# Responsiveness Summary
# Sunflower Electric Power Corporation
# Holcomb Expansion
# Air Quality Construction Permit Application

Kansas Department of Health and Environment
Bureau of Air and Radiation
Air Permitting Section

October 17, 2007

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## TABLES

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## List of Acronyms

| **Acronym** | **Description** |
|---|---|
| AAQIR | Ambient Air Quality Impact Report |
| ACC | Air Cooled Condenser |
| ACI | Activated Carbon Injection |
| AEP | American Electric Power |
| BACT | Best Available Control Technology |
| BAPC | Bureau of Air Pollution Control |
| BAR | Bureau of Air and Radiation |
| Btu | British thermal unit |
| CAA | Federal Clean Air Act |
| CDS | Circulating Dry Scrubber |
| CEMS | Continuous Emission Monitor System |
| CFB | Circulating Fluidized Bed |
| CO | Carbon Monoxide |
| $CO_2$ | Carbon Dioxide |
| COM | Continuous Opacity Monitor |
| CPM | Condensable Particulate Matter |
| DOE | Department of Energy |
| EAB | Environmental Appeals Board |
| EPA | Environmental Protection Agency |
| ESP | Electrostatic Precipitator |
| FGD | Flue Gas Desulfurization |
| FSI | Furnace Sorbent Injection |
| GWh | Gigawatt Hour |
| H1 | Holcomb Unit 1 Electric Steam Generator |
| H2 | Holcomb Unit 2 Electric Steam Generator |
| H3 | Holcomb Unit 3 Electric Steam Generator |
| $H_2O_2$ | Hydrogen Peroxide |
| HAP | Hazardous Air Pollutant |
| Hg | Mercury |
| ICR | Information Collection Request |
| IGCC | Integrated Gasification Combined Cycle |
| IPA | Isopropanol |

## List of Acronyms

| **Acronym** | **Description** |
|---|---|
| IPP | Intermountain Power Project |
| KDHE | Kansas Department of Health and Environment |
| KWh | Kilowatt hours |
| LAER | Lowest Achievable Emission Rate |
| Lb | Pound |
| LNB | Low $NO_x$ Burner |
| LSD | Lime Spray Dryer |
| MEL | Magnesium Enhanced Lime |
| mmBtu | Million Btu |
| MW | Megawatt |
| MWh | Megawatt hours |
| NAAQS | National Ambient Air Quality Standards |
| NETL | National Energy Technology Laboratory |
| $NO_X$ | Oxides of Nitrogen |
| NPDES | National Pollutant Discharge Elimination System (Federal Water Pollution Control Rules) |
| NSPS | New Source Performance Standard |
| NSR | New Source Review |
| $O_2$ | Oxygen |
| PADEP | Pennsylvania Department of Environmental Protection |
| PIC | Product of Incomplete Combustion |
| PM | Particulate Matter |
| $PM_{10}$ | PM with an aerodynamic diameter of less than or equal to 10 microns |
| $PM_{2.5}$ | PM with an aerodynamic diameter of less than or equal to 2.5 microns |
| PC | Pulverized Coal |
| PRB | Power River Basin |
| PSD | Prevention of Significant Deterioration |
| RACT | Reasonable Available Control Technology |
| RTO | Regenerative Thermal Oxidizer |

## List of Acronyms

| Acronym | Description |
| --- | --- |
| SAM | Sulfuric Acid Mist |
| SCC | Sierra Club Comment |
| SCR | Selective Catalytic Reduction |
| SDA | Spray Dryer Absorber |
| SIBC | Sunflower Integrated Bioenergy Center |
| SIP | State Implementation Plan |
| $SO_2$ | Sulfur Dioxide |
| $SO_3$ | Sulfur Trioxide |
| SOFA | Separated Overfire Air |
| TDD | Technical Development Document |
| TCEQ | Texas Commission on Environmental Quality |
| TXI | A Dallas, Texas based energy company |
| TXU | Texas Industries, Inc., a major producer of steel and cement/concrete products for construction |
| VOC | Volatile Organic Compound |

# I. RECOMMENDATION

The Kansas Department of Health and Environment (KDHE) Bureau of Air and Radiation (BAR) recommends the issuance of an Air Quality Construction Permit to Sunflower Electric Power Corporation (Sunflower) for construction of two (2) new 700 megawatt (MW) coal-fired steam generating units and associated ancillary equipment (Holcomb expansion) at their generating station located in Holcomb, Kansas.

The recommended final permit for the project identifies the applicable rules governing emissions from the plant, and establishes enforceable limitations on its emissions. The permit also establishes appropriate compliance procedures, including requirements for emissions testing, continuous emission monitoring, recordkeeping and reporting. Sunflower will be required to carry out these procedures on an ongoing basis to demonstrate that the plant is operating within the limitations established by the permit and that emissions are being properly controlled.

The permit related documents can be found at the BAR website address:

http://www.kdheks.gov/news/

or contact: (785) 296-1500.

# II. PROJECT DESCRIPTION

On February 6, 2006, the KDHE BAR received an application from Sunflower requesting a permit for the Holcomb expansion project. Sunflower's original application included three (3) generating units. A letter received June 18, 2007 formally removed one (1) generating unit from consideration.

Sunflower plans to install and operate two steam generators located in Holcomb, Finney County, Kansas. The existing facility will install Holcomb Units 2 and 3 (H2 and H3) adjacent to the existing Holcomb coal-fired generating unit (H1) owned by Sunflower.

Each new unit is a super critical 700 megawatt (MW) (6501 mmBtu/hr heat input) pulverized coal (PC) fired boiler. The existing coal, lime, and ash handling equipment with the addition of equipment to double throughput capability will be utilized. Two new cooling towers, two natural gas fired auxiliary boilers and two emergency generators shall be added. The H2 and H3 steam generators will fire Powder River Basin (PRB) sub-bituminous coal, low sulfur bituminous coal as primary fuel and natural gas as a backup fuel.

## III. KDHE PERMIT CONSIDERATIONS

The two new generating units proposed by Sunflower are considered a major modification of a major stationary source because one or more of the Prevention of Significant Deterioration (PSD) regulated air pollutants from the proposed activity exceeds the significance level(s). Therefore, KDHE permit considerations must follow the PSD Air Quality Construction Permit requirements.

PSD does not prevent sources from increasing emissions. PSD is designed to:

1. protect public health;

2. preserve, protect, and enhance the air quality in national parks, national wilderness areas, national monument, national seashores, and other areas of special national or regional natural, recreational, scenic, or historic value;

3. insure that economic growth will occur in a manner consistent with the preservation of existing clean air resources; and

4. assure that any decision to permit increased air pollution in any area to which this section applies is made only after careful evaluation of all the consequences of such a decision and after adequate procedural opportunities for informed public participation in the decision making process.

PSD applies to new major sources or major modifications at existing sources for pollutants where the area the source is located is in attainment or unclassifiable with the National Ambient Air Quality Standards (NAAQS). It requires the following:

1. installation of the “Best Available Control Technology” (BACT);

2. an air quality analysis;

3. an additional impacts analysis; and

4. public involvement.

### A. Best Available Control Technology (BACT)

BACT is an emissions limitation which is based on the maximum degree of control that can be achieved. It is a case-by case decision that considers energy, environmental, and economic impacts. BACT can be add-on control equipment or modification of the production processes or methods. This includes fuel cleaning or treatment and innovative fuel combustion techniques. BACT may be a design, equipment, work practice or operation standard if imposition of an emissions standard is infeasible.

BACT applies to each new or modified affected emissions unit and pollutant emitting activity at the source for each pollutant having a potential to emit, or an increase in potential to emit, above the PSD significance level(s). For the proposed Sunflower generating units, the increase in potential-to-emit is above the PSD significance level for $NO_x$, $SO_2$, CO, PM/$PM_{10}$, sulfuric acid mist, lead, and VOCs and was reviewed under the PSD regulations.

For the Sunflower pulverized coal fired electric steam generating units, BACT is:

- For oxides of nitrogen ($NO_x$), the steam generators shall use low-$NO_x$ burners (LNB) and separated over-fire air (SOFA) equipment along with selective catalytic reduction (SCR).
- For carbon monoxide (CO) BACT is good combustion practices.
- For sulfur dioxide ($SO_2$), the steam generators shall use a dry flue gas desulfurization (dry FGD) system and low sulfur coal.
- For volatile organic compounds (VOC) BACT is good combustion practices.
- For particulate matter (PM), BACT is a fabric filter.
- For particulate matter with aerodynamic diameter less than 10 microns ($PM_{10}$), BACT is a fabric filter.
- For total elemental lead (Pb), BACT is a fabric filter.
- For total sulfuric acid ($H_2SO_4$), BACT is a dry FGD.
- Although mercury (Hg) is no longer considered a pollutant under PSD, Sunflower has agreed to install activated carbon injection to control Hg emissions far more than required by Federal or State regulations.

## B. Ambient Air Quality Analysis

The main purpose of the air quality analysis is to demonstrate that new emissions emitted from a proposed major stationary source or major modification, in conjunction with other applicable emissions increases and decreases from existing sources, will not cause or contribute to a violation of any applicable national ambient air quality standard (NAAQS) in any air quality control region; or any applicable maximum allowable increase over the baseline concentration in any area.

Sunflower used EPA approved dispersion modeling guidelines to predict the ambient air impacts. The ISCST3 model was used to determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period resulting from various operating loads.

All modeled concentrations for $NO_x$, CO, and lead were less than the modeling significance thresholds for all averaging periods. However this screening analysis that eliminated $NO_x$, CO and lead from further analyses indicated that additional air quality analysis was required to determine whether potential $SO_2$ and $PM_{10}$ emissions from the proposed project are expected to cause a significant deterioration of air quality in the Holcomb, Kansas area. A full impact analysis was required for $SO_2$ and $PM_{10}$ to demonstrate compliance with the PSD increment and NAAQS.

The expanded receptor grid was established to determine the entire significant impact area, and all $SO_2$ increment and NAAQS sources were included in the modeling runs. All maximum concentrations were below the PSD increment. All results, when combined with ambient background concentrations, were below the NAAQS.

The $PM_{10}$ screening model indicated that concentrations dropped below the PSD Modeling Significance Threshold well within the existing receptor grid of 10 kilometers. Therefore, an expanded receptor grid was not required for $PM_{10}$.

Although there were modeled 24-hour and annual PSD increment exceedances for $PM_{10}$, the construction and operation of H2, H3, and H4 would not cause or contribute significantly to the modeled exceedances. Therefore, no further modeling is required for Class II increment or NAAQS compliance.

The application was updated by a letter received June 18, 2007 to remove one of the originally proposed units. Additional modeling data (AERMOD) was received July 3, 2007 to demonstrate that the reduction in emissions and ambient air boundary revisions did not affect the NAAQS or PSD increment.

## C. Additional Impact Analysis

The additional impacts analysis assesses the impacts of air, ground and water pollution on soils, vegetation, and visibility caused by any increase in emissions of any regulated pollutant from the source or modification under review, and from associated growth. Associated growth is industrial, commercial, and residential growth that will occur in the area due to the source. The results of the Sunflower analysis are summarized below.

### 1. Visibility Impairment Analysis

Sunflower conducted a visibility degradation analysis for the $NO_x$ and particulate matter emissions from the proposed modification. A visibility analysis is performed for Class I (visibility-sensitive) areas located within 100 kilometers of a proposed facility. There are no Class I areas in Kansas. The analysis was done at nearest PSD Class I area, which is Great Sand Dunes National Wilderness Area which is located approximately 400 kilometers west of Holcomb. The VISCREEN model results indicate no exceedance of the perceptibility or plume contrast either outside or inside of the Class I area boundaries.

At the request of KDHE and US Fish and Wildlife Services (FWS), Sunflower has completed a Class I Visibility Impact Analysis using the CALPUFF modeling system. This analysis was conducted in consultation with KDHE, EPA Region 7, and FWS.

Two different methods were used to evaluate background visibility, Method 2 (all values expressed in % light extinction), and Method 6 (all values expressed in deciviews). The Method 2 results did indicate visibility impacts exceeding 5%. Method 6 assesses data on a $98^{th}$ percentile basis, and predicted impacts to be below 0.5 deciviews.

CALPUFF is being used beyond the normally recommended maximum source receptor distance of 300 km, which can cause overestimation of visibility impacts. To address this problem, KDHE completed a Class I Visibility Impact Analysis using the CAMx modeling system, which does not have this distance limitation. The CAMx results indicated no visibility impacts exceeding 0.5 deciviews for any Class I area. This analysis is more representative than the CALPUFF analysis because of the large source receptor distance from Sunflower to surrounding Class I areas (> 400 km).

## 2. Impacts on Vegetation

In accordance with 40 CFR 52.21(o)(1), the owner shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the modification to the source. Sunflower Electric Power Corporation determined that the proposed facility and the associated increases of $NO_x$, $SO_2$, CO, $PM_{10}$, VOC /ozone, trace elements, and acid gases are not expected to have significant effects on vegetation.

Air pollutants can act together to cause injury to or decrease the functioning of plants. Concentrations of pollutants in studies referenced are substantially higher than those occurring as a result of this project. Consequently, no synergistic effects of the air pollutants are expected to inhibit vegetation at or near the Holcomb Generating Station.

## 3. Impacts on Soils

Both soil types endemic to this region are deep, noncalcareous, very sandy soils in steep, duny terrain. The oils are low in fertility and drain very easily. Water is absorbed quickly, and consequently, runoff is very low. Blowout of the soil is prevalent where vegetation is lacking. Erosion often is a problem.

Sulfates and nitrates caused by $SO_2$ and $NO_x$ deposition on soil can be beneficial and detrimental to soils depending on its composition. However, given the low emission levels and the sandy soils in the vicinity of the project, it should not significantly affect the soils in the vicinity of the project.

## 4. Growth in Commercial, Residential and Industrial Activity

This modification at the Holcomb facility will stimulate an increase in the local labor force during the construction phase in the Holcomb area, but the increase will not result in permanent/significant commercial and residential growth occurring in the vicinity of the Holcomb. During the construction phase of the project additional employees will be needed for various periods of time and in various capacities. However, no short term negative impacts are anticipated.

Operation of the facility will require additional employees over current staffing levels. Most of these positions would be recruited locally (within 50 miles of the facility). A portion of the new employees could choose to relocate with a subsequent increase in permanent residences to areas nearer the facility. These new residences are not anticipated to add appreciably to air emissions in the vicinity of the facility.

No new local industrial facilities related to the project are anticipated. An increase in commercial activity related to transportation of coal and lime to the facility and removal of by-products materials (bottom ash) would occur; however, any emissions increases would be from mobile sources and are not part of this analysis. Therefore, the project is not anticipated to have sustainable negative impacts to the area based on collateral growth.

## D. Public Involvement

Following its initial review of Sunflower Electric Power Corporation's application, the KDHE BAR made a preliminary determination that the application met the standards for issuance of a construction permit and prepared a draft permit for public review and comment.

The draft permit was available for public review from September 21, 2006 through December 15, 2006. The first public hearing was held in Garden City, Kansas on Tuesday, October 24, 2006. The second public hearing was held in Topeka, Kansas on Thursday, October 26, 2006. The third public hearing was held in Lawrence, Kansas on Thursday, November 16, 2006, and was continued on Friday, November 17, 2006. The hearings were conducted in order to obtain oral and written comments concerning the proposed permit. The record was held open for comment until December 15, 2006.

The total number of verbal comments submitted at public hearings was one hundred twenty-nine (129). In addition to the verbal comments received during the public hearings, there were four hundred fifty (450) written comments and one hundred ninety (190) e-mailed comments submitted to the Department during the public notice period. Comments were submitted by five (5) organizations, for a total of 645 written comments. The total number of oral and written comments submitted was seven hundred seventy-four (774).

Section IV of this document includes the KDHE response to public comments and Section V includes the KDHE response to comments from organizations.

# IV. RESPONSE TO PUBLIC COMMENTS

## A. Public Comments: Kansas Regulations are Less Stringent

***KDHE Response:***

*The Kansas air pollution control statutes and regulations are consistent with the federal program and have been approved by EPA as part of Kansas' State Implementation Plan (SIP). EPA's approval of Kansas' SIP means that it complies with the requirements of the Clean Air Act. Pursuant to that approval, Kansas is authorized to implement its own PSD program. There are currently 36 states that implement the PSD program in the same fashion. When issuing a PSD permit, KDHE follows its SIP-approved regulations, including the federal rules incorporated by reference, and any applicable state or federal guidance.*

## B. Public Comments: Emission Levels Established in the Permit are Too High

***KDHE Response:***

*During the air permitting process, KDHE determines the Best Available Control Technology (BACT) emission limitations for regulated pollutants. The BACT emissions limitations for a proposed source are determined on a case-by-case basis taking into consideration, among other things, the availability and achievability of a limitation. Sunflower prepared and submitted information and documentation for KDHE to consider in determining the appropriate BACT limitations for Holcomb 2 and 3. KDHE evaluated the information, and then conducted its own investigations. KDHE studied the latest proven technologies and compared this facility to similar facilities recently receiving permits and their emission limitations. KDHE then determined the appropriate limitations for the proposed source. In making its final BACT determination as reflected in the final permit, KDHE received guidance from EPA and considered information received during the public comment period. Tables 1 and 2 below compare the final permit limits for Holcomb 2 and 3 and the auxiliary boilers with the average of recently permitted power plants and national standards.*

***TABLE 1. AVERAGE EMISSIONS FROM COAL-FIRED STEAM GENERATORS***

| *Pollutant* | *National Averages (lb/mmBtu)* | *Recent PSD Permit Limits[1] (lb/mmBtu)* | *Holcomb Expansion Project Limits (lb/mmBtu)* |
|---|---|---|---|
| *Oxides of Nitrogen ($NO_x$)* | *0.46[2]* | *0.071* | *0.05* |
| *Sulfur Dioxide ($SO_2$)* | *0.60[3]* | *0.106* | *0.065/0.085[4]* |
| *Particulate Matter ($PM_{10}$)* | *0.03[3]* | *0.029* | *0.018* |
| *Volatile Organic Compounds (VOC)* | *N/A* | *0.004* | *0.0035* |

*[1] Based on 57 permits with applications submitted from 2004 to present.*
*[2] Emission limit from Phase II of Acid Rain program.*
*[3] Emission limits from 40 CFR Part 60 Subpart Da. $PM_{10}$ limit does not include the condensable portion of $PM_{10}$.*
*[4] Limit dependent upon sulfur content of coal fired (<> 0.9% Sulfur).*

| Pollutant | National Averages (lb/mmBtu) | Recent PSD Permit Limits[1] (lb/mmBtu) | Holcomb Expansion Project Limits (lb/mmBtu) |
|---|---|---|---|
| Carbon Monoxide (CO) | N/A | 0.145 | 0.15 |
| Mercury (Hg)[5]( lb/GWh) | 0.097[3] | 0.044 | 0.020 |

***TABLE 2. AVERAGE EMISSIONS FROM GAS-FIRED AUXILIARY BOILERS***

| Pollutant | National Averages[6] (lb/mmBtu) | Recent PSD Permit Limits[7] (lb/mmBtu) | Holcomb Expansion Project Limits (lb/mmBtu) |
|---|---|---|---|
| Oxides of Nitrogen ($NO_x$) | 0.20 | 0.109 | 0.036 |
| Sulfur Dioxide ($SO_2$) | 0.20 | N/A | 0.001 |
| Particulate Matter ($PM_{10}$) | 0.03 | N/A | 0.01 |
| Volatile Organic Compounds (VOC) | N/A | 0.010 | 0.005 |
| Carbon Monoxide (CO) | N/A | 0.107 | 0.08 |

## C. Public Comments: In General, Pollution Levels are Too High

***KDHE Response:***

*A critical element of the air permitting process and the Kansas' State Implementation Plan (SIP) of the federal clean air laws and regulations, in general, is protection of the ambient air quality. The EPA has established primary and secondary national ambient air quality standards (NAAQS) for six criteria pollutants, which include ozone, particulate matter (PM), sulfur dioxide ($SO_2$), oxides of nitrogen ($NO_x$), carbon monoxide (CO), and lead. The primary standards protect human health and the secondary standards protect public welfare. In setting the standards, EPA considers sensitive populations (e.g., asthmatics, children, elderly) and the type of effect (chronic versus acute). EPA periodically receives new health-based scientific studies, and using the standard administrative rulemaking process, revises appropriately those NAAQS standards. The ambient air quality in Kansas meets all the current NAAQS, which is why the PSD permitting process is applicable to Holcomb 2 and 3. As part of its application, Sunflower provided information demonstrating that air emissions from Holcomb 2 and 3 would not cause or contribute to an exceedance of any NAAQS.*

[5] *Assumes GWh/10,000 mmBtu and 100 GWh/TBtu (~34% efficient).*
[6] *Emission limits from 40 CFR Part 60 Subpart Da.*
[7] *Emission limits from EPA's RACT/BACT/LAER Clearinghouse.*

## D. Public Comments: Mercury Emissions are Too High

***KDHE Response:***

*The emission limit established in the final permit is 0.020 lb/GWh, an 80 percent reduction below the EPA's NSPS limit of 0.097 lb/GWh. Sunflower stated during the public hearing that mercury controls will be added to the existing unit so that the combined mercury emissions from the existing plant and two new plants will not increase from current levels.*

## E. Public Comments: There Should be More Energy Efficiency

***KDHE Response:***

*There are no provisions to regulate customer utilization of electric energy (energy efficiency) in PSD permits. These comments were referred to Secretary Bremby for further policy considerations.*

## F. Public Comments: There Should be More Utilization of Renewable Energy

***KDHE Response:***

*There are no provisions to regulate selection of generation technology (including renewable energy) deployed by electric utilities in PSD permits. These comments were referred to Secretary Bremby for further policy considerations.*

## G. Public Comments: Carbon Dioxide Issues Should be Addressed

***KDHE Response:***

*There are no provisions to regulate carbon dioxide in PSD permits. These comments were referred to Secretary Bremby for further policy considerations.*

## H. Public Comments: Water Consumption and Conservation Should be Addressed

***KDHE Response:***

*KDHE does not have regulatory authority over matters related to the use of water for generating facilities. The Kansas Department of Agriculture (KDA), Division of Water*

*Resources (DWR) is responsible for regulating the use of water in Kansas. All public comments related to water consumption and conservation have been forwarded to the Chief Engineer, DWR, KDA.*

*According to the DWR, Kansas Water Appropriations Act Regulations, K.A.R. 5-5-3 and 5-5-9 state that the consumptive use of water shall not be increased after a water right has been determined. Based on these regulations, the conversion of water use from irrigation to industrial use will result in an approximate 40% reduction from the prior authorized quantity. The Chief Engineer also has authority under K.S.A. 82a-733 to require Sunflower to adopt and implement state approved industrial water conservation plans and practices to assure public benefit and promote public interest.*

# V. RESPONSE TO COMMENTS FROM ORGANIZATIONS

## A. EPA REGION 7 COMMENTS

### $SO_2$ Best Achievable Control Technology (BACT)

**Comment 1:**

The $SO_2$ baseline selected by Sunflower Holcomb to evaluate BACT appears not to be representative of the Powder River Basin (PRB) coals historically used in Region 7, including Holcomb Unit 1, and should be reevaluated.

***KDHE Response:***

*The draft permit contained a single $SO_2$ limit of 0.095 on a 30 day rolling average basis. KDHE has modified the final permit to require a tiered 30 day rolling average $SO_2$ emission limit based on sulfur content of the coal being burned. The limit is 0.085 lb/mmBtu if the $SO_2$ is greater than or equal to 0.9 lb/mmBtu as detected at the input to the scrubber and the limit is 0.065 lb/mmBtu if the $SO_2$ is less then 0.9 lb/mmBtu at the inlet to the scrubber.*

*The tiered $SO_2$ removal requirement in the final permit addresses the objective of maintaining a high level of control efficiency in the flue gas desulfurization (FGD) system for various levels of inlet $SO_2$. Imposition of restrictions on fuel choice has not previously been part of BACT determination and is not justified.*

### Particulate Matter (PM) Monitoring

**Comment 2:**

In 2004, EPA promulgated final performance specifications, PS-11, for installation, operation, maintenance, and quality assurance of continuous particulate matter emission monitoring systems (PM-CEMS). The proposed Sunflower Holcomb units are capable of installing this equipment and pushing the knowledge base forward.

***KDHE Response:***

*The final permit requires other forms of monitoring, rather than a PM CEMS. The final permit requires a bag leak detection system equipped with an alarm system and continuous recording device, along with a continuous opacity monitor (COMS), to monitor the particulate matter control device (fabric filter) and inform the operator almost immediately of any operational problems with said device. The bag leak detection system in conjunction with COMS is an adequate verification of ongoing compliance in lieu of a PM CEMS.*

**Carbon Monoxide (CO)**

**Comment 3:**

EPA recommends replacing the one time initial stack test under "Compliance and Other Performance Testing" Condition 1 with a requirement for Sunflower to install, calibrate, maintain, and quality assure CO-CEMS on each of the three new units. As part of this reconsideration, KDHE should determine whether it would be more appropriate to retain the short term averaging period and current proposed BACT limit or lengthen the averaging period (e.g. 30 day rolling) and lower the BACT limit since any variability in short term transient spikes would be flattened over time.

***KDHE Response:***

*The final permit has been revised to require a CO CEMS and an emission limit of 0.15 lb/mmBtu. The 30 day rolling average is consistent with recently permitted similar facilities. This emission limit of 0.15 lb/mmBtu shall include periods of startup, shutdown, and malfunction.*

**Continuous Emissions Monitoring System (CEMS)**

**Comment 4:**

The permit requires installation of $NO_x$ and $SO_2$ CEMS consistent with NSPS Subpart Da, but is silent on the use of the CEMS data for verification of BACT limits in the permit. EPA requests an explicit statement in the permit that Sunflower will install, operate, maintain, and quality assure such CEMS to verify direct compliance with the BACT limits.

***KDHE Response:***

*Language has been added to the permit requiring the CEMS to verify direct compliance with the BACT limits.*

**Boiler Operating Day**

**Comment 5:**

The draft permit, under "Air Emission Limitations" Condition 2, 2$^{nd}$ paragraph, notes that "day" [as in boiler operating day] shall have the same meaning as in NSPS Subpart Da. The PSD permit limits should explicitly state the definition of "day", and should not rely on referencing the NSPS, which may be subject to change.

***KDHE Response:***

*It is appropriate to follow the definition of "boiler operating day" in NSPS Subpart Da. If a court mandated change to NSPS occurred, two different definitions could exist, one for NSPS* *and one for the PSD permit. There is no environmental benefit from the requirement to monitor, track, and report boiler operating day and emission limit compliance in two different ways. Therefore, no change has been made to this portion of the permit language.*

**BACT Modification and Public Participation**

**Comment 6:**

"Compliance and Other Performance Testing" Condition 8 describes a process that allows Sunflower to petition KDHE for a new $PM_{10}$ limit if unable to achieve the 0.018 lb/mmBtu BACT limitation after the initial compliance demonstration and subsequent evaluation period. Any change in the $PM_{10}$ limit should undergo an opportunity for public and EPA peer review.

***KDHE Response:***

*KDHE has clarified the final permit to include an opportunity for public and EPA peer review for changes in the $PM_{10}$ limit in accordance with KDHE regulations.*

**18 Month Construction Timeline**

**Comment 7:**

"General Provisions", Condition 2, requires Sunflower to submit information for reevaluation of the BACT and modeling analyses for any unit that does not commence construction within the initial 18 months of permit issuance. Where multiple units are involved, there can sometimes be confusion about the severability of this requirement, so it is imperative to make clear that unless all three units commence construction, as defined in the PSD rules, within the initial 18 month period those units that do not must undergo reanalysis. KDHE's proposed permit language appears to carry out this concept, but could benefit from additional clarity.

***KDHE Response:***

*The General Provisions Item 1 and 2 have been revised in the final permit and are more explicit in defining actions to be followed should deadlines of 40 CFR 52.21(r) lapse.*

**$SO_2$ Short Term Limit**

**Comment 8:**

The revised AERMOD modeling analysis, submitted in September, 2006, notes that it may be appropriate to establish a short term 3-hour limit for $SO_2$. This limit would assure the modeling assumptions remain valid if Sunflower chooses to combust coal with sulfur content greater than 0.5%. Since the permit does not restrict fuel flexibility, the recommended limit, 4,358 lb/hr, 3-hour average, should be included as a condition of the permit.

***KDHE Response:***

*The final permit contains a short term $SO_2$ limit. This limit is 1483 lb/hour averaged over a 24 hour calendar day, including startup and shutdown. This limit protects the environment from short term emissions during maintenance activity and protects Air Quality Related Values, National Ambient Air Quality Standards, and PSD increment.*

## B. NATIONAL SIERRA CLUB COMMENTS

**Additional Planned Facilities (Sierra Club Comment [SCC I])**

**Comment 9:**

The draft PSD permit fails to include all emission sources planned at the Holcomb Station. Sunflower announced that it intends to "integrate" additional emissions sources with its power plant. However, it does not appear that any of the emissions from these support facilities are included in the PSD analysis for the plant. The KDHE must include emissions from these planned emission sources before issuing a permit for the new units.

***KDHE Response:***

*An application has recently been received for an ethanol plant permit as one component of the Sunflower Integrated Bioenergy Center (SIBC). The power plant will not be providing any support services to the ethanol plant. Therefore, the ethanol plant is a separate source for permitting purposes. Based on that decision, Sunflower was required to conduct additional dispersion modeling to include the ethanol plant facility land leased by SIBC as ambient air. The modeling did not show any NAAQS or PSD increment impacts.*

*If/when any other facilities submit permit applications which are part of the proposed SIBC operation, KDHE will evaluate in relation to previously permitted sources and the agency will address such a situation at that time.*

**Carbon Dioxide ($CO_2$) and Mercury (SCC II A and B)**

**Comment 10:**

KDHE must deny the permit because the proposed plant will emit greenhouse gases and mercury at rates that do not protect the health of persons or the environment because they present a substantial endangerment to peoples' health and the environment.

- **Carbon Dioxide -** The proposed 2100 MW of coal-fired generation at the Holcomb Station will release huge quantities of carbon dioxide ($CO_2$), a potent greenhouse gas. It is expected that 14,000,000 tons of $CO_2$ will be released each year from the proposed units.

- **Mercury -** The Holcomb units 2-4 will also emit mercury at a rate up to 0.097 lb/GWh, excluding startup, shutdown and malfunction. At this rate, the three new units will emit 1,784 pounds of mercury into the local environment every year.

***KDHE Response:***

*With respect to $CO_2$, see Response to Section IV, Comment G.*

*There are now 2 units proposed for a total of 1400 MW, with $CO_2$ production of approximately 11 million tons/yr.*

*With respect to mercury, see also Response to Section IV, Comment D.*

*Holcomb 2-3 mercury emissions are limited to 0.020 lb/ GWh, a far more restrictive limit than required by Federal regulations (0.097 lb/ GWh). This emission rate would have a potential-to-emit of 232 lb/year (in lieu of 1784 lb/hr).*

**BACT, PM $_{2.5}$ (SCC III A)**

**Comment 11:**

The Draft Permit does not include a BACT limit for $PM_{2.5}$ emissions from Holcomb 2-4. Nor does it appear that KDHE even considered such a limit. This is unlawful and must be corrected before a PSD permit can be issued.

***KDHE Response:***

*On April 5, 2005, EPA issued guidance in the form of a memorandum to address how States should implement major New Source Review (NSR) for $PM_{2.5}$ until the $PM_{2.5}$ implementation is promulgated. EPA says in the April 5, 2005 memo that,*

> *"Because we have not promulgated the $PM_{2.5}$ implementation rule, administration of a $PM_{2.5}$ PSD program remains impractical. Accordingly, States should continue to follow the October 23, 1997 guidance for PSD requirements."*

*The October 23, 1997, guidance states:*

> *"EPA believes that sources should continue to meet PSD and NSR program requirements for controlling $PM_{10}$ emissions (and, in the case of $PM_{10}$ nonattainment areas, offsetting emissions) and for analyzing impacts on $PM_{10}$ air quality. Meeting these measures in the interim will serve as a surrogate approach for reducing $PM_{2.5}$ emissions and protecting air quality."*

*The final Holcomb permit includes BACT emission limits for $PM_{10}$ and thus establishes BACT for $PM_{2.5}$ using $PM_{10}$ as a surrogate in accordance with the above guidance. Thus, a BACT limit for $PM_{2.5}$ is not required at this time.*

**BACT, Production Processes and Fuels (SCC III B)**

**Comment 12:**

The BACT determinations for the coal-fired boilers did not include a sufficient analysis of cleaner production processes and innovative fuel combustion techniques. A BACT analysis for a coal fired power plant must include consideration of cleaner production processes and innovative fuel combustion techniques. 42 U.S.C. § 7479(3); 40 C.F.R. § 52.21(b)(12). Natural-gas fired generators, circulating fluidized bed (CFB), and integrated gasification combined cycle (IGCC) are all an inherently cleaner production process for the generation of electricity from coal that prevents the emissions of regulated pollutants into the atmosphere by removing contaminants such as sulfur and mercury from the hydrocarbons in the coal before the hydrocarbons are burned.

