If a control device is needed to assure compliance with emission limits, continuous emission monitoring should be required to assure continuous compliance.

As the federal NSPS, which in the issued permit establishes the requirements for monitoring NOx emissions from the oxidizer/boiler systems, allows NOx monitoring to be conducted either with traditional continuous emissions monitoring or with approval by the Illinois with parametric monitoring, a similar approach is also generally appropriate for emissions of CO. If emissions of CO from the oxidizer/boiler systems can be reasonably addressed without continuous emissions monitoring, continuous monitoring should not be required. This is particularly true as this may necessitate routine operation of a unit with a greater margin of compliance from applicable limits and standards than would be provided with continuous emissions monitoring, which could enable operation and emissions that are very close to applicable requirements.

The presence of a control device on a unit is only one factor that should be considered when deciding whether continuous emissions monitoring is appropriate. Other relevant factors include the type of unit, the type of control device, the applicable limit or standard, the expected actual emission rate, the size of the unit, and compliance procedures other than emissions monitoring that can be implemented for the unit.

80. The permit should not allow continuous emissions monitoring for CO to be discontinued because monitoring of CO emissions also serves as a surrogate for monitoring of VOM emissions, in a manner that is more direct than mere monitoring of combustion temperature

and flue gas oxygen, which should still be required by the permit.

The circumstances for CO emissions are not altered by the fact that CO can serve as a surrogate for VOM. If the oxidizer/boiler systems can be operated so that compliance with CO limits can be readily verified without the need for CO monitoring, this also means that the systems can be operated so that compliance with VOM limits is also assured.

81. For the oxidizers, the permit should require continuous monitoring for flue gas oxygen concentration and flow rate, as well as combustion temperature. Monitoring of these two additional parameters is needed to verify the presence of operating conditions for proper combustion and confirm compliance with hourly emission limits. Combustion monitoring traditionally embraces both temperature and oxygen monitoring to ensure good combustion conditions are maintained. . These monitoring requirements should include performance specifications for the monitoring devices and requirements for practices for quality assurance/quality control.

For afterburners, including oxidizer/boiler systems like those at the proposed plant, operational monitoring of combustion chamber temperature is generally sufficient to confirm proper operation for effective combustion. Additional operational monitoring, as suggested by this comment, is not typically required. It is only considered if specific circumstances are present, e.g., low oxygen content in the exhaust stream from the process stream or an afterburner whose capacity is not sufficient if all process units served by the device are being operated. These circumstances are not present for the oxidizers at the proposed plant.

82. The monitoring required for these parameters should include numerical tolerances on the accuracy of the measuring devices, requirements for testing to verify accuracy and the specification of required standards (such as USEPA Performance Specifications or ASTM standards) for quality assurance/quality control testing. These provisions should not simply rely on “manufacturer’s recommendations.” Reliance on “manufacturer’s recommendations” is too vague to be enforceable in practice.

As previously explained, for certain operational monitoring and instrumentation, a requirement that a source follow manufacturer’s recommendations is enforceable. If circumstances warrant, it is a simple matter to compare the actual practice or actions by a source to those that are recommended by the manufacturer. It is not necessary for the permit to establish specific protocols for measurement of parameters, for which operational measurements are routinely and reliably made by sources as part of their standard operating practices.

83. The operating ranges for combustion temperature and oxygen in the oxidizers must reflect evaluation of continuous monitoring for both NOx and CO, since simultaneous compliance with both requirements will increase one pollutant while decreasing another.

While the oxidizers must simultaneously comply with applicable emission limits for NOx and CO, this does not pose special concerns. Unless otherwise provided by a specific standard or limit, all emission units must simultaneously comply with all applicable requirements and limits. This is routinely considered when emissions calculations are performed for a unit that

emits both NOx and CO, as a set of emission factors is used that can both be met simultaneously. If the factor for either pollutant is adjusted, the effect of the adjustment is considered with revised emission calculations for the other pollutant. As a result, the limits that are eventually set for a unit should be such that both limits can be met and they are not mutually exclusive. In addition, emissions testing, or emissions testing and monitoring, are conducted in a manner that confirms that both limits are met.

84. Condition 2.5.10 on reporting does not appear to require a complete protocol/suite of traditional continuous monitoring quarterly reports. The reporting provisions should be considerably more robust, indicating that continuous monitoring reports for NOX and CO be submitted quarterly and that such reports contain information for any emission violations and their causes, information for monitor downtime and its causes, summaries for both emission violations and monitor downtime as a percentage of unit operating time, and other traditional measures. Similarly, for required parametric monitoring, reports, the permits should clearly require reports that included summaries of applicable data and information on accuracy testing, parameter exception periods, monitor downtime.

Continuous emissions monitoring must be conducted in accordance with relevant monitoring requirements of the federal NSPS, included detailed reporting of information as addressed by this comment.

85. Reports on accuracy testing of parametric monitoring devices, parameter exception periods, parameter monitoring downtime and summaries of applicable data should be clearly set forth in the permit language as clearly stated applicable requirements.

The permit sets appropriate requirements for operation of parametric monitoring devices and related recordkeeping and reporting. These provisions are not as prescriptive as those for continuous emissions monitoring, given the simpler and more straightforward nature of the parametric monitoring required by the permit.

86. Condition 2.5.11(b) of the draft permit would interfere with USEPA's credible evidence rule by creating a presumption that compliance with emission limits for pollutants other than NOx can only be determined based on equipment operation, as addressed by required records, and appropriate emission factors based on emission testing. All credible evidence should always be considered in compliance determination. As written, Condition 2.5.11(b) could even be construed to interfere with emission testing or use of operating parameters that are not addressed in required recordkeeping as a means to determine compliance.