***KDHE Response:***

*The facility did an analysis as part of determining the best coal technology to utilize. The "Coal Technology Selection Study" by Black and Veatch Corporation concluded:*

> *"The economic analysis, as provided in Table 3 below (Table 1-3 from Technology Selection Study by Black and Veatch) indicates the lowest cost technologies are the conventional PC and CFB units. The IGCC levelized busbar cost is roughly 50 percent higher than those of the PC and CFB."*

***TABLE 3. BUSBAR RESULTS (FROM TABLE 1-3 OF TECHNOLOGY SELECTION STUDY BY BLACK AND VEATCH)***

| *Case* | *Description* | *30-Year Levelized Busbar Cost, ¢/kWh* | *30-Year Levelized Annual Cost, $1,000,000* |
|---|---|---|---|
| *1* | *Supercritical PC Subcritical* | *4.64* | *256.2* |
| *2* | *PC* | *4.60* | *254.0* |
| *3* | *CFB* | *4.182* | *265.8* |
| *4* | *IGCC* | *6.91* | *381.3* |
| *Results are based on economic criteria from Table 5-1, fuel forecasts from Table 5-2, and the inputs from Table 5-3.* | | | |

*To date, only two commercial nonsubsidized IGCC plants with a primary application of power generation have been built: the Delaware City Refinery, which utilizes petcoke, and the Negishi Refinery in Japan, which utilizes heavy oil. Both of these plants achieved commercial operation after 2000, are located in refineries, and utilize byproducts of the refining process as their fuel source. Currently, no IGCC plant is operating on PRB coal, the fuel source selected for use at the Holcomb site, although the Dow Plaquemine demonstration project operated on PRB coal from 1987 until 1995. To date, the largest IGCC power plant built is the 550 MW Sarlux plant that operates on oil. The Lima petcoke-based IGCC plant is in the early stages of construction and is expected to be about 600 MW in size. Construction of an IGCC plant in the immediate future, as would be the case for the Holcomb units, would entail a substantially greater degree of uncertainty about construction cost and operating reliability compared to a PC fired plant.*

*While IGCC technology remains promising and has been targeted for development in several locations, at this point, IGCC could not meet the required in-service dates needed by the Holcomb participants. In the 2013 time frame, significantly more data will be available regarding the cost and performance of second generation oxygen-blown entrained flow based technology (COP, GE, and Shell) as well as from demonstration projects of less proven gasification technologies (Siemens, MHI, and TRIG).*

*The other two technologies evaluated, PC (either super or subcritical) and CFB, are commercially available for consideration for a new 700 MW coal-fired generating facility at Holcomb. The emissions of regulated pollutants from these two technologies are very similar. The most fuel efficient technology is supercritical PC, which is at least 3 percent more efficient than CFB technology. CFB is expected to be slightly more expensive, as measured by the levelized busbar cost of power, than PC.*

*Within the accuracy of the evaluation, the subcritical and supercritical PCs are assumed to be equivalent. Supercritical PC is the preferred technology (rather than subcritical PC) for the two 700 MW net units to be located at the existing Holcomb station site because it is more efficient, which reduces the coal consumption by approximately 215 tons per day (tpd) per unit. This yields more than 2 percent fewer total emissions because of the reduced fuel burn rate.*

*Sunflower selected a supercritical pulverized coal fired boiler and steam turbine/generator as the power generating technology for Holcomb. Sunflower did consider alternative power generating technologies in making this decision. Sunflower discussed the choice of generation technology in Part 1 Section 1.1 of the Permit Application, pages 1-1 through 1-3, including CFB boilers, IGCC, and natural gas. Sunflower concluded that these alternative generating technologies were inappropriate for the Holcomb Station Expansion Project considering environmental performance, general cost and technical performance characteristics of these technologies, and site-specific conditions at Holcomb. Having made this determination, Sunflower then carried out the required 5-step BACT analysis on the chosen technology, as described in the Permit Application.*

*Sunflower subsequently submitted a study by Black and Veatch of alternative generating technologies, including CFB boilers and IGCC power plants (August 24, 2006). The discussion of alternative technologies in that document supports the original Sunflower analysis in this regard. In short, these other technologies are more expensive to construct and maintain, have lower reliability, and are not demonstrably proven effective technologies at the scale required for Holcomb.*

*KDHE has not been able to document any recent technical development that would suggest that these generation technologies have been installed and demonstrated recently such that Sunflower's conclusions would change. The Holcomb BACT analysis therefore appropriately takes as its starting point the power generating technology selected by Sunflower, after due consideration of alternative methods of power generation.*

*The process employed by Sunflower is consistent with that employed in other recent PSD permit applications. For example, the PSD permit for the proposed Desert Rock facility included an* *attachment which examined alternative generation technologies and supported the selection of pulverized coal fired power generation. The issuing agency, EPA Region IX, requested Sithe to provide information on the technical feasibility of IGCC using the proposed fuel source but did not include IGCC in the BACT analysis on the basis that to do so would be redefining the source. Emission controls were then considered for the selected generating technology, as noted in the Desert Rock Ambient Air Quality Impact Report (p. 8):*

> *"In accordance with the top-down BACT process, Sithe's PSD application first identified all of the potentially available control technologies for pulverized coal fired boilers, eliminated technically infeasible options, and then ranked the remaining control technologies, beginning with the technologies that will result in the most stringent control and the lowest emissions."*

*Furthermore, in a guidance letter dated December 13, 2005 (Page Letter), Stephen D. Page, EPA Director of Air Quality Planning, Standards, stated that a BACT analysis for a proposed supercritical pulverized coal power facility need not include an evaluation of IGCC technology. A subsequent action for judicial review brought by the Sierra Club and other environmental organizations in which the plaintiffs sought to require EPA to withdraw the Page Letter was settled by an agreement under which EPA merely acknowledged that its opinion on this issue as stated in the Page Letter constitutes non-binding guidance but did not retract its view of the law. No court decision addresses this issue. Accordingly, KDHE adhered to its position regarding this issue, consistent with that of EPA.*

**BACT, Production Processes and Fuels (SCC III C)**

**Comment 13:**

The BACT determination did not consider fuel mixing as a control option. The Clean Air Act requires that BACT limits be established based on emission limits which may be established using cleaner fuels as required by 52.21(b)(12). Unless site-specific energy, environmental, or economic impacts justify the rejection of cleaner fuels, the BACT limits for Holcomb Units 2-4 must take into account the lowest emission rate achievable with clean fuels. KDHE did not consider clean fuels when setting limits in the Draft Permit.

***KDHE Response:***

*There is no reference to this clean fuels requirement in 52.21(b)(12). The facility has also demonstrated that natural gas is economically infeasible (see Table 4 Comment 14 response).*

**BACT, Production Processes and Fuels (SCC III C a)**

**Comment 14:**

A BACT determination must be set based on the lower emissions achievable by mixing natural gas with coal. In addition to burning PRB coal, the proposed boilers for Holcomb 2-4 are also designed to burn natural gas. *See e.g.*, Form 6-1.0 (Indirect Heating Unit Form for Holcomb Units 2, 3, and 4, listing natural gas as a secondary fuel for the boilers). A BACT analysis must also consider mixing natural gas with coal in the Holcomb 2-4 boilers. Since the boilers are designed to be able to fire natural gas, alone or in combination with coal, there is no argument that burning gas would "redefine the source."

***KDHE Response:***

*The primary purpose for burning coal alone is cost effectiveness and fuel supply availability. If electricity generated from a natural gas fuel supply was a viable cost alternative, the design would be for a combined cycle gas turbine design, which is much more efficient than a pulverized coal boiler for burning natural gas. Combining these two fuel supplies into one combustion technology is not practical from a design and efficiency perspective.*

*The Holcomb steam generators will be designed to allow the use of natural gas for start-up fuel only. The steam generators will not be able to attain a substantial portion of the design output using natural gas. To do so would require a fundamental re-design of the units. The statement* "Since the boilers are designed to be able to fire natural gas, alone or in combination with coal" *is true only to the extent that natural gas is burned alone for startup, but that will only get the unit on line, after which time coal must be introduced for meeting unit load commitments. As stated above, these are large base load units designed specifically to burn coal, and KDHE is unaware of any recent units of this size designed to co-fire natural gas with coal for base load operations.*

*At KDHE's request, Sunflower provided a simplified calculation of the cost-effectiveness of combustion of natural gas as a means of reducing $SO_2$ as an example of a pollutant for which emissions would be reduced to near zero if natural gas were burned instead of coal. This calculation, shown in Table 4, indicates that the cost of reducing emissions through use of natural gas, whether in whole or, in part, is unreasonably high.*

***TABLE 4. COST EFFECTIVENESS OF REDUCING $SO_2$ THROUGH THE USE OF NATURAL GAS***

| | ***Units of measure*** | ***Coal*** | ***Natural Gas*** | ***Difference*** |
|---|---|---|---|---|
| *$SO_2$ emissions* | *lb-$SO_2$/mmBtu* | *0.085* | *0* | *-0.085* |
| *Delivered cost* | *$/mmBtu* | *$1.25* | *$6.95* | *$5.70* |
| *$SO_2$ reduction cost* | *$/lb-$SO_2$* | | | *$67* |
| *$SO_2$ reduction cost* | *$/ton-$SO_2$* | | | *$134,118* |

*Notes:*
*Coal price based on recent delivered cost of coal to Holcomb.*
*Natural gas price based on NYMEX settlement price at Henry Hub for the calendar year 2012 as of January 18, 2007.*

**BACT, Production Processes and Fuels (SCC III C b)**

**Comment 15:**

The BACT limits must account for typical low sulfur western subbituminous coal, rather than worst case coal. The historic coal records for Holcomb 1 and the large volume of data collected by USEPA for western subbituminous coal-fired units show that $SO_2$ content of approximately 0.6 to 0.8 lb $SO_2$/mmBtu is typical of PRB coal. The Clean Air Act requires consideration of the cleanest versions of fuel, not worst-possible versions of PRB coal, when setting BACT. 42 U.S.C. § 7479(3). Therefore, BACT must be established assuming typical 0.6 to 0.8 lb/mmBtu coal, rather than the worst-possible- 1.23 lb/mmBtu - coal that was assumed in the Developer's application. By establishing BACT as 92% control efficiency from an FGD and typical western subbituminous coal (conservatively assuming that all sulfur is converted to $SO_2$) the permit limit should be 0.048 to 0.064 lb/mmBtu, rather than the 0.095 lb/mmBtu limit in the Draft Permit.

***KDHE Response:***

*Sunflower proposed to use western low sulfur coal, both subbituminous coal (mostly from the Powder River Basin) as well as low-sulfur western bituminous coal. The sulfur content of the coals in question is not uniform. The permit establishes a tiered emission limit for $SO_2$ that will provide for lower emission limits with lower sulfur coal. Please refer to Comment 1.*

*Unlike control equipment investments, fuel selection cannot be made for the life of the power plant as a practical matter. The availability of such restricted fuels and the cost associated with them is very difficult to determine as the cost exposure is effectively unlimited. This comment seeks to further restrict the range of coal that might be used at Holcomb. Such restrictions have not been included in any other similar permits.*

*KDHE asked Sunflower to provide as an illustration the following example which shows how relatively modest variations in fuel cost could result in very high emission control costs. Table 5. assumes that coal within the upper tier of proposed emission limits (Coal A) and that being required to use the lowest sulfur western coal available (Coal B) would result in operating within the lower tier of the proposal for purposes of illustrating the point. It is also assumed that the lower sulfur coal would be available at a premium price, as is confirmed by recent coal prices.*

***TABLE 5. COST PER TON OF $SO_2$ REMOVED BASED ON DELIVERED COST OF COAL***

| | *Units of Measure* | *Coal A* | *Coal B* | *Difference* |
|---|---|---|---|---|
| *$SO_2$ emissions* | *lb-$SO_2$/mmBtu* | *0.085* | *0.065* | *-0.02* |
| *Delivered cost* | *\$/mmBtu* | *\$1.25* | *\$1.40* | *0.15* |
| *$SO_2$ reduction cost* | *\$/lb-$SO_2$* | | | *\$7* |
| *$SO_2$ reduction cost* | *\$/ton-$SO_2$* | | | *\$15,000* |
| *Notes:Coal price based on recent delivered cost of coal to Holcomb.* | | | | |

*As Table 5 indicates, a variation in the delivered cost of coal of $0.15/mmBtu could result in a cost per ton of $SO_2$ removed of $15,000.*

**$SO_2$ BACT and Emission Limits (SCC III B a)**

**Comment 16:**

The BACT Determination For $SO_2$ Is Inadequate since it omitted sorbent injection. Neither the applicant nor KDHE identified lime/sorbent injection in addition to scrubbing as an available control option in step one of the top-down process. The BACT analysis for $SO_2$ must be redone to consider this option.

***KDHE Response:***

*Dry slaked lime injection is a subset of sorbent injection that was rejected in the screening because it has less $SO_2$ removal efficiency (~20 to 40%) than the selected control technology (LSD FGD at 92-95%) (See Holcomb PSD Permit Application, Appendix E, Table E-1 "Review of Potential Control Technology," page 3 of 7).*

*This comment asserts that adding sorbent injection in the boiler (or in the ducting prior to the fabric filter when the baghouse precedes the scrubber) can be applied in series with the selected post-combustion FGD technology in order to improve overall removal efficiency. That is, by lowering the $SO_2$ into the LSD with sorbent injection and assuming the same $SO_2$ removal efficiency in the LSD, lower outlet $SO_2$ emissions are obtained.*

*LSD technology vendors, though, typically guarantee $SO_2$ removal efficiency with an "outlet stopper" emission rate. The "outlet stopper" is the lowest emission rate (lb/mmBtu) guaranteed, regardless of the inlet loading. This form of commercial guarantee has been documented in the technical literature. Therefore, from a commercial perspective, lowering the inlet would not necessarily result in a lower guaranteed $SO_2$ emission rate.*

*Since the fabric filter does not precede the LSD, duct sorbent injection as suggested by this comment is not a viable option for Holcomb. In essence, LSD technology is a highly efficient form of sorbent injection upstream of a fabric filter where residence time, approach to saturation temperature and reagent injection ratios are optimized for $SO_2$ control.*

*The second option suggested by this comment (furnace sorbent injection or FSI) is a technology that has limited commercial experience. KDHE is aware of an FSI installation on a 72 MW pulverized coal-fired unit, with planned FSI installations on three 75 MW pulverized coal boilers (from the 4$^{th}$ quarter 2006 through 2008). The potential for increased furnace slagging and reduction in heat transfer capability, the lack of commercial experience at the unit size for the new Holcomb units, and the relatively low $SO_2$ removal efficiency of FSI do not justify further consideration of this technology for $SO_2$ control at the Holcomb generating units.*

*Additionally, duct sorbent injection technology has very little commercial experience in the US, and that mostly on small units. KDHE is not aware of any large utility unit burning PRB coal* *with this system. KDHE has been unable to document a single sorbent injection system anywhere in the U.S. that was installed for the purpose of $SO_2$ control. KDHE is aware of units installed for the purpose of $SO_3$ control. The most notable example is the AEP Gavin units. These units had a problem with $SO_3$ plumes following installation of SCRs and the sorbent injection was added to address the newly-created $SO_3$ emissions associated with the SCR.*

*This comment asserts that the selected $SO_2$ control technology for Desert Rock includes sorbent injection. While it is correct that the table at page 30 of Sierra Ex. K indicates the choice of a combined sorbent injection- wet FGD system for $SO_2$ control, the description of $SO_2$ control options does not mention sorbent injection. The sulfuric acid BACT discussion does specifically address the use of sorbent injection to lower sulfuric acid emissions. Thus, Desert Rock's plan for sorbent injection is not for $SO_2$ control. Rather, a wet scrubber and very tight sulfuric acid emission limits, the contingency plan for retrofitting the sorbent injection system is for the purpose of $SO_3$ and sulfuric acid control.*

**$SO_2$ BACT and Emission Limits (SCC III B b)**

**Comment 17:**

The BACT Analysis failed to consider a circulating dry scrubber. Despite the fact that circulating dry scrubbers are available and achieve greater $SO_2$ control than the spray dryer technology proposed for Holcomb units 2-4, it does not appear that circulating dry scrubbers were considered in the top-down BACT analysis. KDHE must correct the omission of circulating dry scrubbers from the top-down $SO_2$ BACT analysis. Doing so will result in a BACT limit for $SO_2$ based on the control achievable with a circulating dry scrubber (CDS) (if not an even more efficient scrubber).

***KDHE Response:***

*No system at a scale comparable to Holcomb has been built. In addition, the operating experience with this technology is the U.S. is not sufficient to establish it as being commercially available, and the apparent percentage removal attainable with the CDS is most probably in the same range as that attainable with a LSD-FGD system. Therefore, it was not necessary or appropriate to consider this technology in a BACT evaluation for Holcomb.*

**$SO_2$ BACT and Emission Limits (SCC III B c)**

**Comment 18:**

The Developers incorrectly rejected a wet scrubber as the top-ranked pollution control options for $SO_2$ at Holcomb and KDHE set an inadequate BACT Limit as a result. This attempt conflicts with the Clean Air Act. BACT must be established based on the superior control achievable with a wet scrubber.

***KDHE Response:***

*This comment asserts that wet FGD is the "top ranked" pollution control option and bases its comments on the mistaken assumption that the percent $SO_2$ reductions achievable on high sulfur applications are also achievable when applied to low sulfur coal. As noted in the Holcomb application (see page 4-34), wet FGD has in the past been typically applied primarily at high sulfur coal projects. Although there are a few applications of wet FGD to low sulfur coal, these do not achieve the same percent reduction as high sulfur coal applications*

*Sunflower is proposing to use western low sulfur coal, both subbituminous coal (mostly from the Powder River Basin) as well as low-sulfur western bituminous coal. The sulfur content of the coals in question is not uniform. The permit has a tiered emission limit for $SO_2$ that will provide for lower emission limits with lower sulfur coal and maximize the $SO_2$ reductions across the range of fuel proposed for Holcomb 2-3. Please refer to the KDHE Response to Comment 1 for further information.*

*Based on the level of control achievable for low sulfur coals and other factors, LSD-FGD is the best overall control technology for application at Holcomb 2-3. Application of LSD-FGD to meet the proposed tiered $SO_2$ limits will result in Holcomb 2-3 achieving some of the lowest $SO_2$ emission rates in the country. KDHE response to comments 19 through 28 provides specific information to address the details of the Sierra Club comments and support the selection of LSD-FGD as the control technology for Holcomb 2-3 and setting BACT emission limits of 0.085 and 0.065 lb/mmBtu, dependent on the sulfur content of the fuel.*

**Comment 19:**

It is generally recognized that a wet scrubber is capable of greater $SO_2$ reductions than a dry scrubber. The proposed $SO_2$ BACT limit for the Desert Rock plant is substantially (37%) lower than the limit proposed in the Draft Permit for Holcomb 2-4. It must be assumed that BACT for Holcomb 2-4 is at least as low as the proposed Desert Rock permit BACT limits.

***KDHE Response:***

*This comment declares that $SO_2$ removal efficiencies for wet FGD "have been demonstrated above 98 percent," without any details concerning the application such as size of plant, fuel supply, or fuel sulfur content. It is well known that $SO_2$ removal efficiencies for wet FGD systems are generally higher for high sulfur coal applications than for low sulfur coal applications, for the fundamental physical reason that the chemical reactions that remove $SO_2$ are faster if the $SO_2$ concentration is higher. These uncorroborated claims of $SO_2$ removal efficiencies for wet FGD distort the potential $SO_2$ removal efficiency of wet FGD systems applied at PRB coal-fired generating units.*

*The great majority of new PRB coal-fired generating units include dry FGD for $SO_2$ control. However, there are some recent projects which propose the use of low sulfur coal with wet FGD. These projects, with estimates of their inferred $SO_2$ removal efficiency, are listed in the following table:*

*TABLE 6. $SO_2$ CONTROL EFFICIENCIES FROM PROPOSED COAL-FIRED GENERATING UNITS USING WET FGD AND LOW SULFUR COAL*

| *Project* | *Permit Status* | *$SO_2$ BACT Emission Rate (lb/mmBtu)* | *Estimated $SO_2$ Removal Efficiency (%)* |
|---|---|---|---|
| *Intermountain Power Project (IPP)* | *Final (appealed)* | *0.09 (30-day ave.)* | *93* |
| *Spruce Unit 2* | *Final* | *0.10 (30-day ave.)*<br><br>*0.06 (12-mo. ave.)* | *92 (30-day)* |
| *Iatan Unit 2* | *Final* | *0.09 (30-day)* | *93.6* |
| *Big Cajun II Unit 4* | *Final* | *0.10 (30-day)* | *89* |
| *Desert Rock* | *Draft* | *0.06 (24-hour)* | *96.3* |
| *Hugo 2* | *Final* | *0.065 (30-day)* | *96.2* |

*Two of the projects listed in Table 6, IPP and Spruce 2, are proposing wet FGD at power stations, both of which have existing units that utilize wet FGD systems. The applicant's direct operating experience with wet FGD on low sulfur coal support its proposed emission limits and expected performance of the new FGD systems. Big Cajun II, Unit 4 is currently permitted[8] to install either wet or dry FGD, with the same permit limit of 0.10 lb/mmBtu.*

*Based on the above, it is evident that although wet FGD may achieve higher $SO_2$ reduction, it is only slightly better. In practice, the difference is small; and it is possible to find some dry FGD that will do better than some wet FGD. That is, there is overlap in the performance capabilities. The final permit contains a two tiered $SO_2$ limit, tied to inlet $SO_2$ concentrations to ensure that the LSD-FGD performs at maximum capability across the range of fuel to be used. Sunflower has addressed separately why sorbent injection is not feasible at Holcomb 2-3.*

*The commenter refers to the recent EPA Region IX proposed permit for Desert Rock and quotes from the Ambient Air Quality Impact Report (AAQIR) as the basis for claiming that BACT for Holcomb 2-3 is* "superior control of a wet scrubber."

*With respect to the AAQIR report, EPA states that a comparative ranking of available $SO_2$ control technologies must take into consideration multiple variables, including coal sulfur content, control efficiency, and the resulting emission rate (lb/mmBtu), in addition to collateral impacts on other pollutants, energy impacts, and other environmental impacts. The following are the key points from the AAQIR regarding the $SO_2$ BACT determination:*

- *For a wet FGD, the control efficiency range is 90-98%, depending on coal sulfur content and it is lower with western coal.*
- *EPA acknowledges the use of western fuel itself is part of the $SO_2$ control strategy, stating, "Any discussion of the relative effectiveness of add on $SO_2$ control must also*

*[8] It is our understanding Big Cajun II is currently seeking revision of the permit to install a wet FGD as the only option in support of a planned change to the fuel supply which calls for using Illinois bituminous coal (high sulfur) as well as PRB; hence the change in technology.*

*take into account the level of uncontrolled $SO_2$ to be handled, which is highly dependent on the sulfur content of the coal to be burned. Higher removal efficiencies tend to be more practical when there is a high concentration of $SO_2$ in the flue gas, and vice versa."*

- *EPA relies on information provided by the applicant regarding control efficiency and accepts the stated project efficiencies for LSD-FGD (70-92%).*
- *EPA states that it reviewed the DOE/NETL (National Energy Technology Laboratory) database, EPA's RACT/BACT/LAER Clearinghouse, EPA's National Coal BACT Workgroup database, and the EPA spreadsheet of recently permitted and proposed coal-fired power plants and the National Coal Work Group database. On this basis EPA concludes that Desert Rock's proposed limit is BACT because it "is below the lowest $SO_2$ BACT emission limit for recently permitted facilities."*

*EPA does not indicate what control efficiency is expected of the wet scrubber selected for Desert Rock, and does not question the potential for the LSD-FGD control efficiency to be higher than that stated by Desert Rock. Sierra Club Exhibit S6 would indicate that, contrary to the above, the expected control efficiency range for LSD-FGD is 92-95%, depending on fuel sulfur content. It should be noted that the Nevada Bureau of Air Pollution Control (BAPC) found that:*

> *"Based on an EPA report and review of vendor information for wet and dry FGD processes, BAPC concluded that for higher sulfur coals wet scrubbing achieves better control, however, for lower sulfur Powder River Basin (PRB) coals, the efficiencies become so close as to be indistinguishable within their respective margins of error."[9]*

*Finally, it should be noted that Desert Rock has proposed hydrated lime injection prior to the fabric filter, so 96.2% is not achieved by the wet FGD alone.*

**Comment 20:**

Furthermore, experience at existing units burning low sulfur subbituminous coal and using wet scrubbers also demonstrates that they consistently achieve $SO_2$ emission rates much lower than the 0.095 lb/mmBtu limit proposed for Holcomb 2-4. The Navajo plant in Arizona, which fires subbituminous coal similar to the coal proposed for Holcomb, uses a wet scrubber and experiences $SO_2$ emission rates of less than 0.05 lb $SO_2$/mmBtu at Navajo units 1, 2, and 3 on a 30 day average. Periods of likely startup and shutdown are removed from the emissions data to compare the emissions to the limits proposed for Holcomb 2-4. The Navajo units' emissions do not exceed 0.06 lb/mmBtu with startup, shutdown and malfunction periods included.

Similarly, the Reid Garner plant in Nevada continuously achieves $SO_2$ emissions at rates much lower at its Unit 2 than the 0.095 lb/mmBtu limit proposed for Holcomb 2-4. See 2004-2006 $SO_2$ Emissions at Reid Gardner Unit 2. The Craig plant in Colorado was recently retrofitted with a scrubber on its second unit in 2005. Following the retrofit, Craig 2 has also consistently

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*[9] BAPC Response to EPA Region 9 Comments, Draft Operating Permit to Construct, AP4911-1349, Newmont Nevada Energy Investments, LLC – TS Power Plant.*

achieved $SO_2$ emissions lower than the 0.095 lb/mmBtu limit proposed for Holcomb 2-4. Craig achieves $SO_2$ emissions of approximately 0.06 lb/mmBtu.

The Clover Station in Virginia also operates a wet scrubber. For the last year of operation, Clover unit 1 has consistently achieved a 30-day $SO_2$ rate that is almost half of the proposed 0.095 lb/mmBtu limit for Holcomb 2-4. Clover 2 has consistently achieved $SO_2$ emissions lower much lower than the proposed 0.095 lb/mmBtu limit for Holcomb 2-4.

Lastly, the two units at the Intermountain Station in Utah that use a wet scrubber are achieving lower $SO_2$ emissions than the 0.095 lb/mmBtu limit proposed for Holcomb 2-4 on a regular basis. As the operator gains experience at these units, their average emission rate dropped from about 0.07 to about 0.05 lb/mmBtu. Id. The units have consistently achieved $SO_2$ emission rates near 0.055 lb/mmBtu on a 30-day rolling average for the most recent year.

***KDHE Response:***

*Holcomb project participant, Tri-State Generation and Transmission Association, operates the Craig Units. Based on the most recent ten months of operating data, the average of Units 1 and 2 together was 94.5% removal efficiency and 0.049 lb/mmBtu emission rate. The percent removal rate for the Craig Units is based on coal to stack criteria, not scrubber inlet to outlet, as there are no scrubber inlet monitors on these units. Measuring coal sulfur to scrubber outlet efficiency causes the efficiency to appear to be artificially higher than inlet to outlet scrubber efficiency measurement. (This is because not all sulfur in the fuel is converted to $SO_2$.) Holcomb Units 2-3 $SO_2$ removal efficiency will be using the inlet to outlet scrubber efficiency measurement method.*

*This commenter presents $SO_2$ CEMS data for various operating wet FGD systems and indicates that these emission rates should be the basis of the $SO_2$ BACT for Holcomb 2-3. The CEMS data presented are compiled from the beginning of 2004 through the first half of 2006. The maximum 30-day average $SO_2$ emission rates for the plants selected are shown in Table 7. Also included in Table 7 are $SO_2$ emissions data for facilities burning low sulfur coals that have wet FGD systems, which were prepared by the National Park Service (NPS).[10] Table 7 also shows the permitted limits for those facilities (all of which are higher than Holcomb 2-3).*

*The data in Table 7 illustrate the variability in the performance of wet FGD systems installed on generating units using low sulfur coal. The variability in performance exists among the various facilities as well as between time periods for a given generating unit.*

*The variability of performance of FGD systems is an important consideration in using emissions data to determine BACT limits. Permit emission limits require continuous compliance over the life of the facility. Operating conditions at a power plant change continuously with variations in the fuel chemistry, boiler conditions and output levels, FGD reagent quality, normal equipment wear, and other factors. The Nevada BAPC in its response to EPA Region 9 comments states:*

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*[10] NPS Comments on XCEL ENERGY – Comanche Power Plant Draft Permit, Memo from John Reber (NPS) to Jackie Joyce , November 23, 2005. Data is taken from Table 3.a $SO_2$ Rankings (30-day averaging period).*

*"Environmental Appeals Board (EAB) decisions confirm that BACT emission limits must be based on emission limits that can be achieved on a consistent basis. It is generally recognized that a permit emission limit must be greater than a level than can be achieved occasionally to account for source operational variability, including varying coal quality, long term performance of the plant and control units, and measurement uncertainty."*

*An example of the significance of a "safety margin" between operating data and permit levels is provided by the IPP Unit 3 permit. Operating data for IPP Units 1 and 2, as shown in Table 7, show a range of 30-day average $SO_2$ emission limits of 0.063 to 0.073 lb/mmBtu for the wet FGD systems operating at this facility. However, the permitted $SO_2$ emission limit for IPP Unit 3 is 0.09 lb/mmBtu. The $SO_2$ emissions levels shown in Table 7 for Navajo range from 0.055 to 0.091 lb/mmBtu; but the permit limit for the Navajo plant is 0.10 lb/mmBtu on an annual basis.*

***TABLE 7. $SO_2$ EMISSION LEVELS FROM OPERATING WET FGD SYSTEMS PRESENTED BY THE SIERRA CLUB AND THE NATIONAL PARK SERVICE (NPS)***

| ***Generating Unit*** | ***SC Highest 30-day Rolling Ave. (lb/mmBtu)[11]*** | ***NPS 30-day Averaging Period Year 2001 (lb/mmBtu)[12]*** | ***NPS 30-day Averaging Period Year 2002 (lb/mmBtu)[12]*** | ***Permitted Limit (lb/mmBtu) (30 day rolling)*** |
|---|---|---|---|---|
| *Bonanza Unit 1* | *Not Reported* | *0.068* | *0.071* | *0.15* |
| *IPP Unit 1* | *Not Reported* | *0.070* | *0.064* | *0.138* |
| *IPP Unit 2* | *Not Reported* | *0.073* | *0.063* | *0.138* |
| *Navajo Unit 1* | *0.056* | *0.091* | *0.053* | *0.10 (annual)* |
| *Navajo Unit 2* | *0.055* | *0.044* | *0.065* | *0.10 (annual)* |
| *Navajo Unit 3* | *0.059* | *0.064* | *0.071* | *0.10 (annual)* |
| *Reid Gardner U2* | *0.067* | *Not Reported* | *Not Reported* | *0.55* |
| *Reid Gardner U3* | *0.075* | *Not Reported* | *Not Reported* | *0.55* |
| *Craig Unit 2* | *0.064* | *Not Reported* | *Not Reported* | *0.16* |
| *Clover Unit 1* | *0.076* | *Not Reported* | *Not Reported* | *0.156* |
| *Clover Unit 2* | *0.086* | *Not Reported* | *Not Reported* | *0.156* |
| ***Range of All Units*** | ***0.055 to 0.086*** | ***0.044 to 0.091*** | ***0.053 to 0.071*** | |

*Table 8 lists $SO_2$ control efficiencies from operating coal-fired units using wet FGD on low sulfur coal, as supplied by the NPS.[13]*

*[11] These values were obtained from CEMS data over the period January 2004 through June 2006.*
*[12] It is not clear from the report data whether these values are the highest observed or average values.*
*[13] NPS Comments on XCEL ENERGY – Comanche Power Plant Draft Permit, Memo from John Reber (NPS) to Jackie Joyce , November 23, 2005. Data taken from Table 3.a $SO_2$ Rankings (30-day averaging period).*

*TABLE 8. $SO_2$ CONTROL EFFICIENCIES FROM OPERATING COAL-FIRED UNITS USING WET FGD AND LOW SULFUR COAL*

| ***Generating Unit*** | ***NPS 30-day Averaging Period Year 2001 (% Removal)*** | ***NPS 30-day Averaging Period Year 2002 (% Removal)*** |
|---|---|---|
| *Bonanza Unit 1* | *90.4* | *89.9* |
| *IPP Unit 1* | *91.5* | *92.2* |
| *IPP Unit 2* | *91.2* | *92.4* |
| *Navajo Unit 1* | *90.1* | *94.3* |
| *Navajo Unit 2* | *95.2* | *92.9* |
| *Navajo Unit 3* | *93.1* | *92.3* |
| ***Average*** | ***91.9*** | ***92.3*** |

*The average of all the removal efficiency data for Navajo, the most recent of the wet FGD installations presented in Table 7, is 93.0% . The data in Tables 4 and 6 support the argument that the performances of LSD-FGD and wet FGD on low sulfur coal are expected to be similar or only marginally better for wet FGD. The $SO_2$ BACT evaluation for Holcomb 2-3 assumed 92% removal efficiency for LSD-FGD technology and 93% for wet FGD on low sulfur coal. However, the tiered limit in the permit will result in 91-93% removal efficiency, which is consistent with the removal achieved with wet FGD on low sulfur coal as seen above.*

*Applying the above assessment of the operating data to the proposed Desert Rock limits, the performance data do not support the achievability of the Desert Rock limit of 0.06 lb/mmBtu (24 hour) with an appropriate operating margin or "safety factor." The data in Tables 5 and 6 above illustrate what is being achieved on a 30 day rolling average and these data do not support operating with a safety margin below 0.06 lb/mmBtu on a 30 day average basis, let alone 24 hour. It is well recognized that it is appropriate for the permitting agency to consider as part of the BACT analysis the extent to which the available data demonstrate whether the emission rate at issue has been achieved by other facilities over the long term. The emission limit is applicable for the facility's life, and the use of a safety factor in the calculation of a permit to take into account variability in fluctuation of performance has been supported by the EAB (Masonite, 5 EAD at 560 and Knauf II, 9 EAD at 15). Sunflower will need to do better than the tiered limits in the permit in order to ensure compliance.*

**Comment 21:**

The permit application for Holcomb units 2-4 acknowledges that a wet scrubber is capable of 93% control, compared to only 92% control for a dry scrubber. KDHE's Permit Summary Sheet also notes that a wet scrubber would achieve greater $SO_2$ removal at Holcomb, compared to a dry scrubber. This is consistent with all other comparisons of the relative removal efficiencies of both types of scrubbers. It should be noted, however, that wet scrubbers achieve much greater $SO_2$ reduction than the 93% assumed in the Holcomb application.