Condition 2.5.11(b) of the draft permit does not restrict use of credible evidence to determine whether the oxidizer/boiler systems are in compliance. It merely restates the commonsense principle that the emissions of these systems must be determined from how these systems are operated (which is addressed by records required by the permit) and appropriate emission factors (which would most likely be based upon emission testing for the systems). During the period of emissions testing, the appropriate emission factor for a system is unquestionably the emission factor actually measured during testing. During other periods, the appropriate emission factor might or might not be the specific emission factor measured during testing, depending on how a system was being operated. During period when a system was operating

improperly, engineering judgment would necessarily have to be used to establish an appropriate emission factor to specifically address such period, which factor could be significantly different than the factor actually measured during emissions testing.

Feed Cooler (Condition 2.5)

87. Because of the elevated temperature of the feed entering the feed cooler, there is significant potential for continuing thermal decomposition of the feed and thus generation of condensible particulate from the feed cooler. Because the application did not include any allowance for this phenomenon, the potential PM emissions from the feed cooler calculated in the application are understated. For the baghouse controlling the feed cooler, the application uses a factor of 0.005 grain per standard cubic foot (gr/scf). This is a common vendor guarantee for baghouses for filterable-only particulate. If the PM/PM10 potential to emit is calculated solely on the basis of filterable particulate-only guarantees, then the calculations will not reflect additional emissions potential over and above the maximum 0.005 gr/scf filterable-only factor.

    Recent emission tests at the Vera Sun - Fort Dodge, Iowa plant show that condensible particulate constitutes the majority of emissions from grain handling and milling. Likewise, test results for the feed cooler show condensible particulate emissions greater than the filterable emissions, i.e., condensable particulate of 0.128 pounds/hour, as compared to filterable particulate of 0.016 pounds/hour. On a potential to emit basis, condensible particulate must still be considered in addition to the filterable-only emissions. While the amounts of condensible particulate over and above the filterable emissions of 0.005 gr/scf are not enormous, they contribute to under accounting of PM emissions large enough in the aggregate to push the proposed plant, as presently depicted, over the major source threshold for PM.

The "problem" that this comment addresses is created by the commenter and is not real. As noted in the comment, baghouses are very effective in controlling filterable particulate. The amount of condensable particulate from the feed coolers, which is "uncontrolled" with a baghouse, is not a significant factor in the total PM emissions compared to the emission limits that have been set for the cooler. Condensable particulate only becomes a potential problem if one presumes that the emissions of filterable particulate from these units will actually be at the level of the guarantee. Otherwise, the particulate emissions from these units, including both filterable and condensable particulate, are adequately addressed by the permit.

88. The feed cooler receives hot feed from the feed dryer. The hot feed will emit VOM from desorption of VOM containing liquids and from thermal decomposition as long as the material is at an elevated temperature, as is acknowledged in the application. As a result, the feed cooler exhaust should be subjected to testing for emissions of VOM and hazardous air pollutant emissions and to determine the actual gas discharge flow. This emission testing should be repeated on annual basis.

Initial emission testing of the feed cooler, as recommended by this comment, is required. The construction permit does not address subsequent periodic emission testing, which will be dealt

with during the processing of the operating permit for the plant. At that time, the results of the initial emissions tests can be considered when setting the requirements for periodic emissions testing.

89. The permit should set a maximum temperature for the hot feed entering the feed cooler and/or a ceiling on the temperature of the feed cooler implicit as a parameter monitored to ensure compliance with the VOM emission limit on a continuing basis.

It is not appropriate to set operational limits on the feed cooler as requested by this comment in the construction permit for the proposed plant. While the operating temperature of the cooler would theoretically affect VOM emissions, available data does not address the magnitude of this affect or show that the normal range of cooler operating temperature would be such that changes in temperature would meaningfully affect the level of VOM emissions. The need for requirements on the operating temperature of the cooler is more appropriately addressed during the review of the operating permit application for the plant, when actual operating information and VOM emission data for the cooler are available.

90. The induced draft fan on the feed cooler has the potential to cause entrainment of the exhaust from the feed dryers through enclosed conveyors. As a result, some potential for CO may be present. At least a single stack test should be performed to assess any CO emissions at this point from thermal decomposition of feed and entrained dryer exhaust.

Current information does not indicate that the feed cooler is a source of CO emissions. If information becomes available indicating testing for CO emissions is warranted, based on either inspection of the actual operation of the feed cooler or reports from other plants, emission testing may be required.

91. The plant process flow diagram shows a series of conveyers for the feed dryers and the feed cooler. The application does not show that these conveyors will be controlled. Like the feed cooler, these conveyors have the potential for emissions. However, there is no consideration of VOM, PM or CO emissions from these units. Without this information, the application is incomplete.

These conveyors will be controlled by the feed cooler baghouse and the emissions of these conveyors are addressed in the emission calculations for the feed cooler.

Handling of Wet Cake (Condition 2.5)

92. The emission calculations for handling of wet cake are based on testing conducted by the Natural Resource Group done in what seems an unheated indoor storage location in Minnesota in November. However, there does not appear to have been any effort to scale emissions to the proposed plant, which has a capacity of 110 million gallon per year. Also, in the information cited, half of the wet grains were four days old, but emissions of the most volatile organics can be expected to flash off very soon after the spent grains leave the screening location at elevated temperatures. Because of this reason, the referenced information on pad storage of wet cake cannot be considered as reflecting the full potential to

emissions. If outdoor pad storage of wet grains is used, then emissions characterization must consider maximum potential outdoor temperatures together with maximum potential process material temperature with introduction to pad storage. Also, without restrictions on the maximum storage time, the potential for VOM emissions from biological degradation of wet cake during storage must be considered. As a result, the permit must require "first in, first out" methods of dispatch for wet distiller's grains and other controls on the length of time for storage in order to properly limit the potential to emit for this emission unit.

The information submitted for VOM emissions from storage wet cake indicates that this testing was conservatively conducted with additional "handling" of the warm wet cake entering the storage area, to increase exposure to the air and maximize VOM emissions from the wet cake. These actions would act to compensate for any effect from the actual air temperature of the storage building, the ambient temperatures associated with an outdoor storage pad, and variations in the duration of storage.

It is not necessary for the permit to specify "first in, first out" handling of wet cake. This is an obvious practice for handling of wet cake (as well as many other commodities), as is minimizing the length of time that wet cake is stored at the plant.

93. If uncovered wet cake is stored outdoors, this practice would pose a risk for water pollution due to stormwater runoff from the pile. If such stormwater were then controlled in a retention pond, the potential emissions of the pond must also be considered, in addition to the emission from the outdoor storage pad itself.

Any outdoor storage or handling of wet cake at the plant must be conducted in a manner to control any stormwater runoff, which is subject to regulations that govern wastewater discharges from manufacturing plants. A common approach to stormwater management is collection of potentially contaminated storm runoff in a retention pond, to allow treatment if needed. Retention ponds at ethanol plants have not been identified as a source of concern for emissions.

Ethanol Loadout (Condition 2.7)

94. In its application, Big River Resources did not commit to use of submerged fill pipes or bottom loading for the ethanol loadout operations. The draft permit also would not require either of these techniques to reduce the generation of VOM emissions from these operations. Accordingly, the plant could engage in splash loading of transport vehicles, which would significantly increase loading losses to be controlled, without violating any limitation on the design basis for limiting the potential to emit.

Both tank truck and railcar ethanol loading at the proposed plant would be conducted with submerged filling or bottom loading. A condition has been included in the issued permit to specifically require these practices. However, as discussed in later comments, whether ethanol is loaded out by splash or submerged loading is only one factor in the calculation of VOM emissions from loadout, which are also affected by other factors such as the previous cargo of the transport vehicle and how that cargo was handled.

95. The draft permit would improperly excuse the ethanol loadout operations from having to use submerged loading pursuant to 35 IAC 215.122(a). This rule provides that loadout operations with a throughput of more than 40,000 gallons/day that would emit more than 8 lbs/hr of organic material must be equipped with submerged loading pipes, submerged fill, or a device that is equal or more effective in controlling emissions that is approved by the Illinois EPA. However, the Illinois EPA has not supported its determination that the control systems for these loadout operations will be as effective as use of submerged loading, nor is this determination supported by information in the application

The equivalency determination made by the Illinois EPA was not further explained because it is self-evident. The add-on control system for the loadout operations at the plant will be far more effective than use of submerged loading. Based on relevant USEPA emission factors, submerged loading may not have any effect on VOM emissions and at most only reduces emissions by 60 percent.[8] Accordingly, the plant is entitled to be excused from the regulatory requirement for submerged loading pursuant to 35 IAC 215.122(a). Moreover, pursuant to 35 IAC 215.122(c), use of submerged loading for ethanol loadout is also not required by rule because the vapor pressure of the denatured ethanol being handled is less than 2.5 psia at 70 ºF.

Whether the permit for the proposed plant, by permit condition, should require use of submerged loading to specifically control VOM emissions is a separate matter from whether use of submerged loading is required by rule. As already explained, even though the extent to which bottom filling would reduce VOM emissions from the different loadout operations is uncertain, the issued permit requires use of bottom filling. This is because bottom filling would be used at the proposed plant in actual practice.

96. The emission calculations for loadout of ethanol in the application significantly understate VOM emissions because they inappropriately use the saturation factor for "submerged loading - dedicated normal service" for the VOM content of the displaced air. However, Big River Resources did not certify that the transport vehicles to be loaded at the plant would be in dedicated service. The draft permit also would not require that transport vehicles actually be in "dedicated normal service."

The VOM emissions calculations for loadout of ethanol <u>by truck</u> have been revised to address the error identified by this comment. The revised calculations are based on a saturation factor of 1.0, as is appropriate for loadout when a vapor balance system is used for the prior cargo handled by the transport vehicle.[9] The saturation factor used to calculate VOM emissions from loadout by rail has not been changed. A saturation factor of 0.6 is correct when the prior cargo

---

[8] For loadout of organic liquids, the saturation factors for the displaced air range from 1.00 to 1.45 for splash loading and 0.50 to 1.00 for submerged loading, USEPA, *Compilation of Air Pollutant Emission Factors* (AP-42), Table 5.2-1. No reduction in VOM emissions occurs from submerged loading when an operation is in dedicated vapor balance service, as the saturation factors for both submerged and splash loading are 1.00. The greatest reduction in emissions occurs when an operation is not in vapor balance service, where the respective saturation factors are 1.45 and 0.60 for splash and submerged loading, with an emission reduction of 59 percent from use of submerged loading.

[9] When the prior cargo of a transport vehicle was unloaded with a vapor balance system, unless the vapor laden air in the cargo tank has been first purged to the atmosphere, the correct saturation factor when calculating VOM emissions when the cargo tank is next filled is 1.0. This factor is appropriate for the next filling of the tank irrespective of whether the splash or submerged loading is used. Refer to AP-42, Table 5.2.1.

of the transport vehicles was not unloaded with a vapor balance system and the current cargo is handled with submerged loading.

97. For trucks, the application indicates that emissions have been calculated on a "worst case basis," assuming that all trucks carried gasoline as their prior cargo before being loaded with ethanol. The recent loading history of a tank is an important factor in determining VOM emissions when it is filled.[10] Calculations of potential emissions must reflect the greatest amounts of emissions that can occur consistent with equipment design constraints and enforceable limitations on production, operation and emissions.

The VOM emissions from loadout of ethanol by truck have been calculated with the assumption that all tank trucks loaded at the plant previously handled gasoline. These calculations use the vapor pressure and molecular weight of gasoline, rather than ethanol. This addresses the much higher level of organic vapors in the "empty" cargo tank when the prior cargo of the tank truck was gasoline, rather than denatured ethanol, which has a much lower vapor pressure than gasoline.