While all of these sources correctly recognize wet scrubbing as more effective at controlling $SO_2$ than dry scrubbing, many underestimate the control efficiency achievable with wet scrubbing. As the consultants for the applicant in the Weston Unit 4 PSD permit proceeding stated:

> "At Weston 4, we are anticipating an inlet $SO_2$ level in the range of 480 ppmvd (design) to 300 ppmvd (Black Thunder). In Japan, the current $SO_2$ emission limit is 10 ppmv (~0.02 lb/MBtu), and several plants are currently attaining that level using limestone wet FGD systems with inlet $SO_2$ values of 700 to 1200 ppmvd (double the Weston design). A 10 ppmvd equates to a FGD efficiency in the range of 97 to 98% for Weston. As we have discussed with B&W, the economic, if not technical, performance limit of a dry FGD system is around 0.08 lb/MBtu (35 to 40 ppmvd)…."

In other words, applicants are aware that dry scrubbing cannot achieve the low $SO_2$ emission rates required and being achieved in Japan.

***KDHE Response:***

*As discussed above in KDHE Response to Comment 19, it is misleading to claim that performance achieved for high sulfur coal applications is achievable at Holcomb 2-3.*

*With regard to the Weston 4, the limit is 0.10 lb/mmBtu, 30 day rolling average, which is higher than the Holcomb 2-3 limit. The Weston 4 permit is currently being modified to incorporate determinations made in response to an appeal before the State of Wisconsin Division of Hearings and Appeals. Jeffrey D. Boldt, Administrative law judge (the ALJ) found that:*

*"The control efficiency of 90% suggested by the Sierra Club's expert Dr. Phyllis Fox is accepted as BACT for this facility."*[14]

**Comment 22:**

Certain types of advanced wet scrubbers, particularly a jet bubbling reactor or magnesium enhanced lime scrubber, can achieve 99 percent or greater $SO_2$ removal. A number of facilities have installed the Chiyoda CT-121 jet bubbling reactor.

The jet bubbling reactor has been guaranteed by Chiyoda to achieve 99% $SO_2$ removal on three coal-fired boilers in Japan. Mitsubishi, a vendor of scrubber systems, reports it has guaranteed $SO_2$ removal efficiencies up to 99.8 percent, including four coal-fired boilers.

[14] *State Of Wisconsin Division Of Hearings And Appeals Findings Of Fact, Conclusions Of Law And Order, Summary item 1.b, page 2*

*KDHE Response:*

*On May 26, 2006, Sunflower provided KDHE with Supplement #2 Information Response to KDHE requests for additional information. Attachment 4 included in this supplement to the record is an engineering memorandum discussing the Chiyoda jet bubbling reactor (JBR) wet limestone scrubber prepared by Black and Veatch, the US licensee of this technology.*

*Black and Veatch indicates that the achievable removal efficiency for this type of scrubber is dependent on the inlet $SO_2$ concentration, so that numerical guarantees as to reductions are not any different than those proffered for a conventional wet FGD. In Table 9 (see page 6 of Attachment 4 to Supplement #2), Black and Veatch compares the $SO_2$ and $SO_3$ removal efficiency of LSD-FGD, wet FGD Spray Towers Option and Chiyoda FGD. Table 6 is an excerpt from the Black and Veatch comparison.*

***TABLE 9. $SO_2$ AND $SO_3$ CONTROL EFFICIENCIES COMPARISON (EXCERPTED FROM BLACK & VEATCH CHIYODA MEMO)***

| | ***LSD-FGD*** | ***Wet FGD (Spray Towers)*** | ***Chiyoda FGD*** |
|---|---|---|---|
| *$SO_2$ Removal* | *90-94% depending on $SO_2$ inlet concentration* | *90-95% for low sulfur fuels*<br><br>*95-98% for high sulfur fuels* | *90-95% for low sulfur fuels*<br><br>*95-98% for high sulfur fuels* |
| *$SO_3$ Removal* | *+90%* | *10% maximum* | *~15%* |

*This comment implies that because guarantees have been offered up to 99.8 percent removal efficiency that **ALL** installations could be offered such a guarantee. The guarantee would certainly be tied to fuel sulfur content and early applications for low sulfur fuels would likely be conservative, **i.e.**, at the low end of the expected performance range.*

*One factor in the selection of LSD-FGD over wet FGD that is described in detail in the Holcomb PSD application is the added benefit of controlling $SO_3$, a precursor to sulfuric acid mist and condensable particulate. It is clear from Black and Veatch's assessment that LSD-FGD is by far the superior technology for achieving this co-benefit.*

*The Black and Veatch memorandum emphasizes that Chiyoda is a specific manufacturer of a relatively new approach to the conventional wet FGD technology. Sunflower did address the more general category of wet FGD, and per KDHE request, further analyzed wet FGD technology, including Chiyoda. The result of the BACT analysis was the same.*

**Comment 23:**

Magnesium Enhanced Lime wet scrubbing technology also achieves $SO_2$ control of 99%. Documented experience at the Mitchell Station in Pennsylvania demonstrates that magnesium enhanced lime, a type of wet scrubbing, regularly achieves 99% control of $SO_2$.

***KDHE Response:***

*This comment implies that if this process were to be applied to Holcomb 2-3, 99% control of $SO_2$ could be achieved. It is misleading to claim that performance achieved for high sulfur coal applications is achievable at Holcomb 2-3. As noted in Sierra Club's Exhibit, the Magnesium Enhanced Lime (MEL) process has a proven ability to handle flue gases from burning of high sulfur (>4%) coal (see page 12 of Sierra Club Exhibit II). The data presented in Sierra Club Exhibit VV illustrates the removal achieved at high sulfur applications with a daily average inlet of 4.24 lb/mmBtu. This is nearly 3.5 times higher than the maximum inlet sulfur proposed for Holcomb 2-3. Although Exhibit II identifies facilities that use MEL, the exhibit does not provide an indication of the control effectiveness for the units or any information from which this could be derived and therefore does not contribute to the BACT analysis.*

**Comment 24:**

Wet scrubbing can achieve 99% control or greater on low sulfur coals. Even at the low 93% control assumed by the Developers and KDHE, it is the "top-ranked" add-on pollution control option for controlling $SO_2$ emissions at Holcomb units 2-4. Therefore, wet scrubbing must be used to establish BACT unless the applicant can overcome its significant burden of demonstrating that wet scrubbing should be rejected due to unique conditions at the Holcomb site.

***KDHE Response:***

*This commenter asserts that wet FGD is the "top ranked" pollution control option based on the mistaken assumption that percent $SO_2$ reductions achievable on high sulfur applications are also achievable when applied to low sulfur coal. The contention that wet FGD is the top pollution control technology is not sound.*

*Many state regulatory agencies have addressed the relative $SO_2$ removal efficiencies of wet and dry FGD as part of recent PSD permit reviews. State agencies that have concluded that the $SO_2$ removal efficiencies of wet and dry FGD are comparable or marginally higher for wet FGD systems installed at low sulfur coal projects include: the Wisconsin Department of Natural Resources (Weston 4), Nevada Department of Environmental Protection (Newmont Nevada Energy Investments), Missouri Air Pollution Control Program (City Utilities of Springfield), and Louisiana Department of Environmental Quality (Big Cajun II, Unit 4). For example, the Nevada BAPC, in addressing the differences in performance between wet and dry FGD on low sulfur coal, stated:*

*"Based on an EPA report and review of vendor information for wet and dry FGD processes, BAPC concluded that for higher sulfur coals wet scrubbing achieves better control, however, for lower sulfur Powder River Basin (PRB) coals, the efficiencies become so close as to be indistinguishable within their respective margins of error."*[15]

*Sunflower selected LSD-FGD with a fabric filter as the control technology for $SO_2$ at Holcomb over wet FGD system with a fabric filter system preceding the wet FGD system. Sunflower's analysis indicates that the $SO_2$ emission rate attainable with a wet FGD system is likely to be only slightly lower than that attainable with a LSD-FGD system. A wet FGD system could be expected to attain removal of up to one percentage point more $SO_2$ from the low sulfur coal to be used at Holcomb, compared to a LSD-FGD system. This finding is consistent with the data presented in Tables 4 and 6 of this response and with the findings of other regulatory agencies. The tiered approach which is used in the final permit maximizes the removal efficiency with respect to fuel sulfur content. As shown in Sierra Club exhibit S6, performance efficiency decreases below 95% starting at an inlet of approximately 1.25 lb $SO_2$ /mmBtu (See figure 4.3-1, page 12). A similar fall off in performance can be expected for wet FGD.*

*The LSD-FGD system was selected because it provides the best overall results, considering $SO_2$ emissions and other factors. Consideration of other collateral impacts is specifically provided for in the Clean Air Act (CAA) as noted by Sierra Club. Factors considered do not have to be "unique" to be considered. That is, regional issues and fuel concerns are valid grounds for rejection of wet FGD.*

*Sunflower identified the following site-specific considerations that affect the choice of FGD technology at Holcomb, and these factors were discussed in the Holcomb PSD Permit Application at Section 4.0, pages 4-6 to 4-11 and 4-35 to 4-39.*

- *Integration of operations and infrastructure of the FGD systems for Holcomb 2-3 with the existing systems and equipment at Holcomb. These systems and equipment include: lime unloading and storage, waste powder handling, solid waste disposal (landfill), and the experience of the Holcomb operating staff;*
- *Compliance with the zero-discharge NPDES permit, which is based in part on the integration of the LSD-FGD system into the plant water balance;*
- *Impracticality of sales of by-product gypsum into any local market, given the remote location of the plant;*
- *Reliance on supplies of low-sulfur coal, which while not unique to the Holcomb site, is a site-specific consideration.*

*Sunflower considered the following general, non-site-specific factors in selecting LSD-FGD as BACT for Holcomb:*

- *Ground level pollutant concentrations*

[15] *BAPC Response to EPA Region 9 Comments, Draft Operating Permit to Construct, AP4911-1349, Newmont Nevada Energy Investments, LLC – TS Power Plant.*

- *Emissions of sulfuric acid mist (SAM), $PM_{10}$, and Hazardous Air Pollutants (HAP)*
- *Energy consumption*
- *Cost*
- *Plume visibility*
- *Water consumption*
- *Water discharge*
- *Waste product volume*

*Consideration of these other factors is specifically delineated in the CAA.*

*In other recent actions, environmental, energy, and economic considerations have been accepted for the specific rejection of wet FGD over the selection of LSD-FGD as the appropriate $SO_2$ technology. For example, the BAPC responded to EPA Region IX's concerns,*

> *"Thus because the economic and environmental benefits of a dry scrubber far outweigh the best case estimated modest improvement in $SO_2$ control achieved by a wet scrubber …BAPC believes that a dry scrubber is BACT for this project, just as originally set forth in its PSD permit BACT analysis[16]."*

*Notably, when the final permit was appealed to EPA's EAB this portion of the action was not challenged.*

**$SO_2$ BACT and Emission Limits (SCC III B c i)**

**Comment 25:**

A wet scrubber cannot be rejected as the basis of BACT due to environmental impacts. In addition to failing to demonstrate that the impacts from wet scrubbing would be unique to the Holcomb Station site, the Developers fail to demonstrate the impacts. The claims of adverse environmental impacts associated with wet scrubbing justify rejecting wet scrubbing as the basis for BACT.

Wet scrubbing does not result in increased SAM emissions. The typical claim by permit applicants seeking to avoid a BACT limit based on wet scrubbing is that wet scrubbing results in greater SAM emissions.

***KDHE Response:***

*The LSD-FGD system was selected because it provides the best overall results considering $SO_2$ emissions and other factors, including SAM emissions. As can be seen from Table 9 above, LSD-FGD is undeniably the best technology choice for controlling $SO_3$, the precursor of SAM.*

[16] *BAPC Response to EPA Region 9 Comments, Draft Operating Permit to Construct, AP4911-1349, Newmont Nevada Energy Investments, LLC – TS Power Plant.*

*It is important to look at an "apples to apples" comparison, not "apples to oranges." The comment, "When wet scrubbing is used, it is almost always combined with a PM control device, such as a wet ESP" is misleading. Both wet and dry FGD are typically combined with a PM control device, but the configuration is different, with the PM control device preceding the wet FGD and the PM control device following the dry FGD (see figure on page 4-33 of Section 4.0 of Holcomb PSD Application). While a wet ESP is often included in new power projects burning high sulfur coal that also use a wet FGD system, that has not been the practice for low sulfur coal projects using wet FGD systems. For example, none of the wet FGD systems listed in Tables 5 and 6 of this response include a wet ESP. When the wet ESP is installed, it is not the primary PM control device but rather follows the wet FGD for SAM control. It should also be noted that in addition to the fabric filter/wet FGD system proposed for Desert Rock, this project also includes the use of sorbent injection upstream of the fabric filter for sulfuric acid control in order to obtain the same SAM emission rate as Holcomb.*

*Much of the sulfuric acid contained in the flue gas entering both LSD-FGD and wet FGD systems will condense and form sub-micron aerosols as the flue gas temperature decreases, due to the evaporation of water used to create reagent slurries in each system. In an LSD-FGD system, the sulfuric acid aerosols are collected by the high efficiency fabric filter installed downstream of the FGD system. The filter cake formed on the filter bags also contains unreacted lime, which further reduces sulfuric acid emissions. As described above, wet FGD systems installed on low sulfur coal projects do not have a particulate collection device downstream of the wet FGD (e.g., wet ESPs) which can collect the sulfuric acid aerosols created in the wet scrubber. Scrubber modules in wet FGD systems do remove some of the sulfuric acid mist. However, the collection efficiency for the fine aerosols is much less than a fabric filter. The removal of the sulfuric acid aerosols across a wet scrubber module can vary widely, depending upon the design and operation of the FGD system. Sulfuric acid removal efficiencies from 15% to 80% have been reported in the literature.*

**Comment 26:**

Water use is not a unique concern for this facility. Moreover, many other states have equal or greater water quantity concerns than Kansas, and yet, coal-fired power plants in those states use wet scrubbing. For example, the Craig Station in Colorado uses wet scrubbing, as will the Desert Rock plant in Arizona. Both Colorado and Arizona are arid states. In other words, relative water scarcity is not unique to the Holcomb site and it cannot be used to justify rejection of wet scrubbing at Holcomb.

***KDHE Response:***

*Water consumption was included among the factors considered in the control technology evaluation. Water usage was not the primary reason for rejection of the wet FGD. The evaluation was holistic in approach, and all factors were considered together.*

**Comment 27:**

If a visible plume and alleged higher ground level concentrations of pollutants due to less dispersion were truly a concern, the applicant could use stack gas reheat to raise the temperature of the gases above the condensation point. The application did not disclose this option.

***KDHE Response:*** *The moisture plume visibility from a wet scrubber is much greater than a dry scrubber in cold weather. However, this factor was not the primary reason for rejection of wet FGD. The evaluation was holistic in approach and all factors were considered together.*

**Comment 28:**

Wet scrubbing achieves better mercury control, which is important for a top-down BACT analysis. Wet scrubbing also avoids the high short-term $SO_2$ emission rates attributable to atomizer change-out at a dry scrubber. Wet scrubbing creates a reusable byproduct and does not contaminate the flyash from the system.

***KDHE Response:***

*The permit application did not address the co-benefits of any control technology in the top-down $SO_2$ BACT with respect to mercury. This was excluded because Sunflower is not going to rely solely on the selected FGD system for mercury control and because there is no significant co-benefit attributable to either wet scrubbing or LSD-FGD when burning subbituminous coal. In fact, a noted expert, James E. Staudt, Ph.D has testified that:*

> *"…boilers that fire subbituminous coal…are not likely to achieve high levels of mercury removal from co-benefits alone. …For subbituminous coals, such as Powder River Basin (PRB) coals that are used widely in Illinois, halogenated PAC has been shown to be very effective at several full-scale coal-fired boiler installations providing 90% or more removal."*[17]

*In order to achieve the high mercury removals required in the permit, activated carbon injection (ACI) will be utilized or bituminous coal blending may potentially be used. Even if a wet scrubber were selected, ACI would be required as well. The Weston report (Sierra Club Exhibit L) assumes a fabric filter upstream of the wet FGD system, which is the most logical combination of particulate control and wet FGD for PRB units. EPA's Information Collection Request (ICR) as part of the development of the federal Clean Air Mercury Rule*[18] *showed that a fabric filter alone, without the Spray Dryer Absorber (SDA) to remove chlorine from the flue gas, removed about 72% of the inlet mercury. Therefore, a subbituminous coal-burning unit equipped with a fabric filter, followed by a wet FGD, might be expected to remove*

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[17] *James E. Staudt, Ph.D Pre-filed Testimony R06-25 (Rulemaking – Air) Proposed New 35 Ill. Adm. Code 225 Control Of Mercury Emissions From Large Combustion Sources:* *http://www.ipcb.state.il.us/cool/external/CaseView2.asp?referer=coolsearch&case=R2006-025*

[18] *Control of Mercury Emissions from Coal Fired Electric Utility Boilers: An Update, Air Pollution Prevention and Control Division, National Risk Management Research Laboratory, Office of Research and Development, U.S. Environmental Protection Agency, Research Triangle Park, NC February 18, 2005, page 44*

*approximately 72% as shown in Exhibit L. That is to say, the mercury removal may not be due to the wet scrubber, as claimed, but rather due to the upstream fabric filter.*

$SO_2$ BACT and Emission Limits **(SCC III B c ii)**

**Comment 29:**

A wet scrubber cannot be rejected based on cost effectiveness. A top-ranked control option, in this case a wet FGD, cannot be rejected merely because it costs more, in absolute terms, than the less-effective dry FGD. Rather, a top control option can only be rejected for economic reasons if an applicant can demonstrate that the cost-effectiveness (i.e., dollars per ton of pollutant removed) is above the levels experienced by other sources.

***KDHE Response:***

*This comment asserts that cost cannot be considered in order to reject the top ranked control option. There are a number of factors that make the costs associated with wet FGD higher than that experienced by others. For example, the existing lime unloading and storage system was designed to accommodate future expansion. This is a significant cost saving benefit to the scope of the project. Or stated another way, this is a site specific factor that adds significant cost to wet FGD that is not added to the cost of the selected control technology, LSD-FGD.*

*The existing landfill is already designed and permitted for waste from a dry scrubber. Selecting wet FGD would require redesign and permit modifications that are costly and not required for dry FGD. Again, this is a site specific factor with a cost penalty if wet FGD is selected. Similar points can be made with respect to the integration of the LSD-FGD system into the plant water balance and the impracticality of sales of by-product gypsum into any local market, given the remote location of the plant.*

*The holistic approach to comparison of control technology entails looking at the benefit of achieving the reduction of SAM without the need for an additional control device or process. If the same level of control can be achieved with the proposed LSD-FGD/fabric filter configuration as can be achieved with the Desert Rock configuration (hydrated lime/fabric filter/ wet FGD), then the cost effectiveness of the selected configuration for Holcomb 2-3 becomes even more apparent.*

*Despite claims to the contrary, incremental cost is appropriate to consider in a situation such as this where the "top" control has only a minimal reduction in emissions as compared to the selected technology. As stated above, recent decisions have found that for low sulfur coal the differences in the efficiencies of LSD-FGD versus wet FGD are effectively indistinguishable. To the extent that the BACT analysis submitted by Sunflower assumed that wet FGD was slightly better (~1%), the reduction in emissions by selecting wet FGD would be only 242 tons per year (less than 1%). The tiered emission limit in the final permit will result in substantially better reduction than the assumptions in the Holcomb PSD application.*

**$SO_2$ BACT and Emission Limits (SCC III B c iii)**

**Comment 30:**

A wet scrubber cannot be rejected based on energy impacts. Wet FGD cannot be rejected as BACT based on collateral energy use. Regardless of whether energy use was included in the cost-effectiveness analysis, if wet scrubbing uses more energy to run than dry scrubbing, that additional energy use cannot justify rejecting wet scrubbing technology as the basis for BACT.

***KDHE Response:***

*Energy impacts were included among the factors considered in the control technology evaluation. Energy impacts are not the primary reason for rejection of the wet FGD. The evaluation was holistic in approach, and all factors were considered together.*

**$SO_2$ BACT and Emission Limits (SCC III D)**

**Comment 31:**

Even if $SO_2$ BACT is established based on a dry scrubber, the limit must be lower than 0.095 lb/mmBtu. The draft permit establishes an $SO_2$ limit of 0.095 lb/mmBtu, based on a 30-day average, excluding startup, shutdown and malfunction. This does not represent BACT, even if the less effective dry scrubber is used to establish BACT.

Assuming that a dry scrubber is the top-ranked $SO_2$ control for Holcomb 2-4, the proposed 0.095 lb/mmBtu limit is not the maximum degree of reduction achievable with a dry scrubber. Since 85% of fuel sulfur content is transformed into $SO_2$, and a dry scrubber achieves at least 92% control, the resultant maximum degree of reduction is less than 0.062 lb/mmBtu.

***KDHE Response:***

*This comment is similar to the concerns raised by Comment 1. The draft permit was revised to include a 2-tiered emission limit for $SO_2$. The revised emission limit and the basis for the limit are discussed in response to Comment 1.*

*The assumed 85% conversion of fuel sulfur content is not a constant, but rather the conversion varies with source. This conversion can vary between 85 and 95%.*

*As discussed in detail in the response on the rejection of wet FGD, control efficacy of scrubbers, both wet and dry, is lower with low sulfur coal. It is not reasonable to assume at least 92% is achievable at all fuel sulfur contents.*

*The emission limits in the permit are based on consideration of LSD-FGD technology, historical LSD-FGD performance information and their relationship to appropriate emission limits, contained in other recent comparable PSD permits. The two-tiered limit will ensure that, for the majority of the fuel supply proposed, Holcomb 2-3 will operate below 0.065 lb/mmBtu on a 30-*

*day rolling average basis, thus maximizing the $SO_2$ reduction within the range of fuel sulfur content most likely to be burned. Such an emission limit properly accounts for the possible range of fuel sulfur conversion to $SO_2$.*

**Comment 32:**

Even if dry scrubbing were selected as the top-ranked control option for $SO_2$, the BACT limit must be no higher than 0.069 lb/mmBtu, based on the significant operating experience at Alta Vista.

***KDHE Response:***

*The permit has a tiered emission limit for $SO_2$ that will provide for lower emission limits with lower sulfur coal and maximize the $SO_2$ reductions across the range of fuel proposed for Holcomb 2-3. Please refer to the response to Comment 1 for further information.*

*The only operating data provided to support the argument that "other plants utilizing dry scrubbers are achieving much lower $SO_2$ emission rates than the 0.095 lb/mmBtu limit" is from the Alta Vista plant. The Alta Vista plant has a permitted emission limit of 0.187 lb/mmBtu on a 30 day rolling average basis (compared to Holcomb's tiered limit of .065 /.085 lb/mmBtu, 30 day rolling). A review of Sierra Club's Exhibit FFF reveals that a significant portion of the daily $SO_2$ emissions were eliminated from the 30-day rolling average calculation. Therefore the conclusion that the highest 30-day rolling average is 0.069 lb/mmBtu is questionable. Multiple days were excluded from the calculations, and the 30-day rolling average calculations in the spreadsheet indicates that commenter incorrectly averaged in days during which no operations occurred. The 30-day rolling averages as calculated by the commenter indicate that emissions would be over 0.060 lb/mmBtu during approximately 23% of the period reported and would be over 0.065 lb/mmBtu for 9% of the periods (days) reported. Because the emission limit of the lower of the two tiers in the final Holcomb 2-3 permit is 0.065 lb/mmBtu, these operating data would tend to support that the limit in the final Holcomb 2-3 permit is consistent with the operating capability of a dry FGD system, and is achievable.*

**Comment 33:**

The control efficiency required of a scrubber to meet a static permit limit, like 0.095 lb/mmBtu, depends on the $SO_2$ inlet concentration to the scrubber. While a scrubber may have to operate at maximum control (i.e., maximum degree of reduction) at maximum sulfur inlet concentrations to achieve a static emission limit, it can operate at much lower efficiencies when the inlet concentration decreases.

To ensure BACT (i.e., maximum degree of reduction), the permit must include either an $SO_2$ removal requirement, or establish different emission limits based on the various inlet concentrations to the scrubber.

***KDHE Response:***

*This concern has been addressed in the permit by choosing the latter of the two options suggested. The permit includes a tiered emission limit for $SO_2$ that will provide for lower emission limits with lower sulfur coal and maximize the $SO_2$ reductions across the range of fuel proposed for Holcomb 2-3. Please refer to the response to Comment 1.*

*The EAB reiterated in the Order Denying Review of PSD Appeal No. 05-04, Newmont Nevada Energy Investment LLC*[19] *that permitting agencies have discretion in determining whether a particular control efficiency level is appropriate in determining the best control technology and in setting an appropriate emissions limit.*

> *"…the [permit issuer] has discretion to base the emissions limitation on a control efficiency that is somewhat lower than the optimal level. … There are several different reasons why a permitting authority might choose to do this. One reason is that the control efficiency achievable through the use of the technology may fluctuate, so that it would not always achieve its optimal control efficiency.*
>
> *… a permitting authority must be allowed a certain degree of discretion to set the emissions limitation at a level that does not necessarily reflect the highest possible control efficiency, but will allow the permittee to achieve compliance consistently." i*n re Masonite Corp.*, 5 E.A.D. 551, 560-561 (EAB 1994).*

*As noted elsewhere in this response and also in Sierra Club Exhibit S6, the expected control efficiency range for LSD-FGD is 92-95% depending on the inlet $SO_2$ concentration. Thus the control efficiency would be expected to fluctuate when the inlet $SO_2$ concentration varies. In fact, the EAB notes in the Newmont decisions*[20]*:*

> *"…As we noted in* Masonite*, where the technology's efficiency at controlling pollutant emissions is known to fluctuate, setting the emissions limitation to reflect the highest control efficiency would make violations of the permit unavoidable.*
>
> *…Instead, permit writers retain discretion to set BACT levels that do not necessarily reflect the highest possible control efficiencies but, rather, will allow permittees to achieve compliance on a consistent basis."*

*Therefore, it is inappropriate to establish a permit limit for $SO_2$ removal efficiency that would be difficult to consistently achieve unless the lowest removal efficiency were selected.*

**Comment 34:**

Dry scrubbers achieve greater than the 92% $SO_2$ removal efficiency that KDHE assumes when setting the BACT limit for Holcomb 2-4 based on dry scrubbing. Alstrom recently quoted a

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*[19] See Order Denying Review , PSD Appeal No. 05-04, page 42-43*
*[20] See Order Denying Review , PSD Appeal No. 05-04, page 18*

93.1% expected control efficiency from a dry scrubber bid for the Newmont Mining facility in Nevada. Wheelabrator similarly quoted a minimum removal efficiency of 93% for the Newmont Mining plant.

***KDHE Response:***

*This comment refers to the Alstom bid as quoting a 93.1 % control efficiency for Newmont as evidenced by Exhibit T. This Exhibit is an indicative bid for the Newmont (if it was called the Boulder Valley project). Sierra Club has calculated the control efficiency from the expected operating condition (inlet $SO_2$ of 2230 lb/hr) and expected $SO_2$ emissions (156 lb/hr) so this is the expected performance at this set of conditions only, not the control efficiency that would be expected across the range of possible operating conditions. As an indicative bid, this is not a guarantee but rather an indication of price and maximum expected performance given a limited amount of preliminary information and technical data. Alstom closes the bid document with the following statement:*

> *"This submittal contains preliminary technical data and indicative information, and is not a firm quote or offer to perform the work. Alstom Power, Inc reserves the right to amend its information and submittal based on technical, commercial and any other consideration its management deems necessary or appropriate." (Sierra Club Exhibit T, page 11)*

*Similarly, the Wheelabrator quote is a "budget proposal" based upon specific conditions only (0.98 lb/mmBtu $SO_2$ inlet and 0.069 lb/mmBtu $SO_2$ emissions); not the conditions and control efficiency that would be expected across the range of possible operating conditions for the facility. Thus, the proffered vendor data only confirms that dry scrubbers may achieve greater than 92% $SO_2$ removal under specific operating conditions.*

*In summary, the 2-tiered $SO_2$ limit contained in the permit is responsive to the concerns raised and is within KDHE's discretionary authority in determining BACT.*

**Visible Emission Limit (SCC III E)**

**Comment 35:**

The permit does not include the required visible emission limit. When issuing a construction permit to a "major stationary source," KDHE must include a limit that represents BACT for each regulated pollutant. More specifically, a BACT limit is required for $PM/PM_{10}$ and SAM emissions.

Typically, BACT limits are expressed as emission rates (i.e., pounds per hour or pounds per million Btu heat input). However, BACT is not restricted to emission rate limits. In fact, BACT is specifically defined as "including a visible emissions standard." 40 C.F.R. § 52.21(b)(12) ("Best available control technology means an emissions limitation (including a visible emission standard)…"), incorporated into the Kansas SIP at K.A.R. 28-19-350(b).

A visible emission standard is a limit on “light scattering particles” in the emissions from a source. At least two types of pollutants constitute “light scattering particles,” and therefore “visible emissions”: fine PM and SAM aerosols. Other facilities have BACT limits for visible emissions. For example, the Springerville facility in Arizona has a BACT limit of 15% opacity, the Mid-America facility in Council Bluffs has an opacity limit of 5 percent, and the Desert Rock permit includes a 10% BACT limit for opacity.

The Holcomb 2-4 permit fails to include a visible emission limit for PM and sulfuric acid mist based on BACT. While the permit includes an opacity limit, the limit is based on NSPS and does not constitute BACT. A complete BACT limit for PM and SAM requires a 5% opacity limit, similar to the Council Bluffs permit.

***KDHE Response:***

*This commenter appears to assume that the parenthetical inclusion of a visible emission standard creates a mandate to apply such a standard in every circumstance. The issue therefore is whether the language requires an opacity limit to be set as BACT or merely allows an opacity limit to be set as BACT.*

*The definition of BACT in the Clean Air Act does not include the parenthetical phrase in question. It simply states that BACT is an emission limitation for each pollutant subject to regulation. Since opacity is not a pollutant, there is not a statutory obligation to set an opacity limit. This perspective is supported by judicial language such as:*

> *“The word ‘include’ is sometimes used merely to specify particularly that which belongs to the genus already expressed in more general terms, and sometimes to add to the general class a species which does not naturally belong thereto...“ Illinois Central R. Co. v. Franklin County, 56 N.E.2d 775, 781.*

*A court would not be able to construe the definition to include visible emission standards if this parenthetical phrase was not placed in the regulation. In this case, the general term is “emission limitation” and the parenthetical adds to that the visibility standard which does not naturally belong to the class. The Federal definition of emission limitation does not refer to visible indicators of air pollution, but to actual measurable requirements with respect to the pollutants themselves:*

> *“The terms ‘emission limitation’ and ‘emission standard’ mean a requirement established by the State or the Administrator which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction, and any design, equipment, work practice or operational standard promulgated under this chapter…” 42 U.S.C. 7602*

*In Alabama Power Co. v. Costle (606 F.2d 1068 (1979)) in which this specific provision was challenged by industry, the court agreed with EPA that the parenthetical term did not create a mandate to include a visible emission standard to every facility. The court specifically stated:*

> *"In our view, industry petitioners misconstrue the import of inclusion of the parenthetical phrase within the regulation's definition. BACT is defined, in general, as a level of control technology appropriate to the facts and circumstances of the particular permit applicant. EPA is correct in its view that, where appropriate, BACT may include a visible emissions standard [Cites omitted]. Application of BACT requirements is subject to appropriate court review on a case-by-case basis. We do not construe the regulations as requiring inclusion of a visible emissions standard in every case." 606 F.2d, at 1086-1987.*

*The commenter acknowledges that fine PM and SAM aerosols are "light scattering particles" and that a visible emission standard is a limit on light scattering particle emissions from a source.*

*In the case of Weston 4, the decision of the State of Wisconsin Division of Hearing and Appeals held that:*

> *"The compliance provisions, particularly those for mercury and particulate emission limits for the SCPC boiler, are reasonable and consistent with applicable administrative code provisions and other recently issued permits. Further, any visible emissions requirements for PM and SAM are met and achieve BACT by virtue of the direct emission limits on these pollutants."[21]*

*A consultant for the commenter in the Weston 4 case, Dr. Phyllis Fox, concurred that requiring emission limits on PM and SAM will have the effect of reducing visible emissions of these pollutants. Thus, to the extent a visible emissions standard is required, the Holcomb permit establishes BACT for PM and SAM visible emissions by establishing direct numeric emissions limitations (expressed in lb/mmBtu) for those pollutants.*

*The majority of recent permits do not include a BACT limit for opacity. Rather most permits include NSPS and, where applicable, a state standard for opacity. Of the permits reviewed as part of KDHE evaluation of BACT, thirty one [22] included only NSPS or state standards for opacity and only six included BACT or in some other way related opacity to BACT. Of these six, two permits require opacity monitoring as an indicator of compliance with the PM limits (Sevier and Intermountain Power Project Unit 3), two are set as a result of a Settlement Agreement with Sierra Club (Dallman Unit 4) or another environmental organization (Comanche Unit 3), one stated that BACT for PM, $SO_2$ and $NO_x$ are more stringent than NSPS for BACT (Big Cajun II Unit 4) and one set BACT equivalent to NSPS (Longleaf). The overwhelming majority of recent permits are issued without a BACT limit for opacity, consistent with the Holcomb 2-3 permit.*

*The permits cited by the commenter do not support that BACT is required for opacity. The Springerville permit does include a 15% opacity limit. However, this is a restatement of the*

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[21] *In the Matter of an Air Pollution Control Construction Permit Issued to Wisconsin Public Service Corporation for the Construction and Operation of a 500 MW Pulverized Coal-Fired Power Plant Known as Weston Unit 4 in Marathon County, Wisconsin Dated at Madison, Wisconsin on February 10, 2006.*

[22] *Prairie State, Nebraska City, Weston 4, Elm Road, Newmont, Harding, Cross Units 3 and 4, Sandy Creek, Longview, Whelan, Thoroughbred, Indeck Elwood, Oak Grove, Desert Rock, Big Stone II, Iatan, Roundup, Wygen II, Dry Fork, TXU standard plants (8 units), Hugo Unit 2, and Wygen III.*

*original opacity limit established for Springerville Units 1 and 2 (Approval to Construct dated December 21, 1977) which excludes periods of startup, shutdown, and malfunction. This is not a BACT limit because the condition cites 40 CFR 60.11, which is an NSPS, as the authority.*

*The Technical Support Document for the Council Bluffs permit includes the following statement as the basis for setting a BACT limit for opacity: " According to 40 CFR §52.21(b)(12), BACT includes an emission limitation for visible emissions." This is not the correct interpretation of the regulation.*

*Although the Desert Rock proposed permit does include a 10% limit for opacity, this does not mean this is a BACT limit. Sierra Club's Exhibit K includes a summary table of the BACT limits for Desert Rock which does not include opacity and the evaluation of the SAM and PM/$PM_{10}$ BACT do not mention opacity even as a surrogate.[23] There is no mention of opacity in Exhibit K, thus the opacity limit is not BACT.*

*In summary, the parenthetical inclusion does not require BACT for opacity. The final permit includes BACT limits for PM and SAM, which will have the effect of reducing visible emissions and opacity. There is also an NSPS opacity limit in the final permit, which is consistent with the majority of other PSD permits issued.*

**Sulfuric Acid Mist (SAM) BACT and Emission Limits (SCC III F)**

**Comment 36:**

The SAM limit in the permit does not represent BACT. SAM is a regulated pollutant subject to BACT. The Draft Permit sets a SAM emission limit from the boiler at 0.004 lb/mmBtu. The limit does not represent BACT.

Sierra Club is aware of at least two control options that are applicable and must be considered in a BACT analysis for SAM. First, a lower conversion SCR catalyst could be used, one achieving less than 0.5% $SO_2$ to $SO_3$ conversion, rather than the 1.5% assumed in the Holcomb BACT analysis. This would lower the SAM BACT limit to 0.002 lb/mmBtu. Second, a wet electrostatic precipitator (ESP) designed to remove at least 90% of the SAM exiting the dry FGD baghouse could be used. This would lower the SAM BACT limit to 0.0004 lb/mmBtu.

Other facilities have been permitted with lower SAM limits. The Newmont Mining plant in Nevada has a BACT limit for SAM of 0.001 lb/mmBtu. The Parish Unit 8 facility in Texas has a SAM limit of 0.0015 lb/mmBtu, the Santee Cooper Cross plant has a limit of 0.0014 lb/mmBtu, the SEI Birchwood plant has a limit of 0.002 lb/mmBtu and the AES Puerto Rico facility has a limit of 0.0024 lb/mmBtu. There is no indication that Holcomb units 2-4 are substantially different than any of these plants, especially the Newmont Mining plant. Therefore, it must be presumed that BACT for Holcomb is no greater than 0.001 lb/mmBtu.

[23] See Sierra Club Exhibit K, Table 8 on page 30, PM BACT evaluation pages 24 through 27, and SAM BACT on page 28 and 29.

A BACT analysis must determine the best control option for each pollutant, and must consider higher-ranked, more effective control options like wet ESP and sorbent injection. However, no BACT analysis was conducted for the Holcomb units.

There are a number of facilities that use wet ESP to control SAM emissions. In addition to greater SAM control, use of a wet ESP also removes 95% to 97% of the $PM_{10}$ as well as mercury and other HAPs. Wet ESPs have been applied to pulverized coal plants, including Sherbourne County and other plants.

***KDHE Response:***

*This comment asserts that the proposed SAM limit for Holcomb is not based on a "top-down BACT analysis." This is inaccurate; a top-down BACT analysis was conducted for SAM.*

*Section 4 of the PSD Permit Application contains a BACT analysis for SAM. Sunflower considered dry FGD and fabric filter, wet FGD and ESP, and wet ESP alone as alternative technologies for control of SAM. The dry FGD and fabric filter was selected as the most effective technology. Wet ESP was rejected because such a system has not been demonstrated and the expected inlet $SO_3$ levels into such device (to be installed downstream of the dry FGD system and fabric filter system) would be so low that little removal would take place (Section 4 of the PSD Permit Application pages 4-73 and 4-74).*

*Both the SAM limits in other permits and the effectiveness of the selected control technology were considered in determining the BACT emission limit, the last step in the BACT analysis process. The calculation of the BACT limit based on engineering evaluation of the $SO_3$ formation and removal process is presented in Section 4 of the PSD Permit Application at page 4-77. The calculation assumes that the dry FGD and fabric filter achieves 90% reduction in SAM emissions.*

<u>*Low Conversion SCR:*</u> *The commenter argues that emissions of SAM might be reduced by use of a "lower conversion SCR catalyst." Conversion of $SO_2$ to $SO_3$ does vary between catalysts. However, the development of these catalysts is at an early stage. For example, one of the first efforts to reduce $SO_2$-$SO_3$ conversion was at the Gavin plant, where an improved catalyst was tested on an eastern bituminous coal beginning in 2005.[24] The final permit $NO_x$ emission limit for Holcomb is at the lower end of the operating range of existing SCR systems. The imposition of an additional restriction on $SO_2$ conversion rate in selection of the catalyst is not a demonstrated technology.*

<u>*Technical Feasibility of wet ESP:*</u> *As explained in the air permit application, wet ESPs have only been used to control sulfuric acid mist from power plants burning high sulfur fuels. The coal-fired power plants being permitted with wet ESPs use high sulfur coal and use a wet FGD system for $SO_2$ control. KDHE has not documented any PRB coal fired facilities equipped with a wet*

[24] *Application and Operating Results of Low SO2 to SO3 Conversion Rate Catalyst for DeNOx Application at AEP Gavin Unit 1 Anthony C. Favale, P.E. Presenter Hitachi Power Systems America Ltd., 645 Martinsville Rd., Basking Ridge, NJ 07920. Proceedings of the 2006 Environmental Controls Conference, U.S. Department of Energy National Energy Technology Laboratory.*
*http://www.netl.doe.gov/publications/proceedings/06/ecc/pdfs/Favale_Summary.pdf*

*ESP for sulfuric acid control.*[25] *High sulfur coal facilities produce higher concentrations of sulfuric acid due to the higher sulfur content of the fuel. As the flue gas passes through the wet FGD system, the sulfuric acid condenses and forms a fine aerosol. Due to the relatively poor collection efficiency of these aerosols in the wet scrubber (generally < 50%), a relatively large concentration of sulfuric acid mist can exit the stack. The use of a wet ESP in these cases can result in high sulfuric acid* ***mist*** *removal. The wet ESP will provide little, if any control, of* ***vapor*** *phase sulfuric acid.*

*In a PRB coal-fired power plant equipped with a dry FGD and fabric filter system, the SAM exiting the stack is much lower due to the lower sulfur content of PRB coals, the high alkalinity of PRB coal ash, and the high SAM removal capability of the dry FGD and fabric filter system. The fabric filter is the last air pollution control device before the flue gas exits the stack. Due to the extremely high collection efficiency of the fabric filter, very little of the sulfuric acid exiting the fabric filter is expected to exist as a* ***mist or aerosol****, which could potentially be collected by a wet ESP, if installed downstream of the fabric filter. The wet ESP is expected to remove little, if any of the vapor phase sulfuric acid. Since a wet ESP has not been installed downstream of a dry FGD and fabric filter system, it is speculative at best to assume high levels of sulfuric acid removal efficiency for this configuration. It is also expected that obtaining meaningful commercial guarantees for sulfuric acid removal for this configuration from equipment suppliers would be problematic. It is likely that any guarantees, if even offered, would be tied to flue gas conditions at the inlet to the wet ESP. There is minimal full-scale sulfuric acid emission data from facilities similar in design to the Holcomb 2-3 project (PRB coal-fired units equipped with SCRs, dry FGDs, and fabric filters) that could be used to adequately define the inlet conditions for a downstream wet ESP.*

*The cost of removing sulfuric acid with a wet ESP installed downstream of the dry FGD and fabric filter, to the extent there is any meaningful removal, would be extremely costly. Staehle, et al.*[26] *presented capital and operating costs estimates for installing a wet ESP that would be integrated with a wet FGD system for a hypothetical 500 MW unit burning high sulfur coal. The capital costs ranged from \$20 to \$40/kW, and annual operating costs (including capital recovery) ranged from \$1.12 to \$2.2 million per year, depending upon whether 1 to 3 fields were selected for the wet ESP design. It is possible that the costs for a "stand-alone" wet ESP (i.e., not installed on top of a wet scrubber), which would be required on Holcomb 2-3, would be higher due to additional ductwork, structural steel, and foundations.*

*Staehle*[27] *indicated the sulfuric acid removal efficiency for this hypothetical plant ranged from 50% to 95%, depending upon the number of fields installed. As noted above, these removal efficiencies, which were developed for a high sulfur coal unit with a wet FGD system, are not representative for Holcomb 2-3. If the annual operating costs presented by Staehle*[28] *are scaled*

[25] *Sierra Club points to the wet ESP installed at Northern States Power/Xcel Energy's Sherbourne County Station as an example of a wet ESP installed on a coal-fired unit using low-sulfur subbituminous coal similar to the Holcomb 2-3 project to control SAM. However, the wet ESP installed at this facility was not installed to control SAM, but rather to control particulate emissions and to resolve high opacity levels.*
[26] *Staehle R. C., Triscori R. J., Kumar K. S., Ross G. and Pasternak E., The Past, Present, and Future of Wet Electrostatic Precipitators in Power Plant Applications, presented at the Combined Power Plant Air Pollutant Control Mega Symposium, May 19-22, 2003.*
[27] *Ibid.*
[28] *Ibid.*

*for the larger Holcomb 2-3 generating units, and if it is unrealistically assumed that removal efficiencies developed by Staehle[29] are applicable for wet ESPs applied to the Holcomb 2-3 units, then the corresponding cost effectiveness would equal approximately $24,000 to $27,000/ton of sulfuric acid removed. If the sulfuric acid removal efficiencies are only half of the values assumed for the hypothetical high sulfur coal facility assumed by Staehle,[30] then the cost effectiveness values would approach $50,000/ton of sulfuric acid removed. Although not required, because the use of a wet ESP downstream of the dry FGD and fabric filter is not a technically feasible option, the economic evaluation illustrates that the cost-effectiveness of this option, even if it were feasible, would not be a cost effective means of further reducing sulfuric acid emissions on Holcomb 2-3.*

*Finally, there are concerns with SAM values lower than 0.004 lb/mmBtu, due to measurement issues. The level of precision and potential for positive bias of the EPA approved test method for SAM (Reference Method 8) is problematic and is discussed in more detail below. The use of Method 8 would likely create significant issues related to measuring emissions to meet performance guarantees.*

*<u>Demonstrating Compliance with SAM BACT Limits:</u> Permit emission limits require continuous compliance over the life of the facility. It is unreasonable to set an emission limit that is below the level of detection of the methods that are required for demonstrating compliance with the permit:*

> *"...the reviewing agency must establish an enforceable emission limit for each subject emission unit at the source and for each pollutant subject to review that is emitted from the source. If technological or economic limitations in the application of a measurement methodology to a particular emission unit would make an emissions limit infeasible, a design, equipment, work practice, operation standard, or combination thereof, may be prescribed." NSR Manual, page B.57*

*EPA Reference Method 8 (Method 8) is the applicable method for compliance demonstration at stationary sources including power plants, despite being developed for sulfuric acid plants and the recognized unreliability and bias for sources such as coal fired power plants.[31] Method 8 was developed specifically for measuring sulfur oxide emissions from sulfuric acid manufacturing plants. These sources have relatively clean and dry emission streams with few or no interferences. Method 8 works very well for these kinds of sources. Because Method 8 is the only method that EPA has published for measuring sulfuric acid/sulfur trioxide emission, it has been applied to many source categories other than the one for which it was developed. However, it may not work very well for some source categories and may not be appropriate for measuring sulfur oxide emissions from them as verified by the following statement:*

> *"It should not be used to measure sulfuric acid/sulfur trioxide from the following kinds of sources: 1. Those sources that have significant emissions of solid sulfates*

[29] *Ibid.*
[30] *Ibid.*
[31] *FAQS section of the EPA website <u>http://www.epa.gov/ttn/emc/methods/method8.html</u>*

*that are water soluble. Solid sulfates are compounds like sodium sulfate. 2. Those sources that have significant emissions of sulfur dioxide and ammonia".*[32]

*Method 8 is applied to coal-fired power plants that certainly meet the second criteria. In addition to the statements on the EPA Technology Transfer webpage, there are technical papers that address this issue. For example, one expert comments with respect to Method 8:*

> *"This method has significant limitations even when applied to sulfuric acid plant gas streams, and is generally not appropriate in a utility boiler application. Perhaps the most important limitation is that a small amount of $SO_2$ is absorbed in the IPA solution, and is oxidized to $SO_3$. The oxidation is thought to be caused by either $O_2$ in the flue gas or trace $H_2O_2$ in the IPA and is catalyzed by trace impurities in the flue gas. Efforts to overcome this deficiency have included the addition of antioxidants which have not been successful. The errors that can be introduced can be equal to or greater than the amount of $SO_3$ present in the flue gas. It is nearly impossible to determine the errors from $SO_2$ measurements, as the loss of a few ppm of $SO_2$ from the flue gas analysis typically represents less than one percent of the total $SO_2$ present, but this is usually a significant amount in proportion to the $SO_3$ content."* [33]

*As noted in the Holcomb PSD Permit Application, test results at the existing Holcomb 1 produced non-detect levels of SAM. Vendors will provide guarantees only down to 0.004 lb/mmBtu due to concerns with the test method and inability to demonstrate that the guarantee has been achieved.*

*Method 8 is reported by EPA to have a minimum detection limit of 0.06 mg/ $m^3$. Using EPA F-Factors, this converts to approximately 0.01 ppm. Background information on the development of the test method indicates that "A collaborative test program was conducted at a sulfuric acid plant to determine the accuracy of Method 8. Six laboratories simultaneously sampled the same stack, using two Method 8 sampling trains per laboratory." The reproducibility (between laboratory precision) of the method was 8.03 mg sulfuric acid/$m^3$. This equates to approximately 1.5 ppm.*

*Establishing SAM BACT Limit: The commenter has cited the SAM emission limits in the recent permits that are below the 0.004 lb/mmBtu limit proposed for Holcomb 2-3.*

*Newmont's actual limit is 2.06 lb/ hour but is converted to the above limit based on heat input. This conversion to lb/mmBtu is dependent on the facility's operating load. The limit will vary as a result of the operating load variations throughout the compliance demonstration, which is a one time performance test. The limit stated in this comment for Parish 8, which is located in Texas, is much lower than more recent BACT determinations for other facilities in Texas, including the eight TXU units (0.0036 lb/mmBtu), Spruce (0.0037), and Sandy Creek (0.0037).*

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[32] *Ibid.*

[33] *Flue Gas $SO_3$ Determination – Importance of Accurate Measurements in Light of Recent SCR Market Growth, Jack Bionda. Prepared for the 2002 Conference on SCR and SNCR Reduction NOx Control, Pittsburgh, PA, May 15 -16, 2002*

*Thus, Parish 8 was not considered in the BACT determination for Holcomb 2-3. Santee Cooper Cross Units 3 and 4 netted out of PSD for SAM along with $NO_x$ and $SO_2$. Therefore, Santee Cooper Cross Units 3 and 4 were not required to conduct a BACT analysis for SAM. Notably, Santee Cooper has proposed two similar units (Pee Dee Units 1 and 2) which propose a substantially higher limit of 0.0075 lb/mmBtu as BACT for SAM. SEI Birchwood also appears to be an anomaly because the facility received its permit in 1993 and numerous permits have been issued since that time with limits comparable to the BACT limit proposed for Holcomb 2-3. AES Puerto Rico is a circulating fluidized bed (CFB) boiler followed by a polishing scrubber intended for $SO_2$ control. This facility is wholly unlike Holcomb 2-3.*

*None of these facilities' limits may be demonstrated or measurable, given the limitations of the measurement methodology discussed above. Newmont, SEI Birch wood, and Santee Cooper Cross were noted in the Holcomb BACT analysis, and, as stated therein (Section 4.0, page 4-77), KDHE unable to document any test data supporting these limits. Among the most recent permits, the majority are at comparable levels or above 0.004 lb/mmBtu.*

*This commenter does not cite any operating data for actual emissions of SAM. There is a considerable literature (some of it cited by Sierra Club) that discusses the possible control efficiency of various technologies for SAM for boilers burning higher sulfur coal and with wet FGD systems. These data are not applicable to the Holcomb 2-3 emission control systems for reasons discussed earlier in this response.*

*In summary, an adequate BACT analysis for SAM was completed that eliminated wet ESP as an add on control options with any FGD, and has properly recommended a BACT emission limit based on both limits established as BACT elsewhere and methods for demonstrating compliance. Thus, the PSD permit established the BACT limit for SAM as 0.004 lb/mmBtu.*

**PM/$PM_{10}$ BACT and Emission Limits (SCC III G)**

**Comment 37:**

The draft permit does not contain proper BACT limits for PM/$PM_{10}$ emissions from the PC boilers. The Developers proposed limits for PM and $PM_{10}$ as 0.012 lb/mmBtu for filterable PM and 0.035 lb/mmBtu for total PM. The draft permit includes a "limit" of 0.012 lb/mmBtu for filterable and 0.018 to 0.035 lb/mmBtu for total $PM_{10}$—both excluding startup and shutdown. While the Draft Permit purports to establish a 0.018 lb/mmBtu limit if initial compliance tests show that such limit can be met, such determination is left only to KDHE, without any assurance that the source will make bona fide efforts to meet 0.018, and with the source having a disincentive to maximize $PM_{10}$ control. There is no opportunity for public comment and input on the future decision of the KDHE to require 0.018 or 0.035 lb/mmBtu as a $PM_{10}$ limit.

***KDHE Response:***

*KDHE has clarified the final permit to include an opportunity for public and EPA peer review for changes in the $PM_{10}$ limit.*

*Permit Condition Structure:* *KDHE has previously addressed the accuracy of EPA approved methods of measurement and the interpretation of test results associated with total $PM_{10}$ emissions. In the course of permitting Sand Sage (predecessor to Holcomb 2), Sunflower provided KDHE with a substantial body of evidence, and that information was included as Appendix K to the current Holcomb 2-4 Application. This information included EPRI data concerning the measurement of $PM/PM_{10}$, the interpretation of testing results, and a summary and discussion of test results at Holcomb 1. These test results indicate that the approved EPA testing method (Reference Method 202) for total $PM_{10}$ does not accurately measure condensable $PM_{10}$ (CPM), but rather overstates the quantity of such substances actually emitted from generating units like those under consideration. In particular, the test apparatus appears to convert a portion of the $SO_2$ in the flue gas into $SO_3$ (the precursor of SAM). A summary is provided in Appendix K (page 7) to the Permit Application:*

> *"The measurements carried at Holcomb 1 demonstrate quite clearly that there is very little $SO_3$/sulfuric acid in the flue gas, and that the $PM_{10}$ levels measured by Method 202 consist primarily of sulfuric acid that is being formed in the test instrument. GE-Mostardi has performed calculations of the amount of sulfuric acid detected in the Method 202 samples compared to the amount of $SO_2$ in the stack (i.e. the amount entering the instrument). These calculations indicate that about 15% of the $SO_2$ in the flue gas is converted into sulfuric acid in the testing process. This quantity is determined not by any inherent characteristic of the flue gas, but simply by the design of the instrument itself. The Method 202 instrument contains cold water through which the flue gas passes for a substantial period. These test results prove that $SO_2$ oxidizes to sulfuric acid under these conditions and is collected in the sample."*

*The particular implication of this phenomenon is that the "measured" result for total $PM_{10}$ using Reference Method 202 will be greater than the actual sum of the parts, including SAM. A further implication of the flaw in the testing method is that the results obtained at other units may not be a reliable predictor of results that would be obtained at Holcomb.*

*EPA has come to recognize the flaws in Method 202, but has not yet approved a replacement or corrected method. EPA is conducting a substantial research program to correct these problems. The following is from the EPA discussion of this test method[34]:*

> *"Does EPA Method 202 provide reproducible results?*
>
> *When conducted consistently and carefully, EPA Method 202 does provide acceptable precision for most emission sources. However, several options are allowed by the method to accommodate State/local test methods that existed at the time the method was proposed and promulgated in the Federal Register. Each of these options may change the mass that would be counted as condensable particulate matter. As a result, when the same source is tested using different options allowed by the method there may appear to be a large variation of the condensable particulate emissions. In addition, the flue gas characteristics may*

[34] http://www.epa.gov/ttnemc01/methods/method202.html

*exacerbate the perception of the amount of variation that is introduced by the optional procedure. For example, under specified conditions, EPA Method 202 allows the one hour nitrogen purge to be replaced with air or not conducted when specified conditions exist. Each of these options results in more $SO_2$ remaining dissolved in the impinger water. The dissolved $SO_2$ slowly converts to $SO_3$ and then to sulfuric acid. While the $SO_2$ should not be counted as condensable particulate matter, both $SO_3$ and sulfuric acid form particulate matter. As a result, EPA Method 202 should not be considered to be a single standardized test method, but should be considered to be a collection of test methods. Therefore, when EPA Method 202 is specified as the applicable test method, any optional procedures should also be specified in order to achieve results that are more in agreement with the basis of the specified emission limitation."*

*Based on concerns about the interpretation of test results and other operating units, KDHE provided for a specific operational testing program in the permit and, if necessary, review of the $PM_{10}$ emission limit. Comments from EPA were received and considered in developing the $PM/PM_{10}$ limits incorporated in the draft permit for H2, H3, and H4. This approach was the subject of an opportunity for public comment when the same limit and process in the permit for testing and possible revision of that limit were proposed and established as part of the earlier Sand Sage permit. The provisions of the draft permit for H2, H3, and H4 dealing with $PM_{10}$ are identical to those in the (now expired) permit issued for Holcomb 2 alone.*

*A similar approach has been adopted in other permits. For example, the proposed permit for the Desert Rock project provides:*

***"T. Permit Revision***

1. *At the end of an 18-month period immediately following initial startup, the Permittee may submit to EPA the performance testing data collected in this period for total $PM_{10}$ for each PC boiler. The performance testing data shall be in raw and reduced or summarized form.*

2. *"If EPA determines from the performance testing data that the PC boilers and associated control devices have not achieved $PM_{10}$ emissions lower than the limits prescribed in X.I., EPA may revise these conditions to reflect the equipment and control devices' performance."*

*Multiple permits have established PM and $PM_{10}$ limits that may be adjusted after a specified period of time. Multiple permits have established a $NO_x$ BACT limit with a provision for an optimization period with an interim higher limit during the optimization period. PSD permits established optimization periods of 36, 18 and 18 months, respectively, for Hawthorn 5A, Whelan, and Nebraska City during which time a higher limit applied. Thus, there is substantial precedent for structuring a permit condition as was proposed for Holcomb 2-3.*

*If the initial performance test under paragraph 2.d. demonstrates that an emission limit at 0.018 lb/mmBtu is consistently achievable, the limit will become operative as a permit condition.*

**$PM/PM_{10}$ BACT and Emission Limits (SCC III G a)**

**Comment 38:**

The $PM_{10}$ averaging time is not BACT. The $PM_{10}$ BACT determination is based on 6 runs of at least 120 minutes. Particulate matter stack testing typically consists of three one-hour tests. Particulate matter BACT determinations are thus normally based on a 3-hour average.

***KDHE Response:***

*The length of the test period is not the same as the length of the averaging period. This commenter draws the incorrect conclusion from the possibility that actual emissions averaged over a longer period might, all other factors being equal, result in a lower average emission rate than could result if emissions were averaged over a shorter time period.*

*For PM emissions, most permits do not specify an averaging period. Compliance with PM emission limits is typically determined by performing three successive 1-hour tests,[35] with a short break between each test. Continuous testing over all three hours is generally not performed. In fact, the testing apparatus does not permit such continuous tests.*

*In contrast, the permit provides for the following:*

- *three (3) runs of at least 120 minutes in duration for tests for filterable PM only using Method 5, and*
- *six (6) runs of 120 minutes in duration for total $PM_{10}$ (filterable and condensable) performed using Methods 5 and 202 (or the identified alternatives).*

*By utilizing this testing methodology, rather than the standard protocol of three successive 1-hour tests, the resulting average $PM_{10}$ emission rate should be more representative of long-term performance than the emission rate that would be determined from the three 1-hour tests averaged together.*

*If the emission limit-setting stack test for the Holcomb units were to be shortened from that established by the permit to the standard three successive 1-hour tests, it is possible that the resulting data would suggest a $PM_{10}$ emission limit lower than that which would be suggested by the data resulting from the test period called for in the permit. On the other hand, it is equally possible that the data resulting from a shorter test period would suggest the necessity for an emission limit that is significantly <u>higher</u> than the one that will be established as the result of the data generated by the test period presently called for.*

*Finally, NSPS Compliance demonstration requirements for this source is found at 40 CFR 60.50Da(b)(2)(i), wherein the minimum sampling requirement of 120-minute per run is identified.*

[35] *The 1-hour tests are generally identified as Method 5 for filterable PM and Method 202 for condensable PM.*

*In short, the argument is misplaced in comparing the concept of averaging time to that of the length of the stack tests. Thus, the permit change suggested could be counterproductive in establishing the lowest possible $PM_{10}$ emission limit.*

**$PM/PM_{10}$ BACT and Emission Limits (SCC III G b)**

**Comment 39:**

The $PM_{10}$ limit is inconsistent with condensable emissions. The application states that Holcomb 2-4 will meet a filterable $PM_{10}$ limit of 0.012 lb/mmBtu. This means that the proposed total $PM_{10}$ limit assumes that condensable particulate matter will be emitted at 0.023 lb/mmBtu. This far exceeds the total emissions of all components of condensable $PM_{10}$. The permitted emission rates for the condensable $PM_{10}$ components, divided by the firing rate of 6,501 mmBtu/hr, are 0.01394 lb/mmBtu. This is a little more than half of what the $PM_{10}$ limit assumes for condensible PM.

Therefore, the actual condensable PM is only a fraction of the 0.023 lb/mmBtu potential condensable constituents.

***KDHE Response:***

*The test method currently required for measurement of total PM is EPA Method 5 (filterable only). The test method currently required for measurement of total $PM_{10}$ is Method 202 (condensable portion) combined with one of the following: Method 5, 201, or 201A (filterable portion). Test results at Holcomb and elsewhere indicate clearly that this method significantly "over-measures" so-called condensable $PM_{10}$ (CPM). For a discussion of this issue, see the PSD Permit Application Appendix K. For the specific issues of measurement of condensable particulate, see KDHE's response to Comment 37. For this reason, the "measured" total $PM_{10}$ may not match the actual sum of the filterable PM and the CPM. Therefore, this commenter's suggested approach to constructing a BACT limit is inappropriate.*

**$PM/PM_{10}$ BACT and Emission Limits (SCC III G c)**

**Comment 40:**

Lower $PM_{10}$ limits are achievable. The BACT analysis proposed a $PM_{10}$ limit of 0.035 lb/mmBtu. There have been a number of recent permits with total $PM_{10}$ limits at and below 0.018 lb/mmBtu. Two examples are the Elm Road Generating Station in Oak Creek, Wisconsin, and the Weston Generating Station Unit 4 in Rothschild, Wisconsin. Both have total $PM_{10}$ limits of 0.018 lb/mmBtu. The Hawthorn plant was permitted with a total $PM_{10}$ BACT limit of 0.018 lb/mmBtu and is meeting that limit. The J.K. Spruce Plant in Texas has a permit limit for total PM of 0.022 lb/mmBtu based on an annual average. Spruce is a 750-MW pulverized coal-fired boiler that will burn PRB sub-bituminous coal similar to the fuel planned for Holcomb. An older permit, for the Council Bluffs Energy Center in Iowa, has a total $PM_{10}$ limit of 0.025 lb/mmBtu, based on a 3-hour average. The Thoroughbred PSD permit has a total $PM_{10}$ limit of 0.018 lb/mmBtu. The Longview plant, in West Virginia, also has a total $PM_{10}$ permit limit of 0.018

lb/mmBtu. This facility will burn coal with up to 3.25% sulfur and 25% ash, which will create more PM before controls than the Holcomb units. Finally, the application for the 750-MW Louisville Gas & Electric Trimble station in Kentucky proposes a total PM/$PM_{10}$ limit of 0.018 lb/mmBtu as BACT. This facility, too, will create more PM before controls than Holcomb.

***KDHE Response:***

*As discussed in Comment 37, there are concerns about the validity of the testing methods employed to determine the emissions from the few operating units that are currently subject to limits on total PM/$PM_{10}$. For that reason, the proposed permit provided a presumptive emission limit at 0.018 lb / mmBtu.*

*Notably, a number of the permits cited in this comment allow for alternate methods of testing for total PM/$PM_{10}$ and/or for revision of the permit limits, depending on issues related to test methods. Specifically, the Weston 4 and Elm Road permits state that the method of compliance testing is Reference Method 202 or an alternate method. Weston 4 also allows for a change to the permit limit if "artifacts are not adequately allowed for in the test methods." For all units permitted in Texas, the method of compliance is a state approved test method that allows for the adjustment of the methodology to address the artifacts issue[36]. The final permit limit for $PM_{10}$ of 0.018 lb/mmBtu is consistent with the emission limits in other permits as identified by this commenter.*

**Comment 41:**

The Northampton Generating Station in Pennsylvania received a permit in April 1995, which includes a total $PM_{10}$ limit of 0.0088 lb/mmBtu, based on an hourly average. Northampton's flue gas properties will be similar to those from Holcomb 2-4. Therefore, Holcomb 2-4 should be able to meet the same or a lower total $PM_{10}$ limit as Northampton. Presumptive BACT for total $PM_{10}$ for Holcomb 2-4 is an emission limit of 0.0088 lb/mmBtu or lower.

***KDHE Response:***

*The Northampton limit is not relevant to the determination of BACT for total $PM_{10}$ for Holcomb 2-3. As confirmed by Pennsylvania Department of Environmental Protection (PADEP), the Northampton permit limit of 0.0088 lb/mmBtu is for total PM, not total $PM_{10}$.*

*In the April 4, 2005 Comments and Response Document for Robinson Power Company, LLC Beech Hollow Power Project,[37] PADEP makes the following statement:*

> *"The Northampton facility limits particulate matter emissions as follows: The concentration of particulate matter [total particulate matter and particulate matter with an aerodynamic diameter of 10 micrometers or less ($PM_{10}$)] in the effluent gases from CFB boiler shall not exceed the following rate:*

[36] *Texas Air Control Board Laboratory Methods Manual*
[37] *Air Quality Permit File: PA-63-00922A*

(1) 0.0088 pounds per million BTU heat input on an hourly average, and

(2) 10.1 pounds per hour, and

(3) 34.7 tons per year.

*Note that this emission limit is for total PM, not total $PM_{10}$. Consequently, compliance with this emission limit has not been determined using filterable and condensable $PM_{10}$ emissions, but rather filterable only."*

*The performance testing information supplied by Sierra Club does not demonstrate compliance with a $PM_{10}$ limit. Sierra Club accurately portrays the numeric results, but those results are for total PM, not total $PM_{10}$. On page 15 of Sierra Club Exhibit LLL, it is clearly stated that the method utilized was EPA Reference Method 5, which excludes condensable particulate. This method is applicable for the determination of total PM emissions, not total $PM_{10}$, from stationary sources.*[38]

**Comment 42:**

Additional performance tests from the State of Florida confirm that the Holcomb units 2-4 can achieve much lower emission rates than proposed as BACT in the draft permit. Similar results have been reported for Georgia Power's coal-fired units. Moreover, U.S. EPA conducted a BACT determination for a plant in Baldwin, Illinois. U.S. EPA's expert concluded that BACT for filterable PM on a plant firing sub-bituminous coal was 0.006 lb/mmBtu, which U.S. EPA determined is achieved with a 2002-vintage baghouse.

***KDHE Response:***

*The Florida testing data identified by this comment indicate that 35% of the measured emissions of filterable particulate matter were at concentrations in the range of 0.015 lb/mmBtu and 0.010 lb/mmBtu. The final permit limit for Holcomb was 0.012 lb/mmBtu. The data suggest that in order to meet this limit a high level of performance in controlling PM emissions will be required at Holcomb 2-3. The final permit limit is consistent with these results, including consideration of the need to establish an emission limit that can be consistently attained.*

*The operational data contained in Sierra Club Exhibit MMM, as noted above, indicates that a final permit emission limit of 0.012 lb/mmBtu as proposed for Holcomb is consistent with operating experience and reasonable considering the necessity to establish an emission limitation that can be consistently achieved by the applicant.*

[38] *http://www.epa.gov/ttn/emc/promgate/m-05.pdf*

**CO and Volatile Organic Chemicals (VOC) BACT and Emission Limits (SCC III H a.)**

**Comment 43:**

KDHE failed to conduct a top-down analysis of BACT for CO, which would have concluded that BACT is lower than the proposed 0.15 lb/mmBtu limit. The permit for Holcomb units 2-4 must include BACT limits for carbon monoxide (CO) and volatile organic compounds (VOC).