The assumption that all tank trucks loaded at the plant previously handled gasoline is a worst-case assumption. In actual practice, it is probable that only a fraction of the tank trucks will have handled gasoline as their prior cargo. In Illinois, most gasoline is used in urban areas, where the population is concentrated, which is also where most of the ethanol from the plant would likely be used. Because of the nature of the gasoline market and distribution arrangements, it is also possible that most trucks loaded at the plant will not have previously handled gasoline and that most of the trucks serving the plant will only handle ethanol and shuttle between the plant and gasoline terminals. However, because some of the tank trucks loaded at the plant reasonably could have previously handled loads of gasoline, the VOM emissions calculation for loading trucks conservatively assume that all trucks loaded at the plant previously handled loads of gasoline.

98. Although the application indicates that tank trucks are assumed to previously have transported gasoline, the application is unclear on how that gasoline was handled. Whether that gasoline was handled with a vapor balance system is important. In particular, the emission calculations in the application incorrectly assume that the tank trucks would be in "normal service" for gasoline, whereas "vapor balance service" should be assumed. The norm is now "vapor balance service" for trucks delivering gasoline to service stations, with stations routinely equipped with vapor balance systems that capture the gasoline vapors displaced

---

[10] The recent loading history of a tank is a relevant factor for VOM emissions because it determines the nature of organic vapors in the "empty" tank that is being filled. If the tank previously held a nonvolatile liquid, such as fuel oil, it will contain essentially vapor-free air. If the tank just held a volatile liquid, such as gasoline, and has not been vented to remove vapors, the air in the tank will contain vapors from that volatile liquid, which will be displaced during filling along with newly generated vapors from the actual material currently being loaded into the tank. In this latter case, depending on the relative volatility of the two different materials, the previous liquid and the current liquid will have a different contribution to total emissions. In addition, Cargo carriers that transport only one material are designated as being in "dedicated service." Cargo tanks that handle multiple materials, with dissimilar properties, e.g., ethanol and gasoline, are designated as being "switch loaded." Actual practice varies based on a number of factors, notably, the compatibility of the materials, the nature of the markets and transportation patterns for materials.

during filling the tanks at the station.[11] Vapor balance service, and not normal service, is thus both the worst case and the most probable scenario that should be used to calculate potential emissions from loading of tank trucks at the plant.

As indicated in this comment, given current practice in Illinois for the handling of gasoline, it is appropriate to assume that all tank trucks serving the plant handled gasoline as their prior load and also that the gasoline was unloaded with a vapor balance system. This is another aspect of the conservative, worst-case assessment of emissions from the loadout operation. However, as previously discussed, this is not the "most probable scenario" for truck loadout.

99. "Vapor balance service" should also be assumed for the calculation of VOM emissions from loading railcars. The draft permit does not restrict the plant to only loading railcars that are in normal service, i.e., not in vapor balance service. If the plant would load railcars that are in dedicated service, the permit should specify whether all or some of the railcars must be in "normal service" with the emission calculation revised accordingly. Absent clear, enforceable provisions to assure that the assumptions used in calculating potential emissions will be present during actual operation of the plant, it should be assumed that all railcars will be in "vapor balance service" rather than "normal service."

Vapor balance systems are not used at the facilities at which ethanol from the plant would be delivered by rail. First, given the volumes of ethanol handled at such facilities, ethanol is often stored in floating roof tanks. This eliminates the displacement of vapor during filling of the receiving tank so that a vapor balance system would not provide any additional control of emissions. Second, the low vapor pressure of ethanol, as compared to gasoline, is such that vapor balance systems would not be as cost-effective for control of VOM emissions even if the ethanol was stored in fixed roof tanks.[12] The circumstances are different from those for distribution of gasoline by truck, for which vapor balance systems are used. Gasoline is handled by a regional fleet of trucks that transport gasoline to a large number of service stations, each storing relatively small amounts of gasoline in fixed roof tanks.

100. The potential emissions of the loadout operation are understated because the application incorrectly uses a saturation factor of 0.60 to calculate the uncontrolled loading losses. This factor is only appropriate for "submerged loading - normal service." The calculations should be based on the worst case mode of operation assuming "splash loading - vapor balance service." for tank trucks and "splash loading - normal service" for railcars. This practice is being followed for permitting of ethanol plants in other states.[13]

---

[11] "Vapor balance systems" control emissions by collecting the vapor containing air displaced from the receiving tank during unloading at a service station or other delivery destination and returning this air to the "empty" cargo tank. This reduces emissions at the delivery destination, since displaced vapors are not released to the atmosphere during unloading. However, the transport vehicle then carries the vapors back to the loading terminal or origin, where the vapors are controlled when the cargo tank is refilled. A cargo tank that has been unloaded with vapor balance service normally is saturated with organic vapors. The presence of these vapors when the cargo tank is refilled results in greater generation of emissions than occurs when the cargo tank is in "normal service." i.e., was not unloaded with a vapor balance system.

[12] Vapor balance systems for railcars would entail costs for both the elements of the vapor balance system at the receiving facilities and elements of the system on each railcar that would be connected to these systems.

[13] The Michigan Department of Environmental Quality has used a saturation factor of 1.0 in recent permits for ethanol plants, including the proposed Liberty Renewable Fuels plant in Ithaca, Michigan, which would be designed by ICM.

The emission calculations for the truck loadout operation have been corrected in response to this comment. A saturation factor of 1.00 is now used for truck loadout, consistent with use of "submerged loading – vapor balance service," rather than 0.60 for "submerged loading – normal service."[14] However, the saturation factor used in the calculations for railcar loadout has not been changed. A factor of 0.60 is correct for railcar loadout because vapor balance systems are not used at the facilities that receive ethanol by rail.

101. The VOM emission calculation for the loadout operations are flawed because they assume 100 percent capture and do not consider leaks. The application does not contain adequate support for this assumption. While the application states that these calculations follow Section 5.2 of USEPA's *Compilation of Air Pollutant Emission Factors*, "Transportation and Marketing of Petroleum Liquids," this is not the case for capture efficiency. The relevant portion of AP-42 indicates "…only 70-90 percent of the displaced vapors reach the control device, because of leakage from both the tank truck and collection system. The collection efficiency should be assumed to be 90 percent for tanker trucks required to pass an annual leak test. Otherwise, 70 percent should be assumed." USEPA AP-42 Emission Factors for Transportation and Marketing of Petroleum Liquids, Section 5.2.2.1.1, Loading Losses. The emissions calculations in the application and the provisions in the draft permit do not contain support for assuming 100 percent capture, nor does the draft permit include provisions that would ensure that 100 percent capture is achieved.