***KDHE Response:***

*The application contains a "top-down" BACT for CO. Part 4.0, Section 6.0 of the Holcomb PSD application clearly states that there are no add-on controls available for a facility of this type, that combustion controls are the only remaining technology, and therefore, have been selected as BACT (see page 4-63). In addition, the application included a Review of Potential Control Technologies in Appendix E. Table E-1 identified and eliminated the following technologies:*

- *Regenerative Thermal Oxidation*
- *Recuperative Thermal Oxidation*
- *Flares*
- *Afterburners*
- *Catalytic Oxidation (see Appendix E, Table E-1, page 6 of 7)*

*No database searches identified applications of catalytic oxidation on coal-fired boilers. At the required location in the boiler flue gas (i.e., in the temperature range of 600°F to 1,000°F), there are a number of technical issues concerning the applicability of catalytic oxidation for CO control. The major factors include unacceptably high particulate loadings, elevated trace element concentrations, and high $SO_2$ to $SO_3$ conversion. The statement of basis and fact sheet for the Desert Rock facility indicates that EPA's analysis supports that the only practical or demonstrated in practice measure to control CO from coal-fired boilers is good combustion practices. Sunflower has selected combustion controls as the appropriate control technology for CO, thereby, fulfilling the elements of a "top-down" BACT determination.*

*VOC comments are addressed in the KDHE Response to Comment 44.*

**Comment 44:**

Carbon monoxide emissions are the result of incomplete combustion. An SCR will capture 90% or more of the $NO_x$ from the boiler at most $NO_x$ concentrations exiting the boiler. By maximizing SCR performance, an operator can compensate for slightly higher $NO_x$ rates from the boiler resulting from more complete combustion and CO reduction.

***KDHE Response:***

*This comment would be correct only if combustion controls could be used to shift the CO/VOC vs. $NO_x$ balance to a meaningful extent. Boilers are designed with multiple objectives in mind,* *including thermal efficiency (which is degraded significantly if extraordinary amounts of excess combustion air are used), reliability of operation (e.g., minimizing the effects of tube-wall corrosion), and overall flame stability. No one has ever designed and tested a boiler configuration and controls specifically intended to produce a lower CO/VOC level. No operating data or technical source has been cited to indicate that this is possible. This comment is purely speculative in the context of a top-down BACT analysis.*

*As noted in this comment, "reducing CO emissions results in an increase of $NO_x$ production in the boiler." Thus, the commenter acknowledges the commonly understood relationship between the formation of $NO_x$, CO, and VOC in coal fired boilers. This was discussed separately in the respective sections of Part 4 of the Holcomb PSD application.[39] However, this commenter attempts to separate the pollutants or suggest theoretical approaches to reducing the emission limits for all three pollutants individually. Such approach is counter to the combustion process. Instead $NO_x$, CO, and VOC are dependent variables and therefore are affected simultaneously.*

*Accordingly, KDHE has approached the selection of the BACT emission limits for these three pollutants in a holistic fashion, recognizing the interrelationships in the formation, relative level of concern, and impact of each. Achieving CO emission reductions at the expense of increasing $NO_x$ emission levels is generally not encouraged. Simultaneously balancing low CO and $NO_x$ emission levels at the steam generator outlet is an appropriate consideration in the steam generator design and operation. Ultimately these factors need to be considered when selecting a BACT emission limit as well. It is inappropriate to simply look at one pollutant at any particular facility without considering the emission limits of the other two pollutants.*

*$NO_x$ Limit: As a result of ongoing review of new permit developments, operating data and technical information, the permit includes a 0.05 lb/mmBtu on a 30-day rolling average basis as BACT for $NO_x$. A full discussion of the $NO_x$ BACT is provided in KDHE's response to Comment 52 on that topic. The following discussion addresses the reason for maintaining CO and VOC BACT emission limits as originally proposed in light of the revised $NO_x$ limit.*

*Interrelationship of $NO_x$, CO, and VOC[40]: As briefly described below, the establishing ideal combustion conditions which result in decreasing $NO_x$ emissions is to simultaneously establish combustion conditions that actually increase CO and VOC emissions. Recent burner improvements that enable lower $NO_x$ emission levels at the furnace outlet are achieved by designing for rich fuel-air mixtures in the primary combustion zones of the individual burners. Increased CO levels at the furnace outlet are the result.*

*$NO_x$ is primarily formed in combustion processes in two ways: 1) the combination of elemental nitrogen with oxygen in the combustion air within the high temperature environment of the burner (thermal $NO_x$); and 2) the oxidation of nitrogen contained in the fuel (fuel $NO_x$). Minimizing the formation of $NO_x$ includes reducing flame temperature, controlling the fuel to air ratio, and reducing oxygen availability in the initial combustion zone. Altering combustion conditions imposes tradeoffs between reducing $NO_x$ and increasing creation of CO and VOC,*

*[39] Holcomb 2-4 PSD Application pages, 4-18, 4-19, 4-63, 4-64, 4-66 and 4-69*
*[40] Discussion based on material found in Holcomb 2-4 PSD application Part 4.0*

*and also must be carefully tailored to avoid damage to the steam generator walls and other surfaces.*

*CO is a product of incomplete combustion (PIC). The formation of CO results when there is insufficient residence time at high temperature or incomplete mixing to complete the final step in fuel carbon oxidation. Similarly, VOC is considered a PIC, and the formation is directly proportional to the overall combustion efficiency of the source. PIC emissions are controlled through managed combustion practices, including high temperatures, adequate excess air and residence time, and optimal fuel/air mixing during combustion. It is not possible to minimize these emissions without increases in emissions of $NO_x$. The most effective way of controlling CO and VOC emissions is to allow for adequate residence time in the combustion chamber, sufficient temperature to complete the reaction, and thorough mixing of the fuel and air.*

*-Relative level of concern and impact[41]:* *As noted above, $NO_x$ emissions from coal fired boilers are typically of greater concern to regulators. Utilities account for roughly one quarter of all $NO_x$ emitted in the US, and 90% of that comes from coal fired boilers. In contrast, CO emissions from utility boilers are a relatively small percentage of total US combustion sources. The majority of the CO emissions come from internal combustion engines in the transportation sector. Similarly, the major source of VOC emissions is transportation and the commercial/residential combustion sectors. To put this in perspective, $NO_x$ emissions from utility combustion in 2002 made up 22% of the total US anthropogenic emissions whereas VOC made up only 0.31%.[42]*

*Availability of Control Technology and Technical concerns: The lowest $NO_x$ emission levels for a pulverized coal unit are achieved by the use of SCR technology combined with combustion control methods (i.e., LNB and SOFA) to achieve the greatest overall reduction. CO and VOC formation can be reduced by utilizing good combustion practices to minimize their formation in the steam generators. There are no add-on control technologies available for application to coal-fired steam generators for direct CO and VOC control.*

*For any operator, the objective is to have an efficient combustion process, fully oxidize the carbon in coal, and not have CO, regardless of the coal type. However, all coals are different, and each coal has unique characteristics that must be accounted for in the equipment design and operation. An issue common to PRB coal is the concern with the slagging of PRB ash. That is, PRB-fired boilers are designed to have somewhat lower boiler exit temperatures to avoid slagging problems associated with the low fusion temperature PRB ash. Lower boiler exit temperatures would encourage somewhat higher CO concentrations in the flue gas.*

**Comment 45:**

There are a number of post-combustion controls available to reduce carbon monoxide emissions from the boilers at Holcomb 2-4. These options include:

i. Thermal Oxidation capable of achieving 95% reduction;

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*[41] Discussion is based on material found in "Steam: Its Generation and Use, 41st Edition, Copyright 2005. Chapters 32, 34*
*[42] Ibid., Chapter 32, Table 6*

ii. Catalytic Oxidation capable of achieving 85% reduction; and

iii. A combination of proper boiler design and good combustion practices.

Thermal oxidation is an available pollution control technology. At least one Portland cement kiln, in Midlothian, Texas, uses thermal oxidation to control CO emissions.

Therefore, thermal oxidation is an available control technology that must be considered in a top-down BACT analysis. Thermal oxidation will achieve greater reductions of CO (and VOC) from Holcomb and must be used to establish BACT limits unless the Developers adequately demonstrate that adverse energy, environmental, and economic impacts are documented.

***KDHE Response:***

*The permit application included potential emission control technologies for Holcomb 2-3 as Step 1 of a "top-down" process for each of the applicable BACT pollutants. The information concerning the technologies evaluated was included in Appendix E of the air permit application. This review initially considered emission control technologies, regardless of emitting source type. As shown in Appendix E, thermal oxidation (or thermal incineration) and catalytic oxidation were both initially considered for CO and VOC. However, these technology options were dropped from further consideration, as they are not applicable to coal-fired boilers. One of the reasons these technologies were eliminated is that the database searches and permit reviews did not identify a single application of this technology to coal-fired boilers. However, other factors also played a part in their eventual elimination.*

*TXI Operations, LP (TXI) operates a Regenerative Thermal Oxidizer (RTO) system at its Midlothian, Texas facility. TXI elected to install the RTO in order to "net out" of a PSD review for the project; that decision was not based on a determination by the State of Texas that the RTO was a necessary element of BACT for CO or VOC. After operating the plant for about one year, TXI approached the Texas Commission on Environmental Quality (TCEQ) and requested that it be allowed to discontinue the operation of the RTO. The request was based on an alleged inferior design of the RTO, high operating cost due to sharp increases in the price of natural gas used to operate the RTO, and an excessively high pressure drop across the RTO. In evaluating this request, TCEQ determined that the RTO was technically feasible but economically unreasonable and did not constitute BACT for CO or VOC. Even though TCEQ agreed with TXI that the RTO was not BACT, TXI agreed in a settlement agreement with petitioners to continue to operate the RTO, but at a reduced temperature.*

*As stated previously, there is no direct experience for coal-fired boilers using thermal oxidation for control of CO or VOCs. TXI's experience using RTO for controlling CO and VOC emissions from its No. 5 Kiln has resulted in various operating issues (e.g., high back pressures, high operating costs due to supplemental natural gas firing, and production curtailment for RTO maintenance). Extrapolation of this limited, and less than successful, RTO experience at TXI's Midlothian facility to utility coal-fired boilers would create unacceptable economic and technical risks for development of coal-fired boiler projects. There are differences between the design and operation of coal-fired boilers and the design and operation of kilns at Portland* *cement plants, which affect the practicality of "technology transfer" of RTO systems.*[43] *Specifically, CO and VOC emissions are much higher from cement kilns than from coal fired boilers and, the scale of the equipment is much smaller at a cement kiln. Even if applicable, the energy demands for such a system are unreasonable. All of these issues are discussed below in more detail.*

*<u>CO and VOC Emission Levels</u>: CO and VOC emissions from coal-fired boilers are low due to the high temperatures, excess air levels, and turbulence within the furnace. In Portland cement plants, CO and VOC emissions can result from two sources: the combustion processes in the kiln and oxidation of carbonaceous material in the raw feed introduced to the preheater. It is the second source of CO and VOC emissions that distinguishes the kiln from the coal-fired boiler, creating a significant difference between the two processes. CO and VOC are emitted in the preheater tower where gradual heating volatilizes a portion of the carbon in the raw material at temperatures below that at which complete combustion can occur. These CO and VOC emissions are added to the kiln exhaust just before it exits the kiln/calciner/preheater system. Cemex, in a report in support of a PSD construction permit review, indicated that the CO at the back end of the kilns at its Brooksville, Florida facility is generally maintained below 2,000 ppm.*[44] *The final CO BACT rate for the new steam generators at Holcomb is on the order of 140 ppmvd (ppm volume dry) at 7%* $O_2$*. The final VOC BACT rate for the new boilers at Holcomb 2-3 is on the order of 2 ppmvd as propane at 7%* $O_2$*. The inlet hydrocarbon emissions for the RTO installed at TXI's Midlothian facility were tested at approximately 38 ppmvw (ppm volume wet) at 14%* $O_2$ *(~94 ppmvd at 7%* $O_2$*). Therefore the uncontrolled CO and VOC emissions from Portland cement plants are significantly higher than the proposed BACT CO and VOC emission rates for Holcomb 2-3.*

*The EPA Air Pollution Control Technology Fact Sheet for Regenerative Incinerators, which includes RTOs, indicates that regenerative incinerators can and have been used effectively at inlet loadings as low as 100 ppmv or less. The proposed BACT VOC emission rate for Holcomb 2-3 is significantly below this lower operating range.*

*This comment asserts that "Thermal oxidation routinely removes 90% of the CO (98% of the VOC) from gas streams similar to those from Holcomb 2-3." A thorough review of available information was conducted and no instance of a gas stream similar in makeup to Holcomb 2-3 was found that utilizes a thermal oxidizer.*

*<u>Size of RTO Equipment</u>: Based on information provided by the TCEQ, it appears the inlet flue gas flow rate to the TXI RTO system is on the order of 570,000 scfm. The flue gas flow rate downstream of the SDA/FF systems at each of the proposed Holcomb coal-fired boilers is greater than 1,430,000 scfm. This scale-up of over 2 ½ times the size of the TXI facility (believed to be one of the largest RTOs in service) represents a significant and unacceptable technical risk, especially when applied to a new process category. The TXI RTO system is reported to have eleven cells (or modules) with the intent it would operate on 9 cells, with one on standby and one being cleaned or otherwise maintained. Due to back pressures higher than design, TXI*

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*[43] For many of the same reasons, RTO technology use at ethanol plants, refineries and other sources does not provide sufficient operating experience to be applied to coal-fired power plants.*
*[44] Report in Support of an Application for a PSD Construction Permit Review, CEMEX Cement, Inc., October 27, 2005.*

*is reported to operate 11 RTO modules most of the time, instead of the design 9, to minimize back pressure. With 11 modules operating, the average RTO back pressure was 22.0 inches of water. The higher flue gas volumes associated with each of the new Holcomb coal-fired boilers is expected to result in an unacceptable level of mechanical complexity and maintenance demand for moving parts if an RTO system were installed on these boilers.*

*The EPA Air Pollution Control Technology Fact Sheet for Regenerative Incinerators, which includes RTOs, indicates that typical gas flow rates for regenerative incinerators are 5,000 to 500,000 scfm. The flue gas flow rates for each of the new Holcomb boilers are significantly above this upper gas flow rate.*

*<u>High Energy Demands of RTO and Increased Air Emissions</u>: The installation of RTO systems on each of the new coal-fired steam generators at Holcomb would require significant increases in energy requirements due to the higher fan power requirements as well as natural gas consumption for thermal oxidation of CO and VOC. Due to the higher auxiliary electrical load, increased coal-firing would be required to maintain the same net electrical output of the new Holcomb generating units without an RTO system. This would essentially increase all air emissions from each of the coal-fired steam generators, in order to attain marginal reductions in CO and VOC. The natural gas burners used in the RTO system could also increase emissions of* $NO_x$.

**Comment 46:**

Even if the lowest ranked pollution control option, combustion practices, is used, 0.15 lb/mmBtu does not represent BACT. A number of plants have permitted CO BACT limits lower than the 0.15 lb/mmBtu proposed for the Holcomb units, as shown in Table 10.

**TABLE 10. CO BACT LIMITS IN OTHER PERMITS (FROM SIERRA COMMENTS)**

| Facility | Size/Name of Unit | Emission Rate for Coal | Permit Date |
|---|---|---|---|
| Louisiana Generating LLC | 675MW Big Cajun II Unit 4 | 0.135 lb/MMBtu annual avg. | Aug. 2005 |
| PSC Colorado | 750MW Comanche Unit 3 | 0.13 lb/MMBtu 8-hour avg. | July 2005 |
| Montana Dakota Utilities | 220MW Gascoyne Greenfield | 0.154 lb/MMBtu 3-hour avg. | June 2005 |
| Newmont Nevada | 200MW TS Plant Greenfield | 0.15 lb/MMBtu 24-hour rolling | May 2005 |
| Omaha Public Power | 660MW Nebraska City Unit 2 | 0.16 lb/MMBtu 3-hour rolling | March 2005 |
| Wisconsin Public Service | 500MW Weston Greenfield | 0.15 lb/MMBtu 24-hour avg. | October 2004 |
| Utah Intermountain PSC | 950MW Intermountain Unit 3 | 0.15 lb/MMBtu 30-day rolling | October 2004 |
| West Virginia Longview | 600MW Monongahela Greenfield | 0.11 lb/MMBtu 3-hour rolling | March 2004 |
| S. Carolina Santee Cooper | 570MW Cross Units 2 and 3 | 0.16 lb/MMBtu | February 2004 |
| Arkansas Plum Point | 800MW Greenfield Unit 1 | 0.16 lb/MMBtu | August 2003 |
| Iowa MidAmerican | 765MW MidAmerican Greenfield | 0.154 lb/MMBtu 24-hour avg. | June 2003 |
| Kentucky Thoroughbred | 750MW Greenfield Units 1 and 2 | 0.10 lb/MMBtu 30-day rolling | October 2002 |
| Kansas Sand Sage | 660MW Holcomb Unit 2 | 0.15 lb/MMBtu | October 2002 |
| Wyoming Black Hills | 500MW Wygen Unit 2 | 0.15 lb/MMBtu | Sept. 2002 |
| Pa. AES Beaver Valley | 215MW Greenfield | 0.20 lb/MMBtu | Nov. 2001 |

Source: *Technical Evaluation and Preliminary Determination for Seminole Generating Station Unit 3*, p. 14. The proposed permit issued by U.S. EPA for the Desert Rock facility contains the following proposed CO limits:

1. 680 lb/hr, averaged over a 3-hour period;

2. 0.10 lb/mmBtu, averaged over a 24-hour period;

3. 631 lb/hr, averaged over a rolling 365-day period.

***KDHE Response:***

*A review of the CO limits in recent permits was conducted. The CO limits (for various averaging periods) in those permits range from a low of 0.10 lb/mmBtu 24-hour average in the proposed permit for the Desert Rock project to a number of permits with limits equal to or higher than the 0.15 lb/mmBtu in the proposed Holcomb permit. The averaging periods contained in these permits range from 24 hours to 365 days. In every case, the proposed technology for control CO emission is combustion controls. No case has been found that selects add-on technology for CO.*

*For a "holistic" comparison of BACT limits, the following table of $NO_x$, CO, and VOC limits was prepared using all of those facilities cited, plus the final Hugo Unit 2 PSD permit.*

***TABLE 11. $NO_x$, CO AND VOC LIMITS IN HOLCOMB AND OTHER PERMITS***

| ***Project*** | ***$NO_x$ Limit*** *(lb/mmBtu)* | ***CO Limit*** *(lb/mmBtu)* | ***VOC Limit*** *(lb/mmBtu)* | ***Permit status*** | ***Fuel / Source Design / Size*** |
|---|---|---|---|---|---|
| ***Holcomb Units 2 & 3*** | ***0.05 (30 day)*** | ***0.15 (30 day)*** | ***0.0035*** | ***Permit 2007*** | ***PRB/SC PC/ 2@ 700 MW*** |
| *Roundup* | *0.07 (annual)*<br>*0.07 (24 hr)*<br>*0.10 (1 hour)* | *0.15* | *0.0030* | *Permit 2004* | *PRB / PC / 2 @ 390 MW* |
| *Springerville Units 3 & 4* | *$NO_x$ CAP* | *0.15* | *0.0033* | *Permit 2002* | *PRB / PC / 2 @ 750 MW* |
| *Council Bluffs* | *0.07 (30 day)* | *0.154 (cal day)* | *0.0036* | *Permit 2002* | *PRB / PC / 900 MW* |
| *Thoroughbred* | *0.08 (30 day)* | *0.10 (30 day)* | *0.0072* | *Permit 2002* | *Bit. / PC / 2 @ 750 MW* |
| *Comanche Unit 3* | *0.080 (30 day)* | *0.13 (8 hr)*<br>*0.30 (startup)* | *0.0035* | *Permit 2005* | *PRB/ PC / 750 MW* |
| *Big Cajun II, Unit 4* | *0.07 (30 day)* | *0.135* | *0.0034* | *Permit 2005* | *PRB / PC / 675 MW* |
| *Gascoyne* | *0.09 (30 day)* | *0.154 (3 hr)* | *0.005* | *Permit 2005* | *Lignite / CFB / 2 @ 220 MW* |
| *Longview* | *0.07 (30 day)* | *0.11 (3 hr)* | *0.004* | *Permit 2004* | *Bit. / PC / 600 MW* |
| *IPP Unit 3* | *0.07* | *0.15* | *0.0027* | *Permit 2004* | *Bit and sub Bit blend / PC / 950 MW* |
| *Weston 4* | *0.06 (30 day)* | *0.15* | *0.0036* | *Permit 2004* | *PRB / PC / 600 MW* |

| ***Project*** | ***$NO_x$ Limit*** *(lb/mmBtu)* | ***CO Limit*** *(lb/mmBtu)* | ***VOC Limit*** *(lb/mmBtu)* | ***Permit status*** | ***Fuel / Source Design / Size*** |
|---|---|---|---|---|---|
| *Newmont* | *0.067 (24 hour)* | *0.15* | *0.004* | *Permit 2005* | *PRB / PC / 200MW* |
| *Trimble* | *4.17 tons/day (0.05)* | *0.10* | *0.0036* | *Permit 2006* | *Bit / SCPC / 750 MW* |
| *Hugo Unit 2* | *0.07 (30 day) 0.05 (annual)* | *0.15* | *0.0036* | *Permit 2007* | *PRB/ PC / 750 MW* |
| *JK Spruce* | *0.069 (30 day) 0.05 (12 month)* | *0.15* | *0.0036 (1 hr) 0.0025 (annual)* | *Permit 2006* | *PRB / PC / 750 MW* |
| *Desert Rock* | *0.060 (24 hour)* | *0.10* | *0.003* | *Proposed Permit* | *Sub bit/ PC / 2 @ 750 MW* |
| *TXU Standard Plant (8 units)* | *0.07 (30 day) 0.05 (12 month)* | *0.15* | *0.0036* | *Proposed permits (on hold)* | *PRB / SCPC / 860 MW each unit* |

*In determining BACT for $NO_x$, CO and VOC, the interrelationships among the three pollutants must be considered. Controlling $NO_x$ is the higher priority. That being said, the following analysis considers the CO limits in terms of the facilities with $NO_x$ limits cited by the commenter in addition to those cited above for low CO limits.*

*This commenter cites only Desert Rock as an example of a lower CO Limit and points to the following permits as examples of low limits when commenting on the $NO_x$ limit proposed for Holcomb 2-3: Newmont, Trimble, JK Spruce, Desert Rock, and the eight TXU units.*

*Desert Rock is not final. Therefore this is not a basis on which to make a BACT determination. With the exception of Trimble and Desert Rock, all of these units establish BACT for CO as 0.15 lb/mmBtu as does Holcomb. Trimble's emission limit is expressed in terms of tons/day not lb/mmBtu. The 0.05 lb/mmBtu limit cited in the comment is calculated from the heat input at full load. At lower loads the limit would actually be higher; for example, at half load the limit would be 0.10 lb/mmBtu. Additionally Trimble utilizes high-sulfur bituminous coal and because of this regional difference and differences in operating practices it can be eliminated from consideration. (See discussion in Response to Comment 44 regarding PRB ash slagging concern.)*

*Based on a review of recent permits and the newly proposed $NO_x$ limit of 0.05 lb/mmBtu, the emission limit for CO in the Holcomb permit remains 0.15 lb/mmBtu. However the average period has been changed to a thirty-day rolling average, including periods of startup and shutdown.*

*This permit requires installation and utilization of a continuous emission monitor for demonstrating compliance with CO emission limitations. The averaging period considers the hour-to-hour and day-to-day variability in CO emissions which have been observed at Holcomb 1. CO emissions are affected by the operation of individual coal burners and the coal pulverizer system. The settings for these burners are manually controlled. When upset conditions occur, resulting in higher-than-normal levels of CO emissions, operators must identify the sources of the problem by inspection of the burners and steam generator and make trial adjustments to the* *burners, a process that may take a day or more to complete. As a result, it is appropriate to allow an averaging time which provides for the necessary operator response time to identify and correct operating problems that result in increased CO emissions. A 30-day averaging period is expected to be adequate for this purpose. This limit will also take into account periods of startup and shutdown, thereby assuring that BACT applies during all operational periods required by PSD regulations.*

*Recent decisions have clarified that BACT limits must include numeric limits when measurable instead of work practice standards.[45] As noted above the permit requires installation of a CEM so that emission rates during startup and shutdown are measurable (except when the concentration of diluent gas is also very low due to firing gas only). Therefore, the permit language includes startup and shutdown periods.*

**CO and VOC BACT and Emission Limits (SCC III H b)**

**Comment 47**:

KDHE failed to conduct a top-down analysis of BACT for VOC, which would have concluded that BACT is lower than the proposed 0.0035 lb/mmBtu limit. Like the BACT analysis for CO, KDHE's BACT analysis for VOC was incomplete. This control option must be considered in a top-down BACT analysis.

***KDHE Response:***

*As previously discussed, potential emission control technologies were reviewed for Holcomb 2-3 as Step 1 of a "top-down" process for each of the applicable BACT pollutants. This review initially considered emission control technologies, regardless of emitting source type. Part 4.0, Section 7.0 of the Holcomb PSD permit application clearly states that there are no add-on controls available for a facility of this type and that combustion controls are the only remaining technology and therefore have been selected as BACT (see page 4-68). In addition the permit application included a Review of Potential Control Technologies in Appendix E. Table E-1 identified and eliminated the following technologies:*

- *Thermal Incineration*
- *Catalytic Incineration*
- *Cryogenic Condensation*
- *Condensation*
- *Carbon Absorption*
- *Polyad[tm] System*
- *Flares*
- *ESP*
- *Rotary Concentrator*
- *Biofiltration*
- *Membrane Technology*

[45] *EAB Order Denying Review in Part and Remanding in Part, Indeck-Elwood, LLC PSD Appeal No 03-04*

- *Ultra violet Oxidation*
- *Plasma Technology*
- *Low VOC Materials*
- *Catalytic Oxidation. (see Appendix E, Table E-1, page 5 of 7)*

*For the same reasons identified in the CO BACT analysis and further expounded upon in the above response, Sunflower appropriately selected combustion controls as BACT for VOC.*

**Comment 48:**

The VOC BACT limit must be lower than the 0.0035 lb/mmBtu limit proposed in the draft permit. A number of previously issued permits contain lower limit. These include Bull Mountain, MT (0.0030 lb/mmBtu) and Springerville, AZ (0.0033 lb/mmBtu), both of which are similar to Holcomb 2-4 and will fire similar fuel. Additionally, the draft permit issued by U.S. EPA for the Desert Rock facility in Arizona includes the following VOC BACT limits:

1. 20.4 lb/hr, averaged over a 3-hour period.

2. 0.0030 lb/mmBtu averaged over a 24-hour period.

The BACT limits for Holcomb must be established at or below 0.0030 lb/mmBtu on a 24-hour basis.

***KDHE Response:***

*As with CO, a "holistic"approach has been taken to evaluate the VOC emission limit for Holcomb 2-3. That being said, the following analysis considers the VOC limit in terms of the facilities with $NO_x$ limits cited by this commenter in addition to those cited above for low VOC limits. Limits for these facilities are presented in Table 11 included in the Response to Comment 46.*

*The commenter cites Bull Mountain (Roundup), Springerville, and Desert Rock as examples of a lower VOC limit and points to the following permits as examples of low limits when commenting on the $NO_x$ limit proposed for Holcomb 2-4: Newmont, Trimble, JK Spruce, Desert Rock, and the eight TXU units. With the exception of Roundup, Springerville, and Desert Rock, all of these units establish BACT for VOC higher than the 0.0035 lb/mmBtu proposed for Holcomb.*

*Roundup has a $NO_x$ limit of 0.07 lb/mmBtu on both a 24-hour and an annual basis. One can assume that the 30 day rolling average for Roundup would not be different or lower than the 24-hour limit, so Roundup is less stringent than final limit for Holcomb 2-3 of 0.05 lb/mmBtu on a 30-day rolling average basis. Therefore, Roundup will be able to achieve lower VOC emissions without exceeding the $NO_x$ emission limit. Permit conditions for Holcomb 2-3 will not allow the same flexibility.*

*Springerville netted out of PSD for $NO_x$, and the permit has established a $NO_x$ cap to enforce this approach. Springerville is limited to 6300 tons per year for the existing Units 1 and 2. When* *either of the new units is operational, the cap is increased to 7947 tons per year. The increased $NO_x$ emissions are 1647 tons per year, which using the heat input of 4200 mmBtu/hour, is converted to an effective emission limit for the new units of 0.097 lb/mmBtu. Once again, taking the holistic approach, Springerville has the ability to achieve a lower VOC limit than Holcomb because the $NO_x$ limit is substantially higher than that in the final permit for Holcomb 2-3.*

*Desert Rock is not final. Therefore, this is not a basis on which to make a BACT determination. Even so, Desert Rock has a higher $NO_x$ limit than Holcomb and therefore will be able to achieve a lower VOC emission rate.*

*The emission limits contained in these recent permits and the holistic approach to setting $NO_x$, CO, and VOC, demonstrate that the limit of 0.0035 lb/mmBtu for VOC is BACT.*

**BACT Limits (SCC III I)**

**Comment 49:**

The BACT limits should be expressed by energy output. BACT must consider efficiency of a unit and total pollution emissions, rather than merely focusing on emissions per unit of energy input. In other words, increased efficiency is a method of pollution control because it decreases the total amount of pollution emitted into the environment to produce electric power.

***KDHE Response:***

*The information provided in Table 4-4 of the application states all limits in terms of lb/mmBtu, as well as a conversion for only $NO_x$ and $SO_2$ in terms of lb/MWh in parentheses. Because the NSPS limit for $NO_x$ and $SO_2$ are now expressed in terms of lb/MWh in 40 CFR 60, Subpart Da, this expression was provided to illustrate that the proposed BACT limits (in terms of lb/mmBtu) are substantially lower than the NSPS. Thus compliance with the BACT limits would also be compliance with the applicable NSPS.*

*Output-based limits are not necessary or practical in determination of BACT for this permit. There are multiple incentives toward efficiency of operation, including the obvious objectives of reducing costs of fuel, lime, $SO_2$ allowances, ammonia, and other cost components that are related to the energy input into the steam generator. Sunflower has chosen a supercritical design for the steam generator, which is specifically intended to promote thermally-efficient power production. The imposition of lb/MWh limits would be redundant, as the final permit contains sufficient limits to ensure that the units are operated efficiently.*

*BACT is determined through the top-down process by analysis of available control technologies and the technologies and emission limits contained in other permits. With the exception of those few NSPS-related limits that are expressed in emissions per MWh, all BACT and other emission limits in other permits are expressed in terms of lb/mmBtu or lb/hour. It would be impossible to make a comparison and determination of BACT for Holcomb with these other permits if the limits for Holcomb were expressed in lb/MWh.*

*Finally, it is unclear what standard of thermal efficiency ought to be applied if emission limits expressed in lb/mmBtu were to be converted into lb/MWh. For example, the thermal efficiency of a steam generating unit varies according to a number of factors, including the ambient temperature, the unit output, and the moisture content of the fuel burned.*

**BACT for Cooling Towers (SCC III J a)**

**Comment 50:**

The BACT analysis and BACT limit for PM emissions from the cooling towers are incomplete. The particulate matter emissions from Holcomb 2-4's cooling towers are subject to BACT. The draft permit requires the Developers install "high efficiency drift eliminators with a maximum total liquid drift not to exceed 0.0005 percent of circulating water flow rate." This is not BACT for two reasons. First, high efficiency drift eliminators are not the top-ranked pollution control option. Second, a drift rate does not constitute a PM limit. The permit must limit PM emissions, which depends on circulating water rate and the concentration dissolved solids in the circulating water. Air Cooled Condenser ("ACC") is a superior option that has no water demand and has much lower PM emissions.

***KDHE Response:***

*Air cooled condensers (ACC) are not comparable to a wet cooling tower and therefore are not considered the "top" technology in the BACT determinations for PM emissions. BACT for a cooling tower is the high-efficiency drift eliminator as is required by the final permit.*

*The commenter makes the claim on the basis of the alleged comparability of heat rate penalties, lower PM emissions, and reduced water use. The following addresses each of those points.*

*<u>ACC and Wet Cooling Tower Comparability:</u> The assertion that the heat rate (power generation thermal efficiency) penalty from an ACC is only 2 percent annually and that this is "comparable" to a wet cooling tower is inaccurate. The source cited for this estimate is a theoretical "desk study[46]". Even if a 2% difference in heat rate is "comparable," this understated difference is sufficient to overwhelm any emissions advantage of a dry cooling system.*

*In December 2001, EPA published final regulations pertaining to cooling water intake structures at new facilities under 316(b) of the Clean Water Act. The Technical Development Document (TDD) for the final regulations addressed energy penalties associated with various power plant cooling options, including ACC and wet cooling towers. The TDD reported average annual energy penalties for various site locations. The incremental energy requirement for operating an ACC versus wet cooling varied from 5.4 to 10.8 percent, depending upon site location. EPA concluded that the cost of dry cooling is more than three times the cost of wet cooling. The*

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*[46] "Peak and Annual Average Energy Efficiency Penalty of Optimized Air-Cooled Condenser on 515 MW Fossil Fuel-Fired Utility Boiler" Author: Bill Powers, P.E., Powers Engineering Technical Reviewer: Dr. John Maulbetsch. The paper notes at page 3: "Steam Pro™ and Steam Master™ utility boiler design software are used to carry out the comparative heat rate analysis of the wet tower base case and ACC alternatives."*

*capital costs for construction and the operating costs are significantly higher for ACC than the comparative cost for wet cooling systems. As a result of its study*[47]*, EPA concluded that dry cooling does not represent the "best technology available" for minimizing adverse environmental impacts.*

*A comparison of heat rejection systems was performed by Black & Veatch for Tri-State's Colorado Power Project,*[48] *a 656 MW super-critical pulverized coal unit located in Colorado, i.e., project size and design similar to Holcomb 2-3. The study assumed two locations, Las Animas, CO and Holly, CO, which are approximately 130 miles and 65 miles, respectively, from Holcomb at roughly the same latitude. Therefore ambient conditions at Holcomb are comparable to these two locations. The assumptions as well as the conclusions would be similar if Sunflower were to undertake a similar evaluation.*[49]

*Based on the Black and Veatch analysis, the heat rate penalty for ACC is greater than 2%. The ACC option had approximately 6.0% higher average-day and 6.4% higher hot-day heat rate than wet cooling towers. The analysis indicates that the incremental annual cost of a dry cooling tower as compared to a wet system would be approximately $5.4 million / year (in 2005 dollars for each approximately 700 MW generating unit). Annual cost includes fixed O&M, variable O&M, fuel cost, water rights cost, pipeline cost, and annual capital cost. As noted below, the maximum potential reduction in PM emissions from use of a dry cooling system compared to a wet cooling system would be approximately 22.4 tons / year. Thus, if ACC were required as a control measure for PM, the cost per ton would be approximately $241,000 per ton removed.*

*The only large scale coal-fired utility unit in the U.S. to use an ACC is the 330 MW Wyodak plant. This facility started operations approximately 25 years ago. Using data from EPA, the annual gross heat rate (Btu/$kWh_{gross}$) in 2005 was approximately 16 percent higher at Wyodak than at Holcomb Unit 1, a similar unit using similar coals. Although the differences in gross heat rate can also include factors other than the method of plant cooling, and both the ACC and wet cooling tower technologies at these plants are approximately 25 years old, the differences in heat rate for these similar units illustrates the lower efficiencies at plants utilizing ACC.*

*<u>PM Emissions:</u> In order for Holcomb 2-3 to deliver the same net electrical output as the current design, which incorporates wet cooling towers, higher fuel consumption would be required if an ACC were to be integrated in the design. The proposed project is sized in relation to the power needs of the participants, so the output cannot be arbitrarily reduced. The higher fuel consumption would result in higher air emissions from each of the steam generators. Table 12 illustrates the estimated increase in tons per year of the PSD pollutants from a single steam generator (excluding PM/$PM_{10}$ emissions from the cooling tower itself, but also from other sources such as material handling which also would increase in proportion to fuel consumption) at Holcomb 2-3 for various assumptions concerning the incremental energy consumption due to the use of an ACC.*

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[47] *Clean Water Act § 316(b) rulemaking. 66 Fed. Reg. 65256, 65282 (Dec. 18, 2001).*
[48] *Black & Veatch Corporation, Colorado Power Project Heat Rejection System Analysis for Tri-State Generation And Transmission Association, Inc., January 2005*
[49] *Hot day and average day temperatures and humidity are similar.*

***TABLE 12. INCREMENTAL AIR EMISSIONS DUE TO INCREMENTAL HEAT RATE INCREASES (ACC VERSUS WET COOLING TOWERS) FOR A SINGLE STEAM GENERATOR AT HOLCOMB 2-3***

| ***Pollutant*** | ***Increased Emissions (Tons/year)*** | | |
|---|---|---|---|
| | ***Incremental Energy Use*** | | |
| | ***2 Percent*** | ***6 Percent*** | ***8 Percent*** |
| *$NO_x$* | *28.5* | *95.4* | *113.9* |
| *$SO_2$* | *48.4* | *145.2* | *193.6* |
| *$PM/PM_{10}$* | *19.9* | *59.8* | *79.8* |
| *CO* | *85.4* | *256.3* | *341.7* |
| *VOC* | *2.0* | *6.0* | *8.0* |
| *Sulfuric acid* | *2.4* | *7.2* | *9.6* |
| *Lead* | *0.01* | *0.03* | *0.04* |
| ***Total*** | ***186.6*** | ***559.9*** | ***746.6*** |

*Table 12 illustrates that each of the Holcomb 2-3 steam generators would increase total emissions of PSD pollutants more than 550 tons/yr for the 6 percent scenario, which is supported by EPA's analysis and Tri-State's evaluation of cooling options for the Colorado Power Project. Using the 2% scenario, the increase in emissions of PSD pollutants would exceed 180 tons/yr. The maximum reduction in $PM_{10}$ emissions that would result from the replacement of one of the cooling towers with an ACC would not exceed 22.4 tons/year. The available information on the relative plant efficiency of the wet vs. dry cooling tower systems suggests that the actual increase in plant emissions from stack and other sources, even assuming only a 2% penalty, would greatly outweigh any reduction in cooling tower PM emissions.*

*<u>Water Use:</u> Despite the inaccurate contention that wet FGD was rejected solely on the basis of water use, it is not appropriate to conclude that Sunflower should also reject wet cooling towers as well. Sunflower considered the water use impacts associated with the project and made best efforts to minimize the use of water. First, Sunflower has selected supercritical pulverized coal because it is the most efficient way to generate energy, thereby minimizing water use, fuel use, and emissions associated with the production of the needed energy. Second, the use of high efficiency drift eliminators reduces the consumptive use of water by the cooling tower. Finally, by designing a zero discharge system, Sunflower has minimized the water consumed on site.*

*In summary, the use of a dry cooling system would result in a net increase in emissions at Holcomb, and the efficiency loss and costs of such a system are excessive in relation to any potential benefit, even if the increased emissions associated with that efficiency loss were ignored. Therefore, the choice of a wet cooling system with a high efficiency drift eliminator is BACT for PM emissions for this source.*

**BACT for Cooling Towers (SCC III J b)**

Comment 51: Even if BACT is established based on a cooling tower, the permit must include a PM limit rather than a drift rate. Even if cooling towers with drift eliminators is selected as the basis for a PM BACT limit for the cooling tower, the 0.0005% drift limit is not sufficient. The PSD permit must contain a numeric PM emission limit. Moreover, the permit must require periodic testing of the cooling towers because drift eliminator performance can degrade over time. Therefore, merely requiring that the cooling tower be designed to achieve 0.0005% drift is insufficient to ensure that the cooling tower is actually achieving that rate of drift over time.

***KDHE Response:***

*KDHE considered the use of a calculated emission limit based on cooling tower flow rate and total dissolved solids (TDS) content as a means of determining compliance with the PM emissions from the cooling tower. This method has been employed in other permits. Based on the expected flow rate and the allowable TDS concentration and the design efficiency of the drift eliminator, the emission limit for the cooling tower for each unit would be 5.1 lb / hour.*

*The final permit includes a PM emission limit of 5.1 lb/hour for the cooling tower. The method of demonstrating compliance is work practices (i.e. maintenance of the drift eliminators as well as the entire cooling tower system) and limiting the TDS content of the cooling water to less than or equal to 9,000 ppm.*

*Emission testing of cooling systems is not the required method for determination of compliance with PM emissions from cooling towers. Testing of cooling tower emissions is impractical and not an appropriate means of verifying compliance. The methods and limits in the final permit are appropriate and consistent with the decisions and practices in the industry. The cooling water flow for a large base load unit is constant, thus monitoring TDS is the best indicator for PM emissions from the cooling tower.*

*Several other projects have dealt with the issue of determining compliance with cooling tower particulate emissions and have adopted approaches like that proposed for Holcomb. For example, the Illinois EPA noted in the April 2005 Responsiveness Summary to comments on the Prairie State project:*

> *"336. The permit should have testing and monitoring requirements for particulate emissions from all operations at the plant, including the cooling tower, the gas fired auxiliary boiler and fugitive dust from roadways and other open areas.*
>
> *The permit includes appropriate compliance requirements for these operations at the proposed plant. Given the nature of these operations and the types of control measures that are used, compliance procedures address proper implementation of control measures rather than direct measurement of particulate emissions by testing and monitoring."*

*This finding was not contested on appeal before the EAB.*[50]

[50] *The Prairie State permit in Condition 2.3 requires: "The Permittee shall operate and maintain the affected units including the drift eliminators, in a manner consistent with good air pollution control practice for minimizing emissions"; "2.3.7 Emission*

*In the case of the Weston 4 unit issued to Wisconsin Public Service Corporation (WPSC), Sierra Club had argued that BACT is the equivalent of what is proposed for Holcomb 2-3, that is, particulate matter from the cooling towers will be controlled to 0.0005% by drift eliminators. The decision of the State of Wisconsin Division of Hearing and Appeals[51] held:*

> ***"Cooling Towers***
>
> *28. The permit requires a mass emission limit from the cooling tower of 3.76 lbs./hr., and includes compliance demonstration measures (1) monitoring water usage; (2) operating the cooling tower and drift eliminators in accordance with manufacturer specifications; and (3) maintaining MSDS sheets of chemicals used to treat water in the cooling tower. (Ex. 102) In addition, pursuant to WPSC's WPDES permit, the facility will be required to limit total dissolved solids in the water condensate. (TR, p. 674) As WPSC's expert testified, condensate measured in the water discharge will yield a reliable basis from which to determine cooling tower emissions. Id.*
>
> *29. During the course of the proceedings, Sierra Club and WPSC agreed that the drift eliminators which WPSC plans to install at Weston 4 will control the particulate drift from the cooling towers to 0.0005%. However, the two parties could not agree on the level at which the corresponding BACT emission limit for PM from the cooling tower should be reduced. Further, WDNR recommended that the Division direct the permit holder to request a revision to the permit to reflect the improved drift elimination capability of the control device (0.0005%) and to include a corresponding reduction in the PM emission limit on a lb/hr basis for the cooling tower in a revised permit.*
>
> *30. Based upon the agreement of the parties, the permit is modified as follows:*
>
> *Based on the agreement of the Sierra Club and WPSC that the drift efficiency for the cooling tower should be established at 0.0005%, the Department recommends that the Division direct WPSC to request a revision to the air construction permit to reflect this change, along with a corresponding adjustment to the particulate matter emission limits (lb/hr) for the cooling tower."*

*Thus, the Weston 4 case supports incorporation of the PM limit into the final permit. The Weston 4 permit, as is typical, does not include a requirement to directly measure cooling tower emissions.*

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*Limitations : The total annual emissions of particulate matter from the affected units shall not exceed 15.0 tons/year, as determined by appropriate engineering calculations;" and "2.3.8 Emission Testing None".*

[51] *In the Matter of an Air Pollution Control Construction Permit Issued to Wisconsin Public Service Corporation for the Construction and Operation of a 500 MW Pulverized Coal-Fired Power Plant Known as Weston Unit 4 in Marathon County, Wisconsin Dated at Madison, Wisconsin on February 10, 2006.*

**$NO_x$ BACT and Emission Limits (SCC III K)**

**Comment 52:**

The $NO_x$ emission limit in the draft permit is not BACT. The Permit sets a $NO_x$ BACT emission limit of 0.07 lb/mmBtu based on a 30-day rolling average. The Permit contains a 30-month optimization period during which the $NO_x$ limit is 0.10 lb/mmBtu based on a 30-day rolling average. During this optimization period, the owner must only "operate and maintain the SCR system and demonstrate "best practices" to achieve 0.07 lb/mmBtu." These limits exclude periods of startup, shutdown, and malfunction. These limits are not BACT for numerous reasons, set out below.

The Application does not contain a top-down BACT analysis for $NO_x$, consistent with the five-step procedure set out in the *NSR Manual*. Second, the application does not use the substantial body of actual $NO_x$ continuous emissions monitoring (CEMS) data compiled by the U.S. EPA to establish BACT, even though this is the largest collection of such data for $NO_x$ controls in the world.

***KDHE Response:***

*A top-down analysis of BACT for $NO_x$ was performed. CEM data was used to compile that information. Since the draft permit was prepared, new information with regard to CEM operational data and recent permit developments has become available. The $NO_x$ BACT limit has been revised to 0.05 lb/mmBtu on a 30-day rolling average basis. Recent decisions have clarified that BACT limits include numeric limits for startup and shutdown when emissions are measurable, instead of work practice standards. Therefore the final permit contains a limit that applies to startup and shutdown periods.*

*The top down BACT analysis for $NO_x$ is documented in Part 4.0 of the Holcomb PSD Permit Application (see pages 4-16 and 4-18 to 4-31).*

*The Holcomb BACT analysis contains all of the steps identified in the NSR Manual:*[52]

- *Step 1-Identify and Evaluate Potential Control Options: The LNB, staged combustion, SOFA, SNCR, RRI and SCR processes are described and analyzed. (see Table 4-7 on page 4-16 and pages 4-18 to 4-19)*
- *Step 2-Eliminate Technically Infeasible Options: the SNCR and RRI options are rejected as being less efficient than the combination of boiler controls and SCR (page 4-19, Section 3.1.1.1)*
- *Step 3-Rank remaining technologies: All of the technologies identified in Table 4-7 were ranked. SCR combined with boiler controls is clearly the dominant technology. (See page 4-19, Section3.1.1.1)*

[52] *NSR Manual, Table B-1 Key Steps in the Top Down Process (page B.6)*

- *Step 4-Evaluate Most Effective controls: The top control option was selected nonetheless, the environment, energy, and economic considerations of this system are considered (see pages 4-21-22).*
- *Step 5-Select BACT: The development of the proposed emission limit considered $NO_x$ emission limits. It also considered operational data for the Hawthorn 5, Wygen, and Parish generating units (see page 4-25- to 4-28). Information from the technical literature was also considered. KDHE selected the emission limit with consideration of all these factors.*

*Since the BACT analysis was performed, additional operational data has become available, and new permits have been issued.*

*Given the data that have become available, the $NO_x$ final permit limit has been revised to 0.05 lb/ mmBtu on a 30-day rolling average basis, and the initial higher limit has been removed.*

*Changes have been made to the emission limitation after consideration of operational data, technical literature, and recent permits, including the following:*

*Operational data: CEM data from various generating units supported a lower emission limit than the original BACT determination. In addition to the units examined by Sierra Club (see Sierra Club Comments Table 1), KDHE examined data for Hawthorn 5, J.H. Miller 1-4, Parish 4, 5, 7, and 8, Pleasant Prairie, and Wygen 1. These data show a wide range of outlet $NO_x$ emissions from units using PRB coal with SCR systems. The lowest-emitting units (e.g., Parish) have some periods in which they achieve 30-day rolling average $NO_x$ emissions of approximately 0.03 lb/mmBtu. These same units have 30-day rolling average periods in which $NO_x$ emissions are in excess of 0.05 lb/mmBtu, as shown in Sierra Club Comments Table 1. The data also show that during periods in which emissions are relatively stable that the 30-day rolling average emissions vary by as much as 0.01 lb/mmBtu during a six month period. This variation occurs due both to "spikes" in the emission rate and to more gradual variations. The data demonstrate that only the most successful SCR installations can consistently operate at emission rates below a 30-day rolling average of 0.05 lb/mmBtu.*

*These same data also provide a strong indication that hourly and daily performance of SCR systems fluctuate significantly more than 30-day rolling average performance. These variations occur for various reasons (e.g., burner-related problems or placing/removing a pulverizer in/from service) which can substantially upset the operational balance of the boiler and the SCR. For example, during a period in 2004 and 2005, Parish Unit 5 recorded a 30-day rolling average $NO_x$ emission rate in the range of 0.03 to 0.04 lb/mmBtu. However, daily average emission rates exceeded 0.06 lb/mmBtu on 15 occasions. Sierra Club notes similar variability: "Sierra Club calculated the ratio of the maximum 30-day rolling $NO_x$ rate to the maximum 24-hour NOx rate for 2005 for 22 plants achieving $NO_x$ emissions less than 0.10 lb/mmBtu. The ratio ranges from 0.13 to 0.59 and averages 0.30." These data imply that a limit such as 30-day rolling average is appropriate given the variability of performance of SCR systems, including at plants with several years of operating history.*

*<u>Technical literature:</u> KDHE examined the information cited in Sierra Club Exhibit 7, which references the technical paper presented by LG&E Energy and Babcock Power on SCR system engineering. This paper makes the following points:*

- *Outlet $NO_x$ rates from operating SCR systems range from 0.03 to 0.22 lb/mmBtu (page 71).*
- *Removal efficiencies range from 70% to 90%, with about 60% of the plants operating at removal efficiencies of less than 86%, and only about 40 percent operating at efficiencies above 86%. (page 71)*
- *Only a fraction of operating units achieve outlet $NO_x$ emission rates less than 0.05 lb/mmBtu (graph on page 72).*
- *The outlet emission rate which can be achieved with 99% confidence is <0.06 lb/mmBtu (page 77).*

*Only a few SCR installations are achieving the limit now proposed for Holcomb 2-3. The data contradict the assertion that 90% control of $NO_x$ can be attained because, assuming Sierra Club were correct that a boiler outlet $NO_x$ level of 0.2 lb/mmBtu is a "typical value", several units would be attaining $NO_x$ emission rates of 0.02 or less, which is not the case. This suggests that the claim (made in its discussion of CO and VOC limits) that operating the boiler such that CO and VOC emissions are minimized at the cost of higher $NO_x$ emissions that can be compensated for by operating the SCR at 90% or better is at best a theoretical assertion.*

*<u>Recent Permit Developments:</u> KDHE has reviewed $NO_x$ emission limits in permits that have recently been issued, proposed, or for which application has been made. During the period since the Holcomb PSD permit application was filed (February 2006), a number of permits have been issued that contain emission limits higher than those now proposed by Holcomb (including Dallman 4, Sandy Creek, Hugo 2, and JK Spruce), and other permits have been proposed with limits greater than 0.05 lb/mmBtu of $NO_x$. The four permits that have the lowest proposed emission limits for $NO_x$ are:*

- *Limestone Unit 3; Limestone County TX; Application June 2006, proposes limits of 0.070 lb/mmBtu (30-day) and 0.05 lb/mmBtu (12-month)*
- *Desert Rock; Navajo Nation, NM; Proposed Permit July 2006: limit of 0.060 lb/mmBtu (24-hour), 408 lb/hr average over 3 hour period, 378.5 lb/hr, averaged over a rolling 365-day period.*
- *Glades Power Park, Moore Haven, Florida; Application December 2006: proposes limit of 0.05 lb/mmBtu (30-day).*
- *Dry Fork, Campbell County, WY, Proposed Permit February 2007: limit 0.05 lb/ mmBtu (annual) 190.1 lb/hr (30-day).*

*Based on the SCR operational data discussed earlier, a 30-day averaging period is the most appropriate for a unit of this type. Only one of the cited projects, Glades, has a limit which directly corresponds to the limit both in the level and the averaging period.*

*The Desert Rock proposed permit limit, 0.06 lb/mmBtu, is higher than that of Holcomb but for a shorter averaging period. The operational data cited earlier indicate that a limit with a short* *averaging period such as that contained in the Desert Rock permit would entail a very significant risk of violation. The Desert Rock permit also contains a limit applicable to a rolling 365-day period of 378.5 lb/hr. As stated in the Desert Rock AAQIR, the planned heat input to each boiler is 6,800 mmBtu/hr. The 365-day rolling average limit is therefore equivalent to an average emission limit of 0.056 lb/mmBtu, which is higher than the emission limit for Holcomb. Therefore, the emission limit for Holcomb is actually lower than the emission limit for Desert Rock when stated on the same basis of a 30-day rolling average.*

*The limit in the Dry Fork permit applicable to a 30-day rolling average is expressed in lb/hr of* $NO_x$*. At the planned boiler heat input of (as noted in the Wyoming Division of Air Quality's Permit Application Analysis) of 3801 mmBtu/hr, the emission level is equivalent to 0.05 lb/mmBtu. However, to the extent that the operator can comply with such a lb/hr limit by reduction in output, the limit may be viewed as being less stringent. For example, by reducing to half load the effective limit is 0.10 lb/mmBtu.*

*Based on this analysis, the emission limit for Holcomb is the same or lower than that in any recent permit, proposed permit or permit application and therefore constitutes an appropriate BACT limit.*

*Recent decisions have clarified that BACT limits include numeric limits for startup and shut down when the emissions are measurable instead of work practice standards.*[53] *Therefore, the final permit language includes a limit that applies to startup and shutdown periods. KDHE has followed the example of other recent permits, such as Prairie State, and derived this limit from the permitted heat input rate of 6501 mmBtu/hr and the emission limit during normal operation (0.05 lb/mmBtu). The product of these two numbers is 325 lb/hour. The startup and shutdown limit will be applied on an event basis. That is, the limit is based on the total* $NO_x$ *emissions in pounds (lbs), divided by the total fired period (defined as shut down and startup).*

*In summary, a BACT analysis for* $NO_x$ *was performed in accordance with the NSR manual and subsequently new relevant information became available (new technical data and new permits became available). After reviewing the new information, modifications were made and the final permit includes a* $NO_x$ *limit of 0.05 lb/mmBtu (30 day rolling average) and a startup/ shutdown limit of 325 lb/hour.*

**$NO_x$ BACT and Emission Limits (SCC III K a)**

**Comment 53:**

Lower $NO_x$ limits have been achieved. The Application concludes "there has been no demonstration that emission limits below 0.07 lb/mmBtu can be consistently achieved over the operating life of H2, H3, and H4." A BACT limit must represent the lowest limit "*achievable*" for the source—not the lowest limit previously *achieved* over a lifetime by sources in the past. To determine the $NO_x$ control achievable over the life of the pollution control device, one need only inspect 2 to 3 years of data to determine if a given $NO_x$ rate has been achieved over the SCR's lifetime, not "the operating life" of the entire power plant.

[53] *EAB Order Denying Review in Part and Remanding in Part, Indeck-Elwood, LLC PSD Appeal No 03-04*

***KDHE Response:***

*BACT is either what is "achievable" or what has been achieved at some operating unit or units. While the "achievable" idea is very important to the "technology forcing" element of BACT, it is critical that the appropriate emission limit also provide for operating variability. What is "technically achievable" or "achieved" at some units does not directly translate into an appropriate emission limit. An appropriate emission limit must make an allowance for such variability in operation, as some aspects are not totally under the control of the operator. For example, uncontrollable variations in fuel quality may occur, and these variations will affect generation and control of $NO_x$. In the case of a new generating unit, an allowance must also be made for uncertainty in the actual performance of equipment. This consideration becomes especially important when comparisons are made to the very best operating performance achieved by a few generating units out of many in a diverse population. These views are supported by recent findings of the EPA EAB. For example, the EAB observed in its order concerning the Nevada Newmont plant (slip opinion December 21, 2005 p 18):*

> *"Instead, permit writers retain discretion to set BACT levels that 'do not necessarily reflect the highest possible control efficiencies but, rather, will allow permittees to achieve compliance on a consistent basis.' In re Steel Dynamics, Inc., 9 E.A.D. 165, 188 (EAB 2000); accord In re Three Mountain Power, L.L.C., 10 E.A.D. 39, 53 (EAB 2001). In particular, we have approved the use of a so-called "safety factor" in the calculation of the permit limit to take into account variability and fluctuation in expected performance of the pollution control methods. See, e.g., Knauf II, 9 E.A.D. at 15 ('There is nothing inherently wrong with setting an emissions limitation that takes into account a reasonable safety factor.'). As we noted in Masonite, where the technology's efficiency at controlling pollutant emissions is known to fluctuate, 'setting the emissions limitation to reflect the highest control efficiency would make violations of the permit unavoidable.' 5 E.A.D. at 560.*
>
> *In essence, Agency guidance and our prior decisions recognize a distinction between, on the one hand, measured 'emissions rates,' which are necessarily data obtained from a particular facility at a specific time, and on the other hand, the 'emissions limitation' determined to be BACT and set forth in the permit, which the facility is required to continuously meet throughout the facility's life. Stated simply, if there is uncontrollable fluctuation or variability in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the 'emissions limitation' that is 'achievable' for that pollution control method over the life of the facility. Accordingly, because the 'emissions limitation' is applicable for the facility's life, it is wholly appropriate for the permit issuer to consider, as part of the BACT analysis, the extent to which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over a long term. Thus, the permit issuer may take into account the absence of long term data, or the unproven long-term effectiveness of the technology, in setting the emissions limitation that is BACT for the facility. Masonite, 5 E.A.D. at 560 (noting that the permit issuer must have flexibility*

> *when 'the technology itself, or its application to the type of facility in question, may be relatively unproven').*"

*Therefore, in evaluating the $NO_x$ emissions of existing units and the determination of an appropriate emission limit for Holcomb, consideration must be given to uncertainties in the ability to achieve a certain emission rate at a particular facility and over time.*

**Comment 54:**

Sierra Club analyzed the data from the Acid Rain Database to determine the $NO_x$ emission rates that have been achieved in practice, a less rigorous standard than the "achievable" standard for BACT. However, even by the less stringent measure, the data demonstrate that BACT for $NO_x$ for the Holcomb units is much lower than the proposed 0.07 lb/mmBtu.

The units currently achieving low $NO_x$ emission rates are subcritical boilers. The Holcomb units will use supercritical boilers. A supercritical boiler is more efficient (typically 41%) than a subcritical boiler (typically 34-38%). This means that less coal is burned and less $NO_x$, $SO_2$, PM, $PM_{10}$, etc. are emitted from a supercritical boiler than a subcritical boiler per megawatt hour of electricity generated. Thus, the achievable $NO_x$ emission rate for a supercritical boiler should be about 20% lower than the achievable rate for a comparable subcritical boiler. This was not considered in the BACT analysis.

SCR system designers have analyzed EPA's Clean Air Market's CEMS data to determine the $NO_x$ levels that are currently being achieved by over 100 SCR-equipped coal-fired boilers. This analysis identified 25 units that are achieving $NO_x$ emissions less than 0.05 lb/mmBtu on an hourly average basis.

***KDHE Response:***

*The emission data cited by this commenter supports the final permit $NO_x$ emission limit of 0.05 lb/mmBtu. Data are provided for the 2004 and 2005 operating years for 29 generating units. Of these 29 units, two operated in both years without a 30-day rolling average period in which emissions exceeded the Holcomb $NO_x$ emission limit of 0.05 lb/mmBtu. These were Chesterfield 5 and Pleasants 2. The highest 30-day rolling average for these two plants as shown in Sierra Club Comments Table 1 is 0.046 lb/mmBtu, slightly below the $NO_x$ emission limit in the final permit. These data suggest that the limit of 0.05 lb/mmBtu is consistent with the operational performance of the lowest-emitting SCR systems identified.*

*When evaluating the statement that supercritical pulverized coal steam generators should emit less $NO_x$ than sub-critical steam generators, it is important to consider the metric upon which the limit is established. $NO_x$ emissions will be lower for a supercritical steam generator on a lb/MWh basis compared to a sub-critical boiler. However when expressed as lb/mmBtu, the emission rates for supercritical and sub-critical steam generators should be the same. Steam generator $NO_x$ emissions are affected by the design of the combustion system and its ability to limit the formation of both "thermal $NO_{x,}$" which is driven by boiler combustion temperatures and the presence of atmospheric nitrogen and oxygen, and "fuel $NO_x$" from fuel-bound nitrogen.*

*Holcomb 2-3 will take advantage of the higher plant efficiencies obtained with supercritical steam generators in reducing $NO_x$ as well as other pollutants, compared to the choice of a sub-critical boiler design. However, the selection of a supercritical versus sub-critical steam generator, alone, will not affect the boiler $NO_x$ emissions on a lb/mmBtu basis.*

**Comment 55:**

Experience outside of the United States should also be considered in a top-down BACT analysis. The 250 MW Amager Power Station in Denmark is achieving $NO_x$ levels of less than 0.04 lb/ mmBtu. This plant started up in October 2000 and was designed for 2.5% S coal, but currently burns coal with a sulfur content similar to that proposed for Holcomb.

***KDHE Response:***

*The operating information cited for the Amager power station does not identify the averaging period or other indication of the variability of performance. Taking the stated emission rate at face value, such emission rate is consistent with an emission limit of 0.05 lb $NO_x$ /mmBtu as contained in the final permit, making an appropriate allowance for operational variations.*

**Comment 56: Lower $NO_x$ limits have been permitted. (SCC III K b)**

The Application relied exclusively on previous permits to set BACT for the new Holcomb units. The Developers, however, improperly rejected three lower limits and failed to explain why others were not considered.

1. Newmont

The Newmont BACT limit of 0.067 lb/mmBtu based on a 24-hour average should have been included in the Holcomb BACT analysis. This limit sets the presumptive floor and the applicant must demonstrate that circumstances exist at Holcomb that distinguish it from Newmont that would preclude Holcomb from meeting the same limit. *NSR Manual* p. B.29. The record contains no such demonstration.

2. Trimble

Since the Developers have not demonstrated why Holcomb 2-4 cannot meet the same limit at Trimble, Trimble establishes the BACT floor for Holcomb. The Trimble Unit 2 $NO_x$ limit of 0.05 lb/mmBtu, based on a 24-hour average, is the lowest permitted $NO_x$ limit that we are aware of. It corresponds to a 30-day rolling average of 0.015 lb/mmBtu. Several vendors offered to guarantee the $NO_x$ emissions from Trimble at 0.03 to 0.04 lb/mmBtu and the unit is currently under construction. Ex. 16.

3. Desert Rock

The Desert Rock draft permit contains a $NO_x$ BACT limit of 0.06 lb/mmBtu, based on a 24-hour average. This limit is equivalent to a 30-day limit of 0.018 lb/mmBtu, much lower than proposed for Holcomb.

BACT must be established as of the date of issue of the final Permit. The applicant must demonstrate that circumstances exist at Holcomb that distinguish it from Desert Rock that would preclude Holcomb from meeting the same limit.

4. Texas Permits

The application identifies one Texas project, JK Spruce Unit 2, which had been issued a draft permit with a proposed $NO_x$ limit less than the limit selected as BACT for Holcomb.

Texas has issued preliminary determinations and draft permits for seven additional supercritical boilers fired on PRB coal: Valley, Tradinghouse, Morgan Creek, Monticello, Martin Lake, Lake Creek, and Big Brown. The $NO_x$ BACT limit for all of these units is 0.05 lb/mmBtu based on a 12-month rolling average. The May 26, 2006 supplement to the Application identifies these units, but declines to include them in the BACT analysis, claiming the Developers have proposed a more stringent averaging time (30 days). The applicant makes no showing that the lower $NO_x$ limit (0.05 lb/mmBtu) and longer averaging time (12-month) in the Texas permits is less stringent than the higher $NO_x$ limit (0.07 lb/mmBtu) and shorter averaging time (30 days) in the Holcomb permit. While it may be correct, the showing should be made on the record before dismissing these BACT determinations.

***KDHE Response:***

*Holcomb's final permit NOx emission limit is 0.05 lb/mmBtu. All recent permits, proposed permits, and applications for generating units that are comparable to the Holcomb project were considered. This commenter does not cite any permit that was not considered in Sunflower's analysis or any emission limit that, on a comparable averaging period, is lower than that for Holcomb.*

*As discussed in KDHE's response to Comments 43-48 on CO and VOC BACT, KDHE has approached $NO_x$, CO, and VOC "holistically," with highest priority being given to achieving lower $NO_x$ emissions. Table 11 illustrates that the limit of 0.05 lb/mmBtu is as low or lower than those discussed above.*

*Trimble's emission limit is expressed in terms of tons/day, not lb/mmBtu. The commenter points out that is equivalent to 0.05 lb/mmBtu limits but fails to note that this is calculated from the heat input at full load. At lower loads, the limit would actually be higher; for example, at half load the equivalent limit would be 0.10 lb/mmBtu. This gives Trimble a great deal of flexibility, including the ability to reduce load in order to maintain compliance.*

*Newmont has higher limits for both $NO_x$ and VOC than proposed for Holcomb 2-3. Newmont's $NO_x$ limit of 0.067 lb/mmBtu is on a 24 hour basis. Newmont also has an annual $NO_x$ limit of 595.7 tons per year, which can be converted to 0.073 lb/mmBtu using the maximum heat input of 2030 mmBtu/hr. One can assume that the 30 day rolling average for Newmont will be between these two rates, i.e., between 0.067 lb/mmBtu and 0.073 lb/mmBtu, which is higher than 0.05 lb/mmBtu.*

*Desert Rock and Texas units (except JK Spruce) are not final. Therefore, these are not a basis on which to make a BACT determination.*

*JK Spruce was issued with a final permit limit of 0.069 lb/mmBtu (30 day average).*

**$NO_x$ BACT and Emission Limits (SCC III K c)**

**Comment 57:**

Lower $NO_x$ limits have been guaranteed. Most major SCR vendors currently offer, and have offered and provided, SCRs guaranteed to achieve 0.03 lb/mmBtu and below for units firing all types of coal. These include Babcock Power, Haldor Topsoe, CERAM, Siemens, and Cormetech. Further, Texas concluded—over 5 years ago—that a $NO_x$ limit of 0.030 lb/mmBtu "is technically feasible… based on the literature and discussion with SCR vendors."