In response to this comment, the VOM emissions calculations for the ethanol loadout operations have been revised to address efficiency of the vapor collection systems, to account for leakage. For truck loadout, a capture efficiency of 98.7 percent is now used. For rail loadout, a capture efficiency of 95 percent is now specified. The USEPA's recommendations in AP-42 for capture efficiency of vapor collection systems are based on out-dated information from the late 1970's and should not be relied upon. Newer data from the 1990s shows that vapor collection systems achieve approximately 99 percent capture of emissions when accompanied by a requirement for annual vapor tightness testing and otherwise about 96 percent capture efficiency.[15]

102. The permit should require that all transport vehicles loaded at the plant meet appropriate capture efficiency and vapor "tightness" requirements, with compliance verified by monitoring and recordkeeping.

The permit generally requires that the vapor collection systems for the loadout operations be

---

[14] This error was likely the result of the terminology in AP-42, where the meaning of the term "normal service" is "not in vapor balance service." As already discussed, due to changes in practices for unloading gasoline at service stations, at the present time gasoline is normally or routinely handled with vapor balance systems.

[15] Data from the early 1990's reviewed by USEPA shows that annual vapor tightness testing programs achieve between 98.7 and 99.2 percent collection efficiency. As further explained by USEPA, earlier data showed lower levels of collection efficiency. "Based on field tests in the late 1970's, an annual vapor tightness testing program was estimated to reduce the leakage rate from baseline levels at 30 percent leakage to about 10 percent leakage." USEPA, *Gasoline Distribution Industry (Stage 1) - Background Information for Promulgated Standards*, EPA-453/R-94-002b, November 1994. More recent data assembled for USEPA indicates that the control efficiency of vapor balance systems range from 93 to 100 percent, with a recommended emission factor that reflects a capture efficiency of 95.9 percent. *Emission Inventory Improvement Program*, Volume III: Chapter 11, "Gasoline Marketing (Stage I and Stage II)," Eastern Research Group, January 2001.

properly operated and that loadout be conducted in accordance with good air pollution control practices to minimize emissions. Recordkeeping is also required to document proper operation and maintenance of loadout equipment and associated control systems. For railcar loadout, given the nature of fittings on railcar, the issued permit also includes specific provisions for routine inspection of the connection between the railcar and the vapor collection system to verify a proper seal as needed for proper operation of the system.

The permit does not need to include specific provisions to address the leak tightness of tank trucks because of the assumption that is being made that the prior cargo handled by tank trucks was gasoline. A corollary of this assumption is that the trucks that actually handled gasoline are subject to regulatory requirements for tank trucks handling gasoline. In other words, as the emission calculations for truck loadout assume that all tank trucks serving the plant previously handled gasoline using vapor balance systems, as now commonly required or used at service stations, the permit also relies upon the related regulatory requirements for vapor tightness that would also apply to these tank trucks. These rules generally require tank trucks that transport gasoline to pass annual vapor tightness tests. These rules also set specific requirements for vapor collection systems on tank trucks and set deadlines for repair of leaks in these systems.

The permit also does not need to include specific provisions to address the leak tightness of tank trucks that did not actually handle gasoline as their prior cargo, but instead handled ethanol. As such tank trucks only handle ethanol, these trucks will not be subject to the regulatory requirements for transport of gasoline. However, compliance with those requirements is not needed to achieve the level of capture efficiency that is necessary to meet the specified rate of VOM emissions for loadout by truck. This is because the vapor pressure of ethanol is lower than that of gasoline, which has been used in the VOM emissions calculations for truck loadout. In other words, because the level of "uncontrolled" emissions from handling ethanol is lower than that of gasoline, when the prior cargo of a truck was ethanol, the capture system need not be as effective to achieve levels of VOM emissions to the atmosphere that are equal to or lower than those when gasoline was previously handled by a tank truck.

103. The draft permit would not prohibit the plant from loading a tank truck or railcar if it has not passed an annual test for vapor tightness or if components of the vapor collection system on the vehicle itself (i.e., (piping, seals, valves, vacuum breakers, etc.) are not properly operating. Effective operation of the vapor collection systems depends on both the fixed components at the loadout rack as well as elements on the transport vehicle. Allowing the plant to load trucks and railcars with vapor leaks will result in significantly higher VOM emissions from the loadout operations.

Whether the permit may allow loading of transport vehicles with less than complete capture of displaced vapors depends upon whether achievement of complete capture is relied upon by the permit and the emission limits in the permit account for leakage from the vapor collection systems. As already discussed, the emission limits for the loadout operations in the issued permit account for emissions from leakage from the vapor collection systems.

104. The VOM emissions from the loadout operations will exceed the limits in the draft permit, i.e., 0.0864 pounds per 1000 gallons loaded by truck and 2.49 tons per year, if properly

calculated in accordance with the various comments. The additional VOM emissions, 2.98 tons per year,[16] will put the plant over the 100 ton/year major source threshold. In addition, the controlled VOM factor of and the incorrect assumption that all "emissions not captured or controlled" have been considered must be corrected. Also, the HAP emission calculation must be amended to account for the increase in HAP associated with the corrected, higher VOC emission estimate from the truck loading rack.

The correction of the errors in the emission calculations for the loadout operations does not result in the proposed plant becoming a major source. With the various corrections to the emission calculations for ethanol loadout, the permitted VOM emissions for these operations in the issued permit are 5.65 tons/year. The emission limits for HAPs are also higher. To account for the additional emissions from loadout, the limits for VOM emissions from the dryer/oxidizer/boiler systems have been lowered to reduce annual VOM emissions by a few tons. As a result, the proposed plant still will not be a major source of emissions. The increases in HAP emissions are not large enough to need any adjustment.