***KDHE Response:***

*Manufacturer guarantees may be at test conditions and for periods that differ substantially from the extended operational compliance required under a plant emission limit. As noted previously, operational data do indicate the SCRs on units burning PRB coal can achieve emissions at or below 0.03 lb/mmBtu for some periods of time. The same data indicate that there is sufficient variability and uncertainty in operation that an emission limit at this level is not BACT. The information provided in the Haldor Topsoe report, which discusses operational success with US generating units would appear to refer to the same universe of operating unit performance already considered. It is appropriate to consider a margin of operational variability in setting BACT limits so that a facility can reasonably be expected to remain in compliance with an emission limit for the entire operating life of the facility.*

*As pointed out in response to Comment 34 on the $SO_2$ BACT, manufacturers frequently use terminology such as "technically feasible" and "very achievable" in marketing their products. Statements in presentations and marketing materials are not the same as offering a guarantee which requires consistent long term compliance.*

**$NO_x$ BACT and Emission Limits (SCC III K d)**

**Comment 58:**

The application dismisses lower permitted $NO_x$ limits and lower achieved $NO_x$ emission rates using a number of long-since-debunked myths commonly advanced by applicants to avoid complying with the plain language definition of BACT.

Myth #1: Coal Type Dictates $NO_x$ Emissions.

Myth #2: SCR is Not a Mature Technology.

Myth #3: Ozone Season SCR Operation Is Not Relevant.

Myth #4: Cap and Trade Units Are Different.

***KDHE Response:***

*KDHE has not excluded operating data from any unit based on any of the four considerations identified by the commenter in this section. Therefore the comments are not applicable to the analysis of operational data for the $NO_x$ emission limit in the final permit.*

**$NO_x$ BACT and Emission Limits (SCC III K e)**

**Comment 59:**

The application contains no evidence that the proposed $NO_x$ BACT limit of 0.07 lb/mmBtu is based on the maximum degree of reduction that is achievable. This limit does not correspond to the maximum degree of reduction that is achievable by the technology selected as BACT.

The achievable $NO_x$ emission limit for the new Holcomb units would be about 0.02 lb/mmBtu, if the boiler outlet $NO_x$ were 0.2 lb/mmBtu (a typical value) and the SCR achieved 90% $NO_x$ control (also typical). Assuming a boiler outlet of 0.25 lb/mmBtu, which would be very high for a new supercritical boiler burning PRB coal, the achievable $NO_x$ emission limit would be 0.025 lb/mmBtu, one third of that picked by the applicant based on permitted levels.

***KDHE Response:***

*The revised $NO_x$ limit in the final permit is 0.05 lb/mmBtu.*

*This commenter's data show that operating data for numerous recently-completed SCR systems, including for systems with low $NO_x$ burners (e.g., the Parish units), indicate that an emission limit of 0.050 lb/mmBtu on a 30-day rolling average is appropriate, given the performance of these systems. For example, the claim of 90% removal of $NO_x$ is not specific as to the inlet SCR conditions, the averaging period, or degree of variability of performance. In this respect, the operational performance of these systems in the field is a better guide.*

*Further, it is appropriate in the determination of an emission limit for $NO_x$ , through the BACT process, to consider the extent of variability and uncertainty of performance and to allow for this in the formulation of an emission limit.*

*In a recent opinion, EPA's EAB considered the stringency of the emission limit required for BACT. Newmont at 18 (summarizing In re Kendall New Century Dev., PSD Appeal No. 03-01 (EAB Apr. 29, 2003); In re Cardinal FG Co., PSD Appeal No. 04-04 (EAB Mar. 22, 2005), In re Steel Dynamics, Inc., 9 E.A.D. 165 (EAB 2000), In re Three Mountain Power, L.L.C., 10 E.A.D. 39 (EAB 2001)). The Board summarized those opinions as standing for the proposition that "if there is uncontrollable fluctuation or variability in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the 'emissions limitation' that is 'achievable' for that pollution control method over the life of the facility." Id. The Board concluded that "the permit issuer may take into account the absence of long-term data, or the unproven long-term effectiveness of the technology, in setting the emissions limitation that is BACT for the facility." Id. The Board found that it was appropriate for the permit issuer "to determine and to consider the range of control limitations that the permittee could reasonably expect to achieve over time, particularly with respect to the coal fuel type." Id. at 22. In summary, BACT does not require speculation as to what may be achievable in the future.*

*As noted by the EAB in its recent decision concerning the Newmont BACT determination (pages 42-43):*

> *"The Board and its predecessors have had occasion to address control efficiency-related arguments in several past PSD cases and have acknowledged that permitting agencies have discretion in determining whether a particular control efficiency level is appropriate in determining the best control technology and in setting an appropriate emissions limit.[11] We have found that:*
>
> *When [a permit issuer] prescribes an emissions limitation representing BACT, the limitation does not necessarily reflect the highest possible control efficiency achievable by the technology on which the emissions limitation is based. Rather, the [permit issuer] has discretion to base the emissions limitation on a control efficiency that is somewhat lower than the optimal level. * * * There are several different reasons why a permitting authority might choose to do this. One reason is that the control efficiency achievable through the use of the technology may fluctuate, so that it would not always achieve its optimal control efficiency. * * *Another possible reason is that the technology itself, or its application to the type of facility in question, may be relatively unproven. * * * To account for these possibilities, a permitting authority must be allowed a certain degree of discretion to set the emissions limitation at a level that does not necessarily reflect the highest possible control efficiency, but will allow the permittee to achieve compliance consistently. In re Masonite Corp., 5 E.A.D. 551, 560-561 (EAB 1994)".*

*The control efficiencies cited by this comment, at best, represent the performance of systems under normal operating conditions and without consideration of an appropriate allowance to, as the EAB put it, "allow the permittee to achieve compliance consistently."*

*If the comments about achievable $NO_x$ emission limits were correct, one would observe substantial periods of emissions of $NO_x$ at a level at or below 0.025 lb/ mmBtu. However, the data offered show essentially no reported operational emissions at such levels. This suggests that the calculation is, at best, purely theoretical and unsupported by actual operating performance. As such, it cannot be the basis for a BACT determination.*

**$NO_x$ BACT and Emission Limits – Optimization Period (SCC III K f)**

**Comment 60:**

The Permit includes a 30-month optimization period during which the $NO_x$ limit is 0.10 lb/mmBtu based on a 30-day rolling average, excluding periods of startup, shutdown, and malfunction. During this optimization period, the owner "must operate and maintain the SCR system and demonstrate "best practices" to achieve 0.07 lb/mmBtu." The Permit is silent as to what happens if the 0.07 lb/mmBtu target is not met and should be modified to make KDHE's intent clear.

***KDHE Response:***

*The optimization period was not included in the final permit.*

**Lead BACT and Emission Limits (SCC III L)**

**Comment 61:**

The lead limit in the Draft Permit is 16.7 lb/TBtu (pounds per trillion Btus), averaged over the period specified in the test protocol (which is typically 3 hours). The Application argues that lead is controlled by the same equipment used to control PM and $PM_{10}$ because it is emitted as solid particulate. PSD Permit Application, p. 4-80. The Application then calculates the BACT lead limit using a confidential "EPRI Emissions Handbook." The Application does not present the equation that was used or divulge any of the assumptions that went into the calculation, leaving the reader to guess as to the $95^{th}$ percentile lead concentration, the coal ash content, and the control efficiency assumed for the fabric filters. *Id.*, p. 4-82. This undermines the requirement for public review and comment. KDHE must require the applicant to disclose its calculation and recirculate the lead BACT analysis for public review.

***KDHE Response:***

*The commenter asserts that Sunflower did not "divulge any of the assumptions that went into the calculation" of the proposed emission limit for lead. On the contrary, the BACT analysis provides the following information (See Holcomb 2-4 PSD Application, Section 4.0, page 4-82):*

> *"Lead concentrations in coal can vary significantly, even within the same supply region. Sunflower reviewed lead concentration data from coals in Wyoming (the primary supply region for PRB coal) that are provided by the USGS. These data indicated a range of lead concentrations from 0.2 to 55 ppmw. Sunflower does not know the coal lead concentrations that have been used to determine the lead emission limits for each of the projects in Table 4-21. However, it is possible that differences in the selection of the coal lead concentrations by the various projects can explain the differences in the lead emission limits, even for similar coal supplies and BACT technologies.*
>
> *Lead emissions from Holcomb 2-3 were calculated using procedures from the EPRI Emissions Handbook. The calculated emission factor (lb/TBtu) is a function of the lead and ash concentrations in the coal, and the overall particulate emission rate (lb/mmBtu). The lead emission factor for Holcomb 2-3 was estimated using typical ash content for PRB coal, the proposed BACT level for filterable $PM/PM_{10}$, and a lead concentration in the fuel derived from an analysis of USGS coal trace element data for coals from Wyoming. To account for the variability of lead concentration within the coal supply source, the $95^{th}$ percentile concentration was used in the calculation of lead emissions. The corresponding lead emission factor (16.4 lb/TBtu) is the proposed BACT emission limit for H2 and H3."*

*KDHE has the EPRI Emissions Handbook. This is a public document. This information is comparable to or greater than the detail provided in most recent BACT analysis of lead emissions in other permits and provides a clear explanation of Sunflower's approach and the sources employed. Sunflower has also provided numerous Holcomb 1 test reports to KDHE which confirm that a relatively wide range of lead emissions are possible when using PRB coal. The information provided supports the BACT analysis presented in the permit application.*

**Comment 62:**

The assumption that BACT controls for PM and $PM_{10}$ satisfy BACT for lead is not correct. Lead is volatilized in the boiler and condenses as very fine particulate matter or nanoparticles (<2.5 microns) in the pollution control train. The highest concentrations of lead are consistently found in the smallest particles. The particulate collection efficiency for baghouses designed to collect PM and $PM_{10}$ is generally lower for these nanoparticles that contain most of the lead than for larger particles. Thus, a fabric filter system designed to meet BACT for PM and $PM_{10}$ does not necessarily meet BACT for particles smaller than 10 microns where most of the lead is found. These smaller particles also cause proportionately more of the adverse health impacts because they can penetrate deep into the lung.

***KDHE Response:***

*Lead is preferentially associated with the finer particulate matter. However, the commenter is incorrect in contending that a fabric filter is not effective in collecting such particles. For example, in SierraClub's Comments, (Exhibit 39, Figure 9,) clearly shows the relatively constant collection* *efficiency of a fabric filter across a range of sizes, with good collection efficiency in the very smallest range of particle size.   Figure 9 is shown below.*

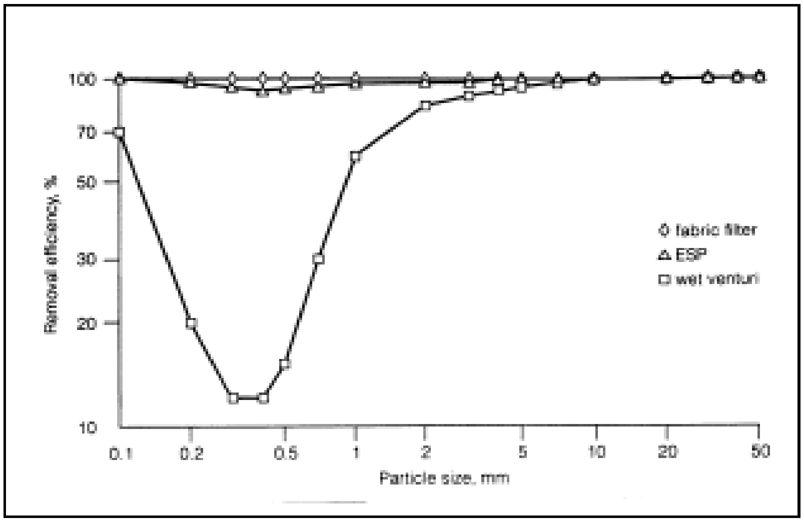


**Figure 9.** Removal efficiency of three common particle removal technologies used on large stationary combustion systems. Reproduced by permission of IEA.[144]

*A review of recent permits including units using both eastern and western coals shows that nearly all selected a fabric filter as the control technology for lead.*

**Comment 63:**

A BACT analysis for lead must consider methods to enhance the removal of these finer particles. Methods to enhance the control of fine lead particles include: (1) use of a filtration media with a higher removal efficiency for nanoparticles; (2) use of a wet ESP; and (3) use of an agglomerator upstream of the baghouse. An agglomerator uses electrical charges to attach nanoparticles to larger particles, which are then more efficiently removed by the baghouse.  Agglomerators have been used to reduce opacity (caused by nanoparticles) and PM at several coal fired power plants.

***KDHE Response:***

*As discussed above, fabric filters are effective for fine particles thus additional controls are not necessary.  The technology suggested is not applicable to Holcomb 2-3.   The commenter suggests consideration of an "agglomerator" to enhance collection of very fine particulates. The technology referred to as described in Sierra Club Exhibit 37 and in materials available on the website of the developer of the technology[54] appears never to have been tested in conjunction with a fabric filter system. The few applications cited are for the enhancement of performance of ESP, which suffer from a reduction in collection efficiency for particles in the range of 1*

[54] *http://www.indigotechnologies-us.com/*

*micrometer. This technology has not been demonstrated in conjunction with a fabric filter and may or may not produce a meaningful enhancement in performance.*

*The commenter also suggests consideration of a wet ESP for the purpose of collection of fine particles. KDHE been unable to document a demonstration of the effectiveness of the combination of a wet ESP following a LSD-FGD and fabric filter system. Sierra Exhibit 36, a presentation by Wheelabrator Corp. purports to show that the Longview project has such a configuration. The effectiveness of such a system in achieving a further reduction in lead emissions compared to the selected control system has not been demonstrated.*

**BACT for Material Handling (SCC III M)**

**Comment 64:**

The draft permit does not contain any BACT conditions for material handling. The proposed Holcomb 2-4 construction project will result in increased emissions of PM and $PM_{10}$ from equipment used to handle, convey, and store materials including coal, limestone, gypsum, fly ash, and bottom ash. Some of this equipment is new and some are existing sources that will be either modified, or used at a higher rate. BACT limits apply to these modified sources. However, the draft permit contains no BACT limits for these sources and it appears that KDHE never prepared a BACT analysis for these sources.

Other permits include actual numeric BACT limits for material handling, including:

- 0.004 gr/dscf for coal and limestone collectors at the Elm Road, WI
- 0.005 gr/dscf for coal and limestone collectors at the MidAmerican, IA
- 0.009 gr/dscf for coal collectors at the Wygen 2, WY
- 0.005 gr/dscf for baghouses at Indeck-Illwood, IL

Limits on emission rates are feasible for the new and modified material handling processes, as evidenced by the fact that other facilities have emission limits.

***KDHE Response:***

*The final permit has been revised to include an emission limitation of 0.005 gr/dscf on coal handling emission units and an emission limitation of 0.01 gr/dscf on all other emission units equipped with small baghouses. The final permit also establishes an initial performance test requirement for one baghouse in each of the three material handling systems (coal, ash, and lime). On-going compliance for these control devices can be assured by utilizing broken bag detectors and/or particulate monitors, by observing pressure drop, or by periodic quantitative and qualitative observation, or by individual methods, or a combination thereof, as is appropriate for each type of material being handled and as to the location in which it is installed.*

*A review of the projected emission rates from each emission unit and any associated flow rates confirms that emission estimates are at or below the levels of other comparable permits. The* *permit application contained a top-down BACT evaluation for all materials handling systems and selected the top feasible control for each emission point. Part 4.0 of the PSD permit application contains a detailed discussion of the various emission points, and classified them as to which were controlled by the best available technologies. The permits cited in this comment do not contain strict emission limits on all emission points associated with certain types of materials handling.*

*While the Elm Road permit does limit coal handling emissions to 0.004 gr/dscf, the facility will utilize bituminous coal. PRB coal, being much dustier, will generate a higher inlet grain loading to the dust collector, with a correspondingly slightly higher outlet emission potential. Other emission points at Elm Road are identified with limits greater than 0.004 gr/dscf. These, mostly dealing with ash handling, are required to demonstrate compliance utilizing emission factors only; no performance testing is required. Some of these points do require either an initial performance test to demonstrate compliance with the outlet grain loading or the use of an emission factor to demonstrate compliance utilizing the throughput of the system.*

*The MidAmerican permit does list an emission rate of 0.005 gr/dscf on coal and flyash handling operations. However, this emission rate is not found in the PSD permit itself, only in the Technical Support Document; and the compliance with the limit is determined through opacity limits, not emission testing. The lime filter separator, lime silo, and urea silo each have an emission limit of 0.01 gr/dscf, all of which are subject to compliance testing and have opacity requirements. However, these limits are not nearly as stringent as the commenter indicates.*

*Although the final Wygen 2 permit does require an initial Method 5 test to determine that the emission rate is 0.009 gr/dscf, the permit requires no continuous or intermittent monitoring. In essence, this is a one time test to determine compliance when the equipment is new and in prime condition. Furthermore, while a numeric limit is in place, it is less strict than an on-going work practice standard.*

*The Indeck-Elwood permit indicates that this limit is in place and that an initial compliance test is required in order to determine initial compliance, on-going compliance is determined though monitoring the pressure drop across the individual baghouses.*

*In contrast, Desert Rock contains no numeric emission limits on the materials handling sources. Compliance is determined through opacity monitoring only. Similarly, Prairie State requires testing of emission limits via Methods 5 or 17 on certain processes. Continuing compliance is assured by Method 9 (opacity) monitoring and monitoring pressure drop on the baghouses.*

*Best available controls have been applied to each new or modified material handling source at Holcomb. A review of the projected emission rates from each emission unit and any associated flow rates indicates that the emission rates are at the levels of other comparable permits. The final permit includes an emission limitation of 0.005 gr/dscf on coal handling emission units and an emission limitation of 0.01 gr/dscf on all other emission units equipped with small baghouses. The final permit also establishes an initial performance test requirement for one baghouse in each of the three material handling systems (coal, ash, and lime). On-going compliance for these control devices can be assured by utilizing broken bag detectors and/or particulate* *monitors, by observing pressure drop, or by periodic quantitative and qualitative observation, or by individual methods, or a combination thereof, as is appropriate for each type of material being handled and as to the location in which it is installed.*

**BACT for Auxiliary Boilers (SCC III N)**

**Comment 65:**

The draft permit does not include adequate BACT limits for the auxiliary boilers and emergency generators. Each of the new Holcomb Units will have a corresponding Auxiliary Boiler capable of 200 mmBtu per hour. BACT for the Boiler includes the use of natural gas, low $NO_x$ burners, Flue gas recirculation, and catalytic converters. The Draft Permit establishes a limit of 0.10 lb/mmBtu for the auxiliary boilers. However, this is not BACT. A number of gas-fired boilers achieve much lower emission rates. The Calpine Company's Turner Energy Center has $NO_x$ limit of 0.011 lb/mmBtu using Selective Catalytic Reduction, the Philadelphia Naval Shipyard's Natural gas boiler has a $NO_x$ limit of 0.035 lb/mmBtu using low-$NO_x$ burners and natural gas, and Pine Bluff Energy, LLC, has a boiler with an emissions limit of 0.037 lb/mmBtu using low $NO_x$ burners, flue gas recirculation and good combustion practices. Each of these units is listed in the EPA RACT/BACT/LAER Clearinghouse (RBLC) as having a lower emission limit than the limit proposed for the boilers at Holcomb.

**KDHE Response:**

*The final permit emission limits for the auxiliary boilers have been revised to 0.036 lb/mmBtu for $NO_x$, 0.08 lb/mmBtu for CO, and 0.005 lb/mmBtu for VOC.*

*The BACT emission limit selection for $NO_x$, CO, and VOC was conducted in a holistic fashion recognizing the interrelationship in the formation, relative level of concern, and impact of each pollutant. Achieving CO emission reductions at the expense of increasing $NO_x$ emission levels is generally not encouraged. Simultaneously balancing low CO and $NO_x$ emission levels at the boiler outlet is an appropriate consideration in the boiler design and operation. Ultimately these factors need to be considered when selecting the BACT emission limit as well. It is inappropriate to simply look at one pollutant at any particular facility without considering the emission limits of the other two pollutants.*

*As such, all sources in the RBLC were examined and compiled with the applicable results in Table 13 on the following page, with the final permit limits for Holcomb.*

**TABLE 13. RBLC DETERMINATIONS FOR NATURAL GAS FIRED AUXILIARY BOILERS AND HOLCOMB UNITS 2-3**

| Facility | State | $NO_x$ Emission Limit lb/mmBtu) | Control Technology | CO Emission Limit (lb/mmBtu) | Control Technology | VOC Emission Limit (lb/mmBtu) | Control Technology | Permit Date | Notes |
|---|---|---|---|---|---|---|---|---|---|
| Holcomb Units 2-3 | KS | 0.036 | FGR, LNB | 0.08 | GCP | 0.005 | GCP | 2007 | |
| Forsyth Energy Plant | NC | 0.137 | LNB | 0.082 | LNB, GCP, N. gas | 0.005 | LNB, GCP, N. Gas | 9/29/2005 | |
| WPS - Weston Plant | WI | 0.1 | LNB | 0.08 | N. gas, GCP, LNB | 0.005 | N. Gas, GCP, LNB | 10/19/2004 | |
| Maidsville Power Plant | WV | 0.098 | LNB | 0.04 | GCP, N. gas | 0.005 | GCP, N. Gas | 3/2/2004 | |
| Rocky Mountain Energy Center, LLC | CO | 0.038 | LNB | 0.039 | GCP | | | 8/11/2002 | |
| AES Red Oak LLC | NJ | 0.036 | | 0.05 | GCP | 0.004 | GCP | 10/24/2001 | LAER |
| PSEG Lawrenceburg Energy Facility | IN | 0.036 | LNB | 0.082 | GCP, N. gas | 0.005 | GCP, N. Gas | 6/7/2001 | |
| Williams Refining & Marketing, L.L.C. | TN | 0.06 | | 0.18 | | | | 4/3/2002 | |
| Tenaska Arkansas Partners, LP | AR | 0.04 | FGR | 0.11 | GCP | 0.004 | GCP | 10/9/2001 | |
| VCU East Plant | VA | 0.1 | GCP, LNB, FGR | 0.099 | GCP | 0.014 | GCP | 3/31/2003 | |
| VCU East Plant | VA | 0.1 | GCP, LNB, FGR | 0.099 | GCP | 0.014 | GCP | 3/31/2003 | |
| Miller Brewing Company – Trenton | OH | 0.7 | OFA | 0.084 | | 0.011 | | 11/15/2001 | |
| Xcel Energy - Riverside Plant | MN | | | 0.08 | GCP | 0.005 | GCP | 5/16/2006 | |
| Proctor & Gamble Manufacturing Company | TN | | | | | 0.024 | | 3/5/2001 | |
| Proctor & Gamble Manufacturing Company | TN | | | | | 0.024 | | 3/5/2001 | |
| Amella Energy Center | TX | 0.04 | | 0.09 | | 0.02 | | 3/26/2002 | Case-by-Case |
| Liberty Generating Station | NJ | 0.036 | SCR | 100 ppm | CO catalyst | 50 ppm | CO catalyst | 3/28/2002 | Case-by-Case |
| Turner Energy Center, LLC | OR | 0.011 | SCR | 0.038 | CO catalyst | 0.004 | CO catalyst | 1/6/2005 | Never Built |

*Utilizing the information in Table 13, a review of the BACT determination for the auxiliary boilers in the Holcomb 2-4 PSD draft permit can be performed.*

*The Holcomb auxiliary boilers will be designed with low- $NO_x$ burners and Flue Gas Recirculation for $NO_x$ control and will be fired only with pipeline natural gas. Potential $NO_x$ emissions from the auxiliary boilers will also be limited by limiting the annual hours of operation. In order to estimate maximum annual emissions from the auxiliary boilers, it was assumed that each auxiliary boiler would operate for a maximum of 876 hours annually (i.e., 10% utilization). This assumption is conservative, because in most years the auxiliary boilers are expected to operate fewer than 876 hours per year. Nevertheless, limiting the hours of operation to 876 per year will reduce the potential annual emissions from each auxiliary boiler by 90%.*

*Both the Philadelphia Naval Shipyard and Pine Bluff Energy boilers cited in the comment are base load type boilers, and therefore the $NO_x$ emissions controls are not directly comparable to the limited operation auxiliary boilers being proposed by Holcomb. Calpine's Turner Energy Center facility was never constructed, and as a result the BACT $NO_x$ emission limit of 0.011 lb/mmBtu was never demonstrated in practice.*

*Table E-10 of the PSD Application was updated and( is designated as Table 14 below) to provide a summary of EPA's RACT/BACT/LAER Clearinghouse (RBLC) for $NO_x$ determinations made for natural gas fired boilers from 1/1/2001 thru 12/31/2006. The cases highlighted in the table represent RBLC determinations that are not BACT determinations or may not be applicable to this project.*

***TABLE 14. (UPDATED TABLE E-10 OF THE PSD APPLICATION)***
***RBLC $NO_x$ DETERMINATIONS FOR NATURAL GAS FIRED AUXILIARY BOILERS***

| *Facility* | *State* | *NOx Emission Limit (lb/mmBtu)* | *Control Technology* | *Permit Date* | *Notes* |
|---|---|---|---|---|---|
| *Miller Brewing Company - Trenton* | *OH* | *0.7* | *OFA* | *11/15/2001* | |
| *Forsyth Energy Plant* | *NC* | *0.137* | *LNB* | *9/29/2005* | |
| *VCU East Plant* | *VA* | *0.10* | *GCP, LNB, FGR* | *3/31/2003* | |
| *VCU East Plant* | *VA* | *0.10* | *GCP, LNB, FGR* | *3/31/2003* | |
| *WPS – Weston Plant* | *WI* | *0.100* | *LNB* | *10/19/2004* | |
| *Maidsville Power Plant* | *WV* | *0.098* | *LNB* | *3/2/2004* | |
| *Williams Refining & Marketing, L.L.C.* | *TN* | *0.06* | | *4/3/2002* | |
| *Amella Energy Center* | *TX* | *0.040* | | *3/26/2002* | *Case-by-Case* |
| *Tenaska Arkansas Partners, LP* | *AR* | *0.04* | *FGR* | *10/9/2001* | |

| *Facility* | *State* | *NOx Emission Limit (lb/mmBtu)* | *Control Technology* | *Permit Date* | *Notes* |
|---|---|---|---|---|---|
| *Rocky Mountain Energy Center, LLC* | *CO* | *0.038* | *LNB* | *8/11/2002* | |
| *Liberty Generating Station* | *NJ* | *0.036* | *SCR* | *3/28/2002* | *Case-by-Case* |
| *AES Red Oak LLC* | *NJ* | *0.036* | | *10/24/2001* | *LAER* |
| *PSEG Lawrenceburg Energy Facility* | *IN* | *0.036* | *LNB* | *6/7/2001* | |
| *Turner Energy Center, LLC* | *OR* | *0.011* | *SCR* | *1/6/2005* | *Never Built* |

*The Turner Energy Center limit has not been demonstrated because the facility was never constructed and does not need to be considered, and the other highlighted determinations were based on either state specific case-by-case determinations or LAER. The BACT determination of LNB and FGR is correct. Therefore, 0.036 lb/mmBtu is the appropriate BACT emission limit for auxiliary boilers. The final permit limits will balance the $NO_x$, CO, and VOC emission rates, as these pollutants must be examined on a holistic basis.*

**Comment 66:**

The CO limits for the auxiliary boilers do not represent BACT. The draft permit includes a limit of 0.08 lb/mmBtu based on combustion controls. However, other facilities have lower BACT limits. The Calpine Co. Turner Energy Center's auxiliary boiler has a CO limit of 0.038 lb/mmBtu using an Oxidation Catalyst. Even without the use of this higher-ranked pollution control technology, Longview Power's Maidsville plant has a limit of 0.04 lb/mmBtu using good combustion practices and natural gas. The Pine Bluff Energy has a CO limit of 0.044 lb/mmBtu using good combustion practices.

***KDHE Response:***

*The Holcomb auxiliary boilers will utilize good combustion practices for CO control and will be fired only with pipeline natural gas. Potential CO emissions from the auxiliary boilers will also be limited by limiting each boiler's annual operation to 876 hours per year.*

*The Pine Bluff Energy boiler cited in the comment is a base load type boiler and therefore the CO emissions controls are not directly comparable with the limited operation auxiliary boilers being proposed by Holcomb. Calpine's Turner Energy Center facility was never constructed, and as a result the BACT CO emission limit of 0.038 lbs/mmBtu was never demonstrated in practice.*

*Table E-12 of the PSD Application was updated to provide a summary of EPA's RACT/BACT/LAER Clearinghouse (RBLC) for CO determinations (including the Longview Power Maidsville Plant) made for natural gas fired boilers from 1/1/2001 thru 12/31/2006 and is shown below as Table 15. The cases highlighted in the table* *represent RBLC determinations that are not BACT determinations or may not be applicable to this project.*

**TABLE 15. (UPDATED TABLE E-12 OF THE PSD APPLICATION)**
**RBLC CO DETERMINATIONS FOR NATURAL GAS FIRED AUXILIARY BOILERS**

| Facility | State | CO Emission Limit (lb/mmBtu) | Control Technology | Permit Date | Notes |
|---|---|---|---|---|---|
| Williams Refining & Marketing, L.L.C. | TN | 0.180 | | 4/3/2002 | |
| Tenaska Arkansas Partners, LP | AR | 0.110 | GCP | 10/9/2001 | |
| VCU East Plant | VA | 0.099 | GCP | 3/31/2003 | |
| VCU East Plant | VA | 0.099 | GCP | 3/31/2003 | |
| Amella Energy Center | TX | 0.090 | | 3/26/2002 | Other |
| Miller Brewing Company - Trenton | OH | 0.084 | | 11/15/2001 | |
| PSEG Lawrenceburg Energy Facility | IN | 0.082 | GCP, N. gas | 6/7/2001 | |
| Forsyth Energy Plant | NC | 0.082 | LNB, GCP, N. gas | 9/29/2005 | |
| Xcel Energy - Riverside Plant | MN | 0.080 | GCP | 5/16/2006 | |
| WPS – Weston Plant | WI | 0.080 | N. gas, GCP, LNB | 10/19/2004 | |
| AES Red Oak LLC | NJ | 0.050 | GCP | 10/24/2001 | |
| Maidsville | WV | 0.040 | GCP, N. gas | 3/2/2004 | |
| Turner Energy Center, LLC | OR | 0.038 | CO catalyst | 1/6/2005 | Never Built |
| Rocky Mountain Energy Center, LLC. | CO | 0.039 | GCP | 8/11/2002 | |
| Liberty Generating Station | NJ | 100 ppm | CO catalyst | 3/28/2002 | Other |

*The three most current determinations (Forsyth, Xcel, and WPS) indicate an emission limit at or above the proposed Holcomb limit of 0.08 lb/mmBtu. The BACT determination of LNB, FGR, GCP, and the use of natural gas is correct and the emission rate of 0.08 lb/mmBtu is appropriate, considering recent BACT determinations for auxiliary boilers.*

**Comment 67:**

The $PM_{10}$ limits for the Holcomb auxiliary boilers are not BACT. The proposed limit is 0.01 lb/mmBtu. However, other facilities are subject to lower emission limits that were not considered in the BACT review for the Holcomb Station. The Longview Power Maidsville plant has a limit of 0.0022 lb/mmBtu, BASF's Freeport Cogeneration Facility has a $PM_{10}$ limit of 0.0005 lb/mmBtu, and the Pine Bluff Energy has a limit of 0.005 lb/mmBtu. These units all use the same "control option" being proposed for the auxiliary boilers: using clean fuels and good combustion. Therefore, it must be assumed that the Holcomb Station auxiliary boilers can also achieve the lowest of these limits.

***KDHE Response:***

*The Holcomb auxiliary boilers will be fired only with pipeline natural gas, a very low ash fuel, which inherently produces low $PM_{10}$ emissions. In addition $PM_{10}$ emissions from the auxiliary boilers will also be limited by restricting the annual operation of each boiler to 876 hours per year. Holcomb based the proposed $PM_{10}$ emissions from the auxiliary boilers on the AP-42 emission factor of 0.0076 lb/mmBtu for filterable and so-called condensable $PM_{10}$ emissions. The final permit limit of 0.01 lb/mmBtu is the result of rounding this emission factor. This is the BACT emission rate, as it is based on typical concentrations of particulate matter in the gas stream and formation of additional PM in the combustion process. There are no back-end control devices that can be utilized to further reduce PM emissions. Therefore, BACT has been properly identified and an appropriate emission limit selected.*

**Comment 68:**

Other facilities are subject to lower VOC limits as well. The Draft Permit includes a limit of 0.01 lb/mmBtu from the auxiliary boilers. Based on the U.S. EPA's AP-42 Emission Factor, the emissions should never be greater than 0.0053 lb/mmBtu. However, even lower emissions are possible and must be assumed to be BACT for the Holcomb Station auxiliary boilers. The Calpine Turner Energy Center has a VOC BACT limit of 0.0044 lb/mmBtu using an Oxidation Catalyst. This control technology was not considered in the BACT review for Holcomb, but must be assumed to be BACT. Moreover, Pine Bluff Energy LLC is subject to a VOC limit of 0.002 lb/mmBtu based only on good combustion practices. It must be assumed that the Holcomb auxiliary boilers can achieve 0.002 lb/mmBtu and must be subject to that limit as BACT for VOC.