The conservative nature of these emission calculations for the loadout of ethanol should also be noted. The calculations assume that all trucks loaded with ethanol at the plant will previously have handled a cargo of gasoline. The calculations conservatively account for less that complete capture of vapors displaced from cargo tanks during loading. The calculations also assume that the flare will only provide 98 percent control, which is a minimum value for the performance of a properly operated, well-designed flare. USEPA reports that the average value of control efficiency for a properly operated flare is well over 99 percent.[17]

105. If the permit does not require that all tanker trucks pass an annual leak test before being loaded at the plant, then the fugitive emissions should be determined assuming only 70% capture efficiency and annual VOM emissions will be far in excess of the amount allowed by the draft permit.

As previously explained, it is not appropriate modern capture systems for loadout of organic liquids achieve better than 70% capture of VOM emissions even when not accompanied by an annual test for leak-tightness of the transport vehicles. The emission calculations underlying the issued permit are based on appropriate values for the minimum level of capture efficiency that may be relied upon given the practices and circumstances of truck and rail loadout at the proposed plant.

---

[16] Using a saturation factor of 1.0, rather than 0.6, the uncontrolled emission factor for truck loadout is 7.20 lbs VOM per 1000 gallons loaded for a truck that previously hauled gasoline. The uncontrolled VOM emissions for loadout by truck will be 144 tons per year for loading of 40 million gallons (assuming that the permit will limit shipments by tank truck to 40 million gallons per year). With 98.7% capture efficiency (assuming all trucks have passed an annual leak test, as would be required by the issued permit) 1.3% of 144 tons will be lost as fugitive emissions, or 1.87 tons will not be captured. A total of 142.1 tons will be captured and ducted to the flare, with assumed 98% destruction, for controlled VOM emissions of 2.84 tons per year. Combining the fugitive and controlled emission, total VOM emissions from truck loadout will be 4.71 tons per year. After accounting for the VOM emissions from rail loadout, the overall VOM emissions from loadout will be2.98 tons more than the 2.49 tons that would be allowed each year by the draft permit.

[17] USEPA has determined that the average efficiency of flares operated to comply with 40 CFR 63.11(b) is well over 99 percent. 40 CFR 63.11(b) has similar requirements as 40 CFR 60.18, which the flares at the proposed plant must meet. USEPA, *Gasoline Distribution Industry (Stage 1) - Background Information for Promulgated Standards*, EPA-453/R-94-002b, November 1994.

106. In addition to requiring loading rack and the biomethanator flares to comply with the relevant provisions of the NSPS specifically for flare systems, 40 CFR 60.18, the permit should also require compliance with the General Provisions of the NSPS, 40 CFR 60, Subpart A for the flares.

The permit requires the flares at the proposed plant be designed and operated to comply with the relevant provisions of the NSPS for flares because these provisions are a commonly accepted statement of proper design and operation of a flare to control emissions. In addition, the flares at the plant would not otherwise have been subject to these requirements as a matter of rule, i.e., they do not control NSPS-affected units. However, this rationale does not support generally applying other requirements of the NSPS, as found elsewhere in the General Provisions of the NSPS, 40 CFR 60, Subpart A, to these flares.

107. For the loadout operation, a narrative explanation stating that emission limits are "based on information in the application including … maximum ethanol loadout to truck (40 million gallons per year)" is not enforceable. In fact, the emission calculations for fugitive PM from roadways are based on tank trucks handling up to 66 million gallons of ethanol each year. The permit should restrict the number and type of vehicles that are loaded with ethanol at the proposed plant.

The issued permit explicitly limits load out of ethanol from the plant by truck to no more than 40 million gallons per year. (See Condition 2.7.5(f).) The revised emissions calculations submitted for PM emissions from roadways also use this value for the maximum amount of material that would be handled by tank trucks, which corrects the discrepancy between the roadway and loadout emissions calculations identified in this comment.

108. The application did not properly address PM emissions from the ethanol loadout operations. While the flare that controls VOM emissions from these operations will be of "smokeless design," this does not mean zero PM emissions, as was assumed in the application. At a minimum, PM emissions should have been estimated using the emission factor for total PM (filterable and condensible) from combustion of natural gas. The flaring of gasoline and ethanol vapors should emit at least the same amount of PM as combustion of natural gas, on a heat input basis.

The draft permit accounted for PM emissions from the flare with emissions calculated in a manner consistent with that recommended by this comment. These provisions are also included in the issued permit.

Biomethanator (Condition 2.9)

109. For the flare, the application started from the VOM emission factor from AP-42, 0.14 lbs of total organic carbon (TOC) per million Btu, and adjusted the factor based on the methane and ethane content of the flared gas (63%). This reduced the emission factor to 0.052 lb VOM/million Btu, which was then used to calculate VOM emissions from the flare. This adjustment was made on an assumption that only regulated VOM should be considered in the

VOM emissions of the flare.

This approach is flawed. It underestimates VOM emissions from this flare because it takes full credit for what USEPA indicated in AP-42 was 8 volume percent emissions of ethane/ethylene, but ethylene is a VOM. Further, ethane is not a likely product of incomplete combustion of ethanol vapors because of the presence of oxygen and its position in the ethanol molecule. The VOM emissions of this flare should be recalculated using the AP42 factor without any adjustments.

The adjustment to the AP-42 emission factor for emissions from flaring of waste gas, as addressed by this comment, is required. This is because AP-42 provides an emission factor, as cited above, in terms of total hydrocarbons (THC). The adjustment was properly made based on the supporting data for the emission factor that is provided in AP-42. While one can speculate on the specific effects of burning different organic compounds on the VOM and THC emissions of a flare burning waste gas, this does not provide a sound basis to treat methane as a VOM, as this comment is effectively recommending.