***KDHE Response:***

*The final permit revised the VOC emission limit to 0.005 lb/mmBtu.*

*The Holcomb auxiliary boilers will utilize good combustion practices for VOC control and will be fired only with pipeline natural gas. Potential VOC emissions from the auxiliary boilers will also be limited by restricting their annual operation to 876 hours per year per boiler.*

*The Pine Bluff Energy boiler cited in the comment is a base load type boiler, and therefore the VOC emissions controls are not directly comparable with the limited operation auxiliary boilers being proposed by Holcomb.*

*Table E-14 of the PSD Application was updated to provide a summary of EPA's RACT/BACT/LAER Clearinghouse (RBLC) for VOC determinations made for natural gas fired boilers from 1/1/2001 thru 12/31/2006 and is shown as Table 15, below. The cases highlighted in the table represent RBLC determinations that are not applicable to this project. The Turner Energy Center facility was never constructed, and the other three* *highlighted determinations were based on either state specific case-by-case determinations or LAER.*

**TABLE 16. (UPDATED TABLE E-14 OF THE PSD APPLICATION)**
**RBLC VOC DETERMINATIONS FOR NATURAL GAS FIRED AUXILIARY BOILERS**

| Facility | State | VOC Emission Limit (lb/mmBtu) | Control Technology | Permit Date | Notes |
|---|---|---|---|---|---|
| Proctor & Gamble Manufacturing Company | TN | 0.024 | | 3/5/2001 | |
| Proctor & Gamble Manufacturing Company | TN | 0.024 | | 3/5/2001 | |
| VCU East Plant | VA | 0.014 | GCP | 3/31/2003 | |
| VCU East Plant | VA | 0.014 | GCP | 3/31/2003 | |
| Miller Brewing Company - Trenton | OH | 0.011 | | 11/15/2001 | |
| Xcel Energy - Riverside Plant | MN | 0.005 | GCP | 5/16/2006 | |
| PSEG Lawrenceburg Energy Facility | IN | 0.005 | GCP, N. Gas | 6/7/2001 | |
| Forsyth Energy Plant | NC | 0.005 | LNB, GCP, N. Gas | 9/29/2005 | |
| Turner Energy Center, LLC | OR | 0.004 | CO catalyst | 1/6/2005 | Never Built |
| WPS - Weston Plant | WI | 0.005 | N. Gas, GCP, LNB | 10/19/2004 | |
| Maidsville | WV | 0.005 | GCP, N. Gas | 3/2/2004 | |
| AES Red Oak LLC | NJ | 0.004 | GCP | 10/24/2001 | LAER |
| Tenaska Arkansas Partners, LP | AR | 0.004 | GCP | 10/9/2001 | |
| Amella Energy Center | TX | 0.020 | | 3/26/2002 | Other |
| Liberty Generating Station | NJ | 50 ppm | CO catalyst | 3/28/2002 | Other |

*An analysis of recent RBLC determinations indicates that an emission limit of 0.005 lb/mmBtu is appropriate for this type of source. Therefore, the permit contains an emission limit of 0.005 lb/mmBtu. While Tenaska does have a lower limit (0.004), this is accompanied by a much higher CO limit (0.11) than the one proposed for Holcomb (0.08). Accordingly, good combustion practice is BACT and the emission limit of 0.005 lb/mmBtu is appropriate considering the limits for the other pollutants.*

**Comment 69:**

The BACT limit for $SO_2$ from the auxiliary boilers is also too high. The boilers will fire natural gas, which should not result in $SO_2$ emissions above 0.0006 based on EPA's AP-42 factor. Redbud Energy LP and Pine Bluff Energy LLC have gas-fired boilers gas with permit limits of 0.0006 lb/mmBtu. The BASF Freeport Cogeneration Facility has an $SO_2$ permit limit of 0.0001 lb/mmBtu based on natural gas fuel. It must be assumed that BACT for the Holcomb Station units is at least this low.

***KDHE Response:***

*The Holcomb auxiliary boilers will be fired only with pipeline natural gas, a very low sulfur fuel, which inherently produces low $SO_2$ emissions. In addition, $SO_2$ emissions from the auxiliary boilers will also be limited by restricting the annual operation of the auxiliary boilers to 876 hours per year. The $SO_2$ emission estimates from the auxiliary boilers are based on the AP-42 emission factor of 0.0006 lb/mmBtu. This is the BACT emission rate as it is based on theoretical concentration of sulfur compounds in the gas stream and formation of $SO_2$ in the combustion process. There are no back-end control devices that can be utilized to further reduce $SO_2$ emissions. The final permit limit of 0.001 lb/mmBtu is the result of rounding this emission factor.*

**Comment 70:**

Each of the three proposed pulverized coal boilers at Holcomb Station will have an emergency diesel generator. Each of these generators will burn low-sulfur diesel fuel and will have a capacity of approximately 1,709 horsepower (1,200 kw). The proposed BACT limits for these units are based on diesel fuel. However, BACT must be based on clean fuels.

***KDHE Response:***

*The purpose of the emergency generators at the Holcomb site is to operate (other than during testing) during periods of unplanned internal plant electrical emergencies. Because of the critical nature of their operation, the emergency generators are designed to operate on a 100% independent and reliable source of fuel. The use of low-sulfur diesel fuel, stored on-site, meets this design requirement and BACT.*

**Startup, Shutdown, and Malfunction (SCC III O)**

**Comment 71:**

The draft permit unlawfully excludes periods of startup and shutdown. The draft permit purports to excuse periods of startup and shutdown from the BACT limits. This is unlawful for four reasons. First, a PSD permit must include stringent requirements to ensure compliance with the Clean Air Act during startup, shutdown and malfunction (SSM).

Second, the permit contains no emission limits applicable to the boilers during startup, shutdown or “malfunction.” This represents the worst-case scenario for emissions. These uncontrolled emissions must be used to model air impacts.

For both NAAQS and PSD increment compliance demonstrations, the **emissions rate** for the proposed new source or modification must reflect the maximum allowable operating conditions as expressed by the federally enforceable **emissions limit, operating level, and operating factor** for each applicable pollutant and averaging time.

The applicant and KDHE modeled based on BACT limits that do not apply at all times. The permit must either contain short-term emission limits that apply at all times, or the permit must be denied unless and until the applicant demonstrates compliance with NAAQS and increment during worst-case, uncontrolled conditions.

***KDHE Response:***

*Both the draft and the final permits contain BACT limits for VOC, CO, lead and sulfuric acid mist that include periods of startup, shutdown and malfunction.*

*The final permit includes a numeric limit for startup and shutdown events for* $NO_x$ *and a short term* $SO_2$ *limit that includes startup and shutdown. The short term* $SO_2$ *emission limit applies at all times and was selected to be consistent with the modeling for NAAQS and PSD increment consumption and ensure compliance with the same.*

*Mercury is not a PSD pollutant and is therefore not subject to BACT. Therefore, there is no requirement to establish a BACT limit that applies during startup, shutdown and malfunction.*

*PM and* $PM_{10}$ *emission limits exclude periods of startup, shutdown and malfunction. The final permit requires the facility to follow clearly defined work practices to minimize emissions during those periods.*

**Comment 72:**

There is no definition of “startup,” “shutdown,” or “malfunction” in the permit. The permit must define these periods and require monitoring and reporting sufficient to determine if such condition is occurring at any given moment.

***KDHE Response:***

*Startup and shutdown are defined differently for each pollutant due to variations in operating parameters for control equipment. Thus, startup and shutdown for* $NO_x$ *are defined in Air Emission Limitation 2.a, and for* $SO_2$ *in Air Emission Limitation 2.b in the permit (both draft and final). Startup and shutdown are defined in the final permit for* $PM/PM_{10}$*, and the definition is included in the final permit Air Emission Limitation 2.c.*

*Malfunction is defined at 40 CFR 60.2, and at K.A.R. 28-19-11. No restatement of definitions in the permit is necessary.*

*The permit (draft and final) defines what actions must be taken during malfunction events.*

**The Permit Limits are Too Lenient**

**Comment 73:**

The limits are much too lenient to constitute BACT, especially when periods of startup, shutdown and malfunction are excluded. Many other permitted facilities have lower emission limits than those proposed for Holcomb units 2-4. These other facilities do not exclude periods of startup, shutdown, and malfunction from the averaging times. The source must achieve lower emissions during all other periods of operation to achieve a permit limit that includes periods of startup, shutdown, and malfunction. The limits being proposed for Holcomb do not require the maximum degree of reduction during normal operating conditions.

***KDHE Response:***

*KDHE has included in the final permit Air Emission Limitations 2.a and b more stringent limits for $SO_2$ and $NO_x$, as well as short term BACT limits that apply during startup and shutdown. These changes in the final permit address the concept embodied in this comment.*

**Modeling (SCC III P)**

**Comment 74:**

The permit must ensure that the assumptions made for modeling are enforceable. In addition to the fact that worst-case conditions during startup, shutdown, and malfunction were not modeled, as noted above, there are a number of additional erroneous assumptions made as a part of the modeling for Holcomb 2-4. First, the modeling assumed that the auxiliary boilers and emergency generators were off. The Developers claim that the auxiliary boilers and emergency generators do not operate when the main boilers are operating. Therefore, these emission sources were not modeled. However, there is no enforceable permit condition prohibiting all emissions from the auxiliary boilers and emergency generators when there are any emissions from the main boilers. Indeed, these sources are likely to emit air pollutants when the main boilers are starting up, shutting down, or malfunctioning. The model must include worst-case conditions. This includes uncontrolled emissions from the boilers during startup, shutdown and malfunction and operation of the auxiliary boilers and diesel generators, unless there are enforceable permit conditions that prohibits these units from operating while there are any emissions from the main boilers.

***KDHE Response:***

*This commenter asserts that the modeling does not properly account for periods of startup and all "worst-case" scenarios during which the emergency generators could be operating during the startup of a unit. As indicated in the permit application, the main generating units utilize natural gas before solid fuel is introduced to the furnace. It is* *during this period of time that the individual auxiliary boiler may be used. Emissions of all pollutants, $SO_2$, $NO_x$, CO, and $PM_{10}$, from the steam generator, the auxiliary boiler, and the emergency generator combined, during any startup conditions, are well below the normal emission levels that are used in the air dispersion models. The auxiliary boiler or the emergency generator may, or may not, be necessary during startup. In addition, the emission of all criteria pollutants from an emergency generator, whether during testing, or other electrical emergency situation requiring this equipment to operate other than in startup is so very much less than the emissions from the main steam generator itself as to be unidentifiable in any modeling analysis.*

*This commenter also asserts that a specific condition is required in the air permit to prevent Sunflower from operating the emergency generators or the auxiliary boilers while the main boilers are operating. Such an additional permit limitation is unnecessary to accurately describe so as to cover all contingencies. The cost of operating both of these particular pieces of equipment will restrict their utilization to the manner indicated in the permit. As indicated, the auxiliary boilers are used to supply steam to various plant equipment requiring steam during outages or unit startup periods, and then only when steam is unavailable from another operating unit. Auxiliary boilers are not physically connected to any electric generator. Utilization of an auxiliary boiler in any other fashion, such as while the unit is itself operating, would be uneconomical. Similarly, the emergency generators are used only when the respective unit's electrical distribution system to the essential AC bus is unavailable. This may occur during a unit startup. Emergency generators are also tested at load for about 2 hours each month to assure that they would be reasonably available in an emergency situation. Actual emergency situations, requiring use of the emergency generator, are very rare. The emergency generator cannot be electrically connected to the grid. Operating either an auxiliary boiler or an emergency generator in a manner different from that described in the application would result in consuming a higher cost fuel without realizing any useful energy benefit. The main unit steam generator emissions used for both $NO_x$ and $SO_2$ dispersion modeling were greater than the expected permit conditions, and any emissions resulting from operation of either the auxiliary boiler or the emergency generator, when combined with expected main unit operations, will still be well below the dispersion modeling assumptions.*

**Comment 75:**

Modeling assumed that during atomizer change-out, or cleaning/flushing of lime slurry, scrubber efficiency would be decreased to one-half. Therefore, modeling for short-term (3-hour and 24-hour) $SO_2$ assumed 50% control, 0.5% coal, and only one 6-hour offline period of one scrubber unit during any 24-hour period. The modeling also assumed that there would never be emissions great than 0.1 lb/mmBtu, except during atomizer changeouts. None of these assumptions are justified because none are enforceable permit limits.

***KDHE Response:***

*As indicated in its response to Comment 8, KDHE has included a short-term emission limit in the final permit. No additional limits are needed to ensure compliance with the air modeling.*

**Comment 76:**

Emissions were modeled from material handling operations as if at a constant rate. This does not represent "worst case" conditions. Material handling operations—such as coal unloading—occur over a short period of a few hours and the hourly emissions are high at those times, while being minimal during other periods. Assuming a constant rate does not model the ambient air concentrations during short periods of very high emission rates. Modeling must be redone assuming "maximum allowable operating conditions."

***KDHE Response:***

*The air modeling already has been performed at the "maximum allowable operating conditions." The rates of coal unloading, coal handling, storage, and reclaim operations are all constrained by various processes. Unloading operations are constrained by the amount of coal that can physically be unloaded during the course of a day. This was discussed in the permit application, and PSD guidance allows for taking process limitations into account, which was appropriately done.*

*The "maximum allowable operating condition" has been modeled as described above. Because $PM_{10}$ is a 24-hour standard, not a 1-hour or 3-hour standard, this averaging methodology was appropriate. Even with a short-term (several hour) high emission rate due to maximum capacity, the other hours of the day see no utilization of the affected equipment.*

**Comment 77:**

The Draft Permit does not contain enforceable emission limits for a number of processes and fugitive sources. Nevertheless, the modeling completed by the applicant assumes various maximum hourly, monthly, and annual emission rates of particulate matter from material handling processes and fugitive sources. This is an error. The modeling must assume the maximum theoretical emissions during each relevant time period (i.e., hourly, monthly, and annual) unless an enforceable permit limit ensures a lower emission rate.

***KDHE Response:***

*The maximum theoretical emission rates must be used unless there is an appropriate physical or process limitation which would make their use impractical. Such restrictions are present at this site and have been incorporated into the air model. Issuing a permit limit on an inherent physical condition is not necessary, as any change in the process to increase throughput or emissions would require a permit modification.*

**Comment 78:**

The modeling assumes emissions in grams per second (or other mass-per-time-period increments). However, the emission limits for most emission sources in the permit are expressed in pounds per input, such as pounds per mmBtu heat input. To convert these input-based emission limits into mass-per-time-period units for modeling, KDHE and the applicant assumed a maximum hourly heat input and, therefore, maximum hourly emission rate. The maximum hourly heat input rate is not included in the permit as an enforceable limit. The permit limits must either be expressed in terms of total mass emissions per hour (i.e., pounds per hour), or an enforceable hourly heat input limit must be included in the permit before the permit limits can be relied on for modeling.

***KDHE Response:***

*The maximum hourly heat input to each boiler is included in the final permit. On page 4, in the "Air Emission Unit Technical Specifications" section, item 1 states, "Maximum design fuel input for each unit to be 6,501 million BTUs per hour (mmBtu/hr)".*

**Comment 79: The applicant-developers did not conduct the required preconstruction monitoring. (SCC III Q)**

It does not appear that any preconstruction ambient air monitoring was done for the project.

Under 40 C.F.R. 52.21(m)(1), the applicant is required to install and operate a series of ambient air quality monitors in the area around the proposed facility for at least twelve months prior to submitting its PSD permit application. To use ambient air monitoring data for a period less than twelve months, KDHE must make an on-the-record determination "that a complete and adequate analysis can be accomplished with monitoring data gathered over a period shorter than one year (but not less than 4 months)…"

***KDHE Response:***

*The federal regulation cited, 40 CFR 52.21(m)(1), does not require the applicant to perform monitoring. It is left to the discretion of the state agency as to where the monitoring data for the NAAQS analysis are acquired. As stated in the NSR Workshop Manual (page C.18):*

> *"… the assessment of existing ambient concentrations may be done by evaluating available monitoring data. It is generally preferable to use data collected within the area of concern; <u>however, the possibility of using measured concentrations from representative "regional" sites may be discussed with the permitting agency</u>." (emphasis added)*

*KDHE has the discretion to utilize regional data should local data not be present. In western Kansas, there is little industrial activity, and the regional airshed remains consistent across much of the state. The locations of the air monitoring stations and the distances to these stations were clearly identified. With this information in mind and due to the lack of sources of emissions in that area of the state, the regional monitors were adequate to utilize for this exercise. KDHE correctly used its regulatory authority to determine that neither site-specific air monitors nor monitoring data were required for this project.*

**PSD Increment and NAAQS Inventories (SCC III R.)**

**Comment 80:**

The PSD increment and NAAQS emissions inventories were deficient. The permit must be denied unless the applicant can demonstrate that the proposed project will not cause or contribute to an exceedance of NAAQS or a PSD increment when taking into account all area sources, including animal feeding operations.

***KDHE Response:***

*Air dispersion modeling to demonstrate compliance with the NAAQS and PSD Class II Increment was conducted in accordance with federal and state guidelines. Significant impact modeling, refined modeling (i.e., modeling conducted with additional NAAQS and increment consuming sources) was conducted for* $SO_2$ *and* $PM_{10}$*. All NAAQS and increment consuming sources within the allotted study area were used in the model. Compliance with all standards was demonstrated utilizing these sources.*

*The commenter contends generally that area sources need to be included in the models, and specifically, that all animal feedlot operations must be included in the air modeling to demonstrate compliance. A review of the documentation provided by the commenter indicates that EPA has published an emission factor for these activities. While an emission factor was found at the referenced location, it is not included in the standard EPA compendium of emission factors, AP-42. In fact, referring to the EPA's website, Section 9.4.1 of AP-42 is reserved for Cattle Feedlots. The following note is located in that section (emphasis added):*

*"This is a placeholder heading should EPA determine at some future date that development of a section is warranted."*

*As EPA indicates, no emission factors have been officially identified nor are they being developed at the current time. The information cited is from the Emission Inventory Improvement Program, for which funding was discontinued in 2003. The information has never been incorporated into AP-42. While emission information does exist, EPA has not promulgated regulations covering those sources. In addition, these activities are not required to report emissions to KDHE. Any and all emission estimates submitted are therefore speculative at best.*

*In summary, the NAAQS and Increment analyses were compiled using EPA and KDHE guidelines and fulfilled the requirements of the PSD modeling section.*

**Public Notice (SCC III S)**

**Comment 81:**

The public notice was deficient. A public notice for a PSD permit must provide specific information. One specific piece of information is "the portion of the applicable maximum allowable increment that is expected to be consumed by the source or modification." However, the notice falls well short of the mark for particulate matter increment.

***KDHE Response:***

*K.A.R. 28-19-350(k)(1) requires KDHE to state the portion of applicable maximum allowable increment consumed by the modification. KDHE considered this requirement for all pollutants by this source. It was determined that increment was consumed for $SO_2$ and $PM_{10}$.*

*For $SO_2$, it was determined that there was a clearly defined significant impact on the increment. Other than $PM_{10}$, no other pollutants consumed increment, and therefore were not included in the notice.*

*The notice states that the $PM_{10}$ exceedances were outside the significant impact area for the expansion project. These exceedances were due to facilities other than Holcomb. The reason was that the receptors experiencing the exceedances were in close proximity, probably on the property, of an existing facility. By the very fact that increment was not exceeded within the significant impact area of the expansion project infers that some increment was consumed by the expansion project but not so much as to cause an increment violation. A more specific description of the amount of increment consumed by $PM_{10}$ is not required.*

*In this case, the specific portion of increment consumed for $PM_{10}$ has no impact on emission limitations in the permit, actual emissions, BACT determinations for control equipment or air quality. The public notice met the requirements of Kansas regulations.*

**18 Month Construction Timeline (SCC III T)**

**Comment 82:**

The permit must retain a requirement that the applicant obtain a new BACT and modeling analysis for any emission source that does not commence construction within 18 months. The Draft Permit purports to require a new BACT determination and modeling analysis for any unit that does not commence construction within 18 months. This requirement must clarify that a new BACT determination and modeling analysis must be obtained for any emission source that does not commence construction within 18 months. As written, the provision could be misinterpreted to require a new BACT and modeling analysis only for the main boiler units, rather than any emission source that does not commence construction within the requisite time period. Furthermore, the permit, itself, must expire if the source does not commence construction within 18 months.

***KDHE Response:***

*See Response to Comment 7.*

## C. NATIONAL SIERRA CLUB SUPPLEMENTAL COMMENTS

### Startup, Shutdown and Malfunction

**Comment 83:**

Supplemental comments were provided related to the point that the permit must contain stringent requirements to ensure compliance with the CAA during periods of startup, shutdown, and malfunction.

***KDHE Response:***

*These comments were addressed in the final permit. See Response to Comment 71.*

### Ambient Air Monitoring

**Comment 84:**

The commenter notes that ambient air quality monitoring is required and that the ambient air quality and PSD increment inventories were deficient.

***KDHE Response:***

*See Response to Comments 79-80.*

### Carbon Monoxide

**Comment 85:**

Sierra Club's November 28, 2006, comments noted that the proposed CO limits are not BACT. Sierra Club further adds that low $NO_x$ emissions do not necessitate CO emissions above 0.10 lb/mmBtu. Several Midwest power plants have recently been retrofitted with low $NO_x$ burners and overfire air without an increase in CO emissions. Low CO emissions are possible concurrent to lower $NO_x$ emissions. The CO limits must be significantly reduced to comply with BACT.

***KDHE Response:***

*See Response to Comments 43-46. That analysis still prevails. KDHE is not aware of any PRB coal fired power plants that have been retrofitted to achieve CO emissions at or below 0.15 lb/mmBtu that achieve $NO_x$ emissions at or below 0.05 lb/mmBtu.*

**Sulfur Dioxide BACT**

**Comment 86:**

Sierra Club's November comments noted that BACT must be based upon wet scrubber technology. It also noted that, even assuming dry scrubber technology, the permit limits in the Draft Permit do not represent BACT. Since Sierra Club's comments, updated comprehensive industry reports on scrubbers have been released. These reports were prepared by Sargent & Lundy for the National Lime Association. The updated reports further support Sierra Club's November 2006 comments.

***KDHE Response:***

*See Response to Comments 18-30.*

## D. KANSAS SIERRA CLUB COMMENTS

**Preconstruction Monitoring**

**Comment 87:**

KDHE Erred in Not Requiring Pre-construction $PM_{10}$ Monitoring. Sunflower's Aermod modeling run showed that the 24-hour average $PM_{10}$ impact was more than twice the PSD monitoring de minimis level. Nonetheless Sunflower requested a waiver of pre-construction monitoring for $PM_{10}$ and KDHE agreed.

Holcomb is at or near the center of the largest concentration of cattle and swine confined animal feeding operations (CAFOs) in the state. CAFOs are known to be a major source of $PM_{10}$. KDHE has documented short term elevated levels of particulates near two beef feedlots at Larned, Ks. KDHE has measured significant levels of $PM_{10}$ about one mile downwind from a very large swine CAFO, including exceedances of the 150 ug/$m^3$ NAAQS for $PM_{10}$ on April 15, 2003 and April 18, 2004.

Distant CAFOs also contribute to fine particle concentrations that exist at the site. In addition direct fugitive emissions of $PM_{2.5}$ from beef feedlots are likely to travel longer distances and merge into the regional effect.

There is a history of CEMS exceedances of the opacity limit. Some of these were a result of planned maintenance activities. However such maintenance is performed every year and related emissions are legitimately considered existing emissions for the purpose of determining background air quality. On March 1, 2006 Sunflower was cited for a violation regarding excessive emissions from coal handling. Taken together there is a significant likelihood that actual $PM_{10}$ concentrations downwind of the site would exceed those that the applicant has estimated with its models. Had KDHE required a pre-construction monitor for $PM_{10}$ any additions to ambient concentrations from these exceedances would have been properly accounted for in the Holcomb units 2, 3 & 4 impact analyses.

Evidence is grossly inadequate to indicate that the $PM_{10}$ NAAQS standard has been achieved. The closest $PM_{10}$ monitoring site is in Dodge City some 54 miles away.

For the reasons given above, KDHE should deny the subject permit and require a preconstruction monitor for $PM_{10}$ and a re-filing of a new permit application at a later date.

***KDHE Response:***

*See Response to Comments 79-80. The commenter references high particulate matter monitor readings. The first occurred near Larned, Kansas. High readings were present, but were short term and did not result in any monitoring results exceeding the 24-hour standard. The second high particulate matter monitor readings occurred about one mile downwind from a very large swine CAFO. The high $PM_{10}$ readings on the two days in question, April 15, 2003 and April 18, 2004 were both the result of regional atmospheric conditions that resulted in very high winds in southwest Kansas and Colorado, New Mexico, Oklahoma and Texas. This was confirmed with satellite imagery and evaluation of other monitors in surrounding states. The exact conditions leading to these high concentrations were described in the KDHE report on the Seaboard facility monitoring program. The data were not representative of emissions associated with the CAFO but rather the impacts of multi-state weather systems.*

*The existing monitoring data used is representative of air quality in the Holcomb area and has reaffirmed our original decision to not require additional preconstruction $PM_{10}$ monitoring.*

**PSD Increment Inventories/Modeling**

**Comment 88:**

The applicant failed to include CAFO sources of $PM_{10}$ in increment modeling.

The applicant failed to include in its modeling the many large CAFO's within 50 km of the site which are important sources of $PM_{10}$.

> "In their public notice KDHE says that analysis showed $PM_{10}$ values would not contribute to any violation of ambient air standards but were above the Class II increment for $PM_{10}$ (30 ug/m$^3$). All these receptors that

> indicated the exceedance were outside of the significant impact area for the Holcomb expansion."

Since pre-construction monitoring was not required, and there is no valid substitute for such data, it cannot be concluded that the Holcomb expansion will not cause an exceedance of the $PM_{10}$ ambient air standard. The presence, nearby, of so many large CAFO sources of $PM_{10}$ make such an NAAQS exceedance a distinct possibility. We also note there is likely a large regional component of secondary fine particles associated with ammonia emissions from CAFOs as well as a significant component of $PM_{2.5}$ from direct emissions capable of traveling longer distances.

The inclusion of the CAFOs as $PM_{10}$ increment sources, some of which are new or expanded since PSD was last triggered in the area, would likely cause many more receptors to indicate an exceedance of the Class II increment for $PM_{10}$. *Since the CAFO effect would be widely distributed,* it is likely that some of these newly exceeding receptors would coincide with the significant impact area for the Holcomb expansion project.

For these reasons KDHE should deny the subject permit and require the applicant to re-- file air quality modeling information that includes CAFOs in the region as increment sources.

***KDHE Response:***

*See Comment 80.*

**Modeling**

**Comment 89:**

KDHE should require an AERMOD Modeling Run for the Reserve Pile $PM_{10}$ case.  he initial impact study using the ISC model showed a slightly higher $PM_{10}$ impact for the *reserve* coal pile case, i.e. 17.99 ug/m$^3$ for reserve as opposed to 17.33 ug/m$^3$ for the active pile. The AERMOD model analysis included a run only for the active pile case which generated an impact of 21.73 ug/m$^3$. In view of the previously cited inadequacies in the modeling procedure we are requesting that, in addition to including the CAFO sources, Sunflower also produce new modeling runs for both active and reserve pile cases.

***KDHE Response:***

*The facility originally used the ISCST model, which was the approved model at the time the application was submitted.  This model included modeling for the reserve pile.  After November, 2006, AERMOD became the approved model.  Modeling was initially conducted with ISCST for three units, then AERMOD for three units, and repeated a third time with AERMOD for two units (after conveying to KDHE that only two units would be* *built). KDHE has analyzed the results of both models and determined that the new AERMOD results have no impact on NAAQS or PSD increment beyond those in the original analysis.*

## E. FISH AND WILDLIFE SERVICE COMMENTS

### Class I Area Modeling

**Comment 90:**

In the public notice, it stated that a VISCREEN analysis was performed to determine whether there were any impacts to the Class I area. VISCREEN is a modeling tool that is used for sources located within 50 km of a Class I area. The appropriate model for long distance evaluations is CALPUFF. Fish and Wildlife Services (FWS) could not adequately review the impacts to the Class I area without the information that CALPUFF provides.

***KDHE Response:***

*The PSD regulations only require a full visibility impact analysis for sources within 100 kilometers of a Class I area. The closest Class I areas are Wichita Mountains and Great Sand Dunes, which are more than 400 km from the Holcomb facility.*

*At the request of KDHE and FWS, Sunflower has completed a Class I Visibility impact analysis using the CALPUFF modeling system. This analysis was conducted in consultation with KDHE, EPA Region 7, and FWS.*

*Two different methods were used to evaluate background visibility: Method 2 (all values expressed in % light extinction), and Method 6 (all values expressed in deciviews). The Method 2 results **did** indicate visibility impacts exceeding 5%. Method 6 assesses data on a 98$^{th}$ percentile basis, and predicted impacts to be below 0.5 deciviews.*

*CALPUFF is being used beyond the normally recommended maximum source receptor distance of 300 km, which can cause overestimation of visibility impacts. To address this problem, KDHE completed a Class I Visibility impact analysis using the CAMx modeling system, which does not have this distance limitation. The CAMx results indicated no visibility impacts exceeding 0.5 deciviews for the Wichita Mountains Class I Area in Oklahoma, Great Sand Dunes in Colorado, and all other Class I areas as well. This analysis is more representative than the CALPUFF analysis because of the large source receptor distance from Holcomb 2-3 to surrounding Class I areas (> 400 km).*

### Averaging Times for Limits and Modeling Input

**Comment 91:**

Sunflower used a long-term emission rate (30-day rolling average) as input to their Best Available Retrofit Technology (BART) modeling analyses. This is not appropriate for analyses that look at short-term averaging times such as visibility analyses, 3-hour and 24-hour increments, and short-term NAAQS standards. By using a long-term emission rate, the predicted visibility impacts are likely to have been underestimated. FWS' s experience indicates using short-term emission rates could increase Sunflower's predicted visibility impacts by at least 25%. The visibility modeling analysis should include 100% of the potential to emit emission limits. The current modeling analysis only included 95% of the estimated actual emission limits. As a result of the uncertainty of this modeling, we would request that the applicant provide a Class I visibility analysis as prescribed by December 2000 Federal Land Managers' Air Quality Related Values Work Group (FLAG) [http://www2.nature.nps.gov/air/Permits/flag/index.cfm]

Sunflower should propose and utilize BACT emission limits with averaging times in accordance with the standards, increments, and appropriate visibility thresholds. The PSD permit should include enforceable permit conditions to ensure that emissions are limited to those used as model inputs.

***KDHE Response:***

*KDHE has modified the final permit to include short term emission limits for $SO_2$. With input from FWS, appropriate modeling parameters, including emission estimates and/or limits were selected and used as model inputs for CAMx. The CAMx model demonstrated that the proposed Holcomb Units 2-3 will have no visibility impact exceeding 0.5 deciviews on Wichita Mountains Wilderness Area and other Class I areas.*

**Federal Land Manager Notification and Involvement**

**Comment 92:**

The FWS had concerns with the lack of notification to the federal land management agencies about the proposed project and cited federal regulations regarding state New Source Review permitting programs and indicated that for a state's rules to be approvable,

> "... the State plan must, in any review under §5l.l66 with respect to visibility protection and analyses, provide for:
>
> (1) Written notification of all affected Federal Land Managers of any proposed new major stationary source or major modification that may [emphasis added] affect visibility in any Federal Class I area. Such notification must be made in writing and include a copy of all information relevant to the permit application within 30 days of receipt of and at least 60 days prior to public hearing by the State on the application for permit to construct. Such notification must include an analysis of the anticipated impacts on visibility in any Federal Class I area,
>
> (2) Where the State requires or receives advance notification (e.g. early consultation with the source prior to submission of the application or notification of intent to monitor under § 51.166) of a

permit application of a source that may affect visibility the State must notify all affected Federal Land Managers within 30 days of such advance notification, and

(3) Consideration of any analysis performed by the Federal Land Manager, provided within 30 days of the notification and analysis required by paragraph (a)(1) of this section, that such proposed new major stationary source or major modification may have an adverse impact on visibility in any Federal Class I area. Where the State finds that such an analysis does not demonstrate to the satisfaction of the State that an adverse impact will result in the Federal Class I area, the State must, in the notice of public hearing, either explain its decision or give notice as to where the explanation can be obtained [40 CFR 51.307(a) (1) thru (3)]."

According to the FWS, the required notification did not occur. FWS encouraged KDHE to notify the Federal Land Management agencies of permit actions that may impact Class I Areas and not use a "100 km bright line cutoff' which potentially restricts FWS's ability to carry out the charge to protect the air quality and air quality related values at the Class I areas. According to FWS, experience has shown that there have been many proposed projects over 100 km that have had significant impact to Class-I areas.

FWS proposed the development of an agreement to provide for timely and reasonable federal land management agency involvement in KDHE's permitting process.

***KDHE Response:***

*As clearly stated in 40 CFR 51.307(a)(1) through (3), KDHE was not required to notify FWS of this permit application. KHDE appreciates FWS willingness to work with the agency throughout the modeling process. KDHE has submitted a draft agreement to FWS to provide for timely Federal Land Manager involvement in KDHE's air permitting process.*

## F. ATTORNEYS GENERAL COMMENTS

**Comment 93:**

The Attorneys General of the States of California, Connecticut, Delaware, Maine, New York, Rhode Island, Vermont, and Wisconsin jointly submitted comments requesting KDHE not to issue a permit for the proposed plant unless Sunflower designs the plant in a way that minimizes the generation of $CO_2$ emissions and/or allows capture of such emissions.

The states listed in this letter are concerned about global warming, and have made the reduction of $CO_2$ emissions a priority through legislation in their states. Issuance of this permit would increase $CO_2$ emissions, and undermine efforts being undertaken by these states to address global warming.

The states encourage Kansas to explore alternatives to satisfy its need for energy, including renewable energy sources and IGCC.  The BACT analysis for Holcomb 2-3 should include IGCC, and should also consider environmental impacts of $CO_2$.

***KDHE Response:***

*There are no provisions to regulate carbon dioxide in PSD permits.  These comments were referred to Secretary Bremby for further policy considerations.*

*See Response to Public Comments, Section IV, Comments F and G, and Response to Comments from Organizations, Section V, Comments 10 and 12.*