Incidentally, the VOM emissions from vapors collected during ethanol loadout were not calculated with the AP-42 emission factor addressed in these comments. The VOM emissions from the vapors displaced during loadout were conservatively calculated based on the loadout flare achieving 98 percent destruction of the captured vapors. This is based on information in AP-42 and other USEPA documents indicating that properly operated flares achieve at least 98 percent efficiency, meaning that hydrocarbon emissions are less than 2 percent of hydrocarbons in the gas stream sent to the flare.

Cooling Tower (Condition 2.10)

110. To assure compliance with applicable emission limits for the cooling tower, the permit must require monitoring and periodic inspections of the cooling tower. The permit should also require monthly monitoring of the total dissolved solids (TDS) content of the circulating cooling water to ensure that the TDS content does not exceed 2500 ppm. The tower must also be subject to a requirement that the TDS content of the cooling water does not exceed 2500 ppm.

The issued permit includes additional requirements for the cooling tower, as generally recommended by this comment.

111. The permit must require cooling tower blowdown and appropriate water addition whenever the TDS content in the circulating cooling water reaches 2500 ppm.

Big River Resources is generally required to take necessary steps to operate <u>all</u> emission units at the plant in compliance with applicable limits and control requirements. For the cooling tower, it is not necessary or appropriate to specifically identify the particular action recommended by this comment, particularly as it would suggest that the TDS content of the cooling water is allowed to exceed 2500 ppm before corrective action is initiated.

112. The permit should require quarterly measurements of the ethanol content of cooling water, measured at a point in the distillation area directly downstream of the condensers. This is needed to verify that that the condensers are not leaking, due to corrosion or other degradation.

It is not appropriate for the construction permit for the proposed plant to mandate specific requirements of the type suggested in this comment. In the absence of actual experience at a specific plant demonstrating failure to properly implement particular maintenance practices, a permit is issued based upon the presumption that all equipment will be properly maintained and repaired as necessary to prevent or promptly correct failures that would lead to increased emissions, such as the type of equipment failures described in this comment. This includes not only maintaining the integrity of heat exchangers, but also maintaining the integrity of other features at a plant, including enclosures, tanks, ductwork, fans, and stacks.

113. The permit should limit the water recirculation rate of the cooling tower to 3 million gallons per hour, as was used in emission calculations, to properly limit the potential emissions of the cooling tower. Based on the design drawing in the application, the cooling tower will have four recirculation pumps, with an hourly capacity of 3.48 million gallons per hour. Therefore, the permit must physically limit the potential emissions by limiting process rate of the cooling tower or the PM emissions of the tower must be considered more than 13.7 tons/year, thus putting the plant over the major source threshold.

The cooling tower is an ancillary operation at the source, which will function to support production of ethanol. As such, the "extent of operation" of the cooling tower is adequately addressed by the limits on the ethanol production of the plant. It is not necessary or appropriate to also constrain the operation of the plant by separately limiting the amount of water that may be circulated through the cooling tower. The design of the cooling tower, with four separate pumps whose total capacity is 3.48 million gallons/hour, does not demonstrate intent to operate the cooling tower at greater than 3 million gallons/hour on an annual basis. Rather, the presence of four pumps enables normal operation of the cooling tower with three pumps, at a recirculation rate that is less than used in the emission calculations, with the fourth pump either being on reserve as a spare or being out of service for maintenance.

Roadway Emissions (Condition 2.11)

114. The emission calculations in the application for fugitive PM emissions from roadways are incorrectly based on all trucks serving the proposed plant traveling 1.0 mile on plant roads. Condition 2.11.1 of the draft permit also incorrectly states that the plant would have 1.0 mile of roadways. However, a review of the site plan for the proposed plant shows that trucks that handle ethanol, denaturant and feed would travel a much longer distance. Tank trucks would travel about 2.5 miles and feed trucks would travel almost 2.9 miles. Based on this corrected analysis, assuming that all materials are handled by truck, the annual PM emissions from plant roadways would be either 45.4 or 59.1 tons, depending on whether a silt loading of 0.4 or 0.6 gr/meter^2. Either scenario would push the plant over the 100 ton major source threshold.

The errors identified by this comment have been corrected. Big River Resources has submitted revised calculations for PM emissions from plant roadways that are based on grain trucks traveling 0.8 miles and other trucks traveling 2.9 miles. With the revised calculations, permitted annual PM emissions from roadways are now 36.8 tons, rather than 27.0 tons. The increase in PM emissions is not as large as projected by this comment because of other elements of the calculations. In particular, only some of the ethanol produced by the plant would be shipped by truck and the revised calculations also reduced the amount of such shipments. Accordingly, the correction of the calculations for PM emissions from roadways does not result in the plant becoming a major source for purposes of PSD.

The provision in the issued permit describing plant roadways also no longer specifies the length of plant roadways. Given the location of the plant inside the rail loop associated with the existing grain elevator that would serve the plant, tank trucks and trucks handling feed travel much further than the grain trucks, which will unload at the elevator and will not travel on to the ethanol plant proper.

115. When calculating potential PM emissions from the roadways at the proposed plant, the application used a silt loading factor of 0.4 gram/meter^2, which yielded potential PM emissions of 36.77 tons/yr. However, the use of a factor of 0.4 gram/meter^2 for the average silt loading on roadways at an industrial plant is not correct and is not supported by AP-42, as incorrectly claimed in the application. Even if plant roadways were public roads, the lowest silt loading provided by USEPA in AP-42 as the "ubiquitous baseline" for public roads with less than 500 average daily traffic volume is 0.6 gram/meter^2. This factor is also subject to multipliers during the winter if roads are treated for anti-skidding. Calculation of roadway emissions for the proposed plant, using a silt loading of 0.6 gram/meter^2 and all other factors being the same, yields a level of potential PM emissions from the plant that would make the plant a major source for PM emissions.

The supplemental information submitted by Big River Resources for the proposed plants includes revised emission calculations for roadways that are based upon a silt loading of 0.6 gram/meter^2. In conjunction with this change, Big River Resources rebalanced or reallocated the PM emissions of different operations at the plant to maintain its status as a non-major source under the PSD rules.

The issued permit also requires that measurements be conducted for the silt loading on roadways at the plant. These measurements, together with other provisions of the permit, should assure that the PM emissions of roadways at the plant are appropriately controlled so as to maintain PM emissions with the limits set by the permit. In this regard, the roadways at the plant are not public roads and will be subject to requirements for regular sweeping, flushing or other dust control measures to minimize dust emissions.

116. Use of a silt loading of 0.4 gram/meter^2 also is not supported by actual experience. A review of the data for silt loading used for other grain processing plants and the permitting practices of other Midwestern states shows roadway silt loadings that range from 0.5 to 7.4 gram/meter^2. This review shows that the 0.4 gram/meter^2 silt loading used for the proposed plant is too low.

The material provided with this comment confirms the need for measurement of the actual silt loadings on plant roadways, as required by the issued permit.

117. The draft permit does not contains measures that will ensure that the 0.4 gram/meter^2 silt loading and the associated limit on PM emissions from roadways will actually be met. There are no specific requirements for periodic sweeping and cleaning of roadways that would allow such a level of silt loading to be achieved. Mere reliance on a future plan, with applicant-discretionary measures that are not enforceable in practice, cannot ensure compliance with the associated emission limit. At a minimum, if a permit is issued based on a silt loading of 0.4 gram/meter^2, the permit must require that such silt loading be achieved in practice, together with quarterly testing requirements.

The issued permit includes additional requirements for the fugitive dust control program to assure that the program developed by the plant includes emission control measures that should assure that associated limits on PM emissions are met. Given the variety of control measures that could be used by the plant, for a plant that has not even been constructed, it is not appropriate for the permit to specify particular measures that must be used to control PM emissions from roadways.

The reliance upon a fugitive dust control that is developed and maintained by Big River Resources is appropriate. This requires effective control of emissions while still providing necessary flexibility to address the factors that affect the emissions of fugitive dust from roadways, i.e., the volume and type of vehicle traffic, the efficacy of the selected treatment method(s), and weather conditions. In particular, a set frequency of road cleaning would not address: (1) Periods when there is not truck traffic on roadways, e.g., Sundays; (2) Variation in the effectiveness of different cleaning techniques; and (3) Weather conditions that control dust, i.e., precipitation, or increase dust, i.e., hot weather. A plan can be developed and maintained to account for these factors. For example, during hot weather when the volume of truck traffic is high, Big River Resources would be required to clean roadways at an appropriate frequency to control dust during such conditions, perhaps even cleaning roads several times per day.

118. The calculations for fugitive PM emissions from plant roadways in the application are based on values for vehicle miles traveled (VMT) each year that reflect trucks handling up to 66 million gallons denatured ethanol product (60% of plant capacity) and up to 3.85 million gallons of denaturant (70% of plant capacity). They also reflect truck shipments for 356,880 tons of dry feed (100% of plant capacity) but do not account for any shipments of wet feed by truck. However, the draft permit does not contain limits that would ensure that these levels would not be exceeded in practice. In the absence of a physical limit on the potential to emit for the fugitive PM from roadways, emission calculations should be based on use of trucks for all shipments of material, since this is a possible mode of operation that is within the scope of the design of the plant.

The revised calculations for PM emissions from roadways conservatively, i.e., generously, account for the truck traffic at the proposed plant assuming that all grain is received by truck. The issued permit also limits the amount of ethanol that may be shipped by truck, as related to the VOM emissions from this operation. Accordingly, it is not necessary to further explicitly limit the amount of truck traffic at the plant. In particular, shipment of wet feed would be

accompanied by a reduction in the amount of dry feed shipped, as well as reduced emissions from drying of feed. In addition, as explained in response to the above comment, the permit effectively requires that Big River Resources control PM emissions from roadways based on 10 percent more than the maximum volume of truck traffic that the plant would handle.

119. The draft permit would not require records for truck VMT. Reliance on "assumptions" about typical and maximum quantity of vehicle traffic at the plant, as addressed by Condition 2.11.9(a), would not yield accurate determination of fugitive PM emissions for purposes determining with the applicable emission limits.

The permit for the proposed plant requires records from which an accurate determination of truck VMT may be calculated. The amount of material handled by truck is the difference between the total amount of each type of material handled and the amount handled by rail, for which records must be kept. The VMT associated with each material handled by truck is calculated using information for the trip length for the material and the average load carried by the trucks handling the material.

Other Provisions of the Permit

120. The plant can be expected to have natural gas fired space heating units in various buildings. Although these units may be exempt from permitting, they still count towards the total emissions of the plant for comparison with the major source threshold. Big River Resources must disclose the total emissions associated with such space heating units as part of a complete application.

The usage of natural gas by space heating units at the plant is addressed by the permit, as the permit limits total usage of natural gas by the plant and the total emissions of different pollutants from the plant.

OTHER COMMENTS CONCERNING THE PROPOSED PLANT

121. The proposed plant is an excellent chance for growth and prosperity in Galva and the surrounding area.

122. The project is desirable because it will increase the price for corn, supporting local farms and the rural economy.

123. I look forward to investing in this project, which will add to the value of the corn that I grow.

124. The proposed plant will use modern "dry mill" technology, which does not have the odors problems associated with older plants using wet mill technology.

125. The plant is important because the ethanol made by the plant is an alternative to fossil fuel. The United States needs to step up production of alternative fuels to reduce dependence on foreign oil and because the reserves of fossil fuel are limited.

126. While the project would help reduce our country's dependence on foreign oil, Big River should commit to using local, union workers to build the plant. This area has plenty of construction workers who are more than capable of building this plant and it is in the interest of the local economy to use these workers. Accordingly, I'm currently neutral on the proposed plant.

127. If the proposed plant would be built farther out in the country, it would be fine as it benefits farmers. But I don't want it built next to the neighborhood where I live.

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