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

Kansas Department of Health and Environment
Bureau of Air

December 2010

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List of Acronyms

Acronym	Description
AAQIR	Ambient Air Quality Impact Report
ACC	Air Cooled Condenser
ACCCE	American Coalition for Clean Coal Electricity
ACI	Activated Carbon Injection
ADEQ	Arizona Department of Air Quality
AEO	Annual Energy Output
AEP	American Electric Power
AERMOD	AMS/EPA Regulatory Model
AHPC	Advanced Hybrid Particulate Collector
AMI	AMI Environmental
AMS	American Meteorological Society
ANGA	America's Natural Gas Alliance
AP-42	EPA Compilation of Air Pollutant Emission Factors
AQIA	Air Quality Impact Analysis
ARM	Ambient Ratio Method
B&V	Black and Veatch
BACT	Best Available Control Technology
BAPC	Bureau of Air Pollution Control
BME	Board of Minerals and Environment
BOA	Bureau of Air
Btu	British Thermal Unit
BWM	Bureau of Waste Management
CAA	Federal Clean Air Act
CAAA	Clean Air Act Amendments of 1990
CALPUFF	California Puff
CAMx	Comprehensive Air Quality Model with Extensions
CAMD	Clean Air Markets Division
CASAC	Clean Air Science Advisory Committee
CCP	Coal Combustion Products
CCS	CO_2 Capture and Storage
CDS	Circulating Dry Scrubber
CEA	Clean Energy Action
CEMS	Continuous Emission Monitor System
CENRAP	Central Regional Air Planning Association
CFB	Circulating Fluidized Bed
CEP	Climate and Energy Project

List of Acronyms

Acronym	Description
CFR	Code of Federal Regulations
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COHPAC	Compact Hybrid Particulate Collector
COM	Continuous Opacity Monitor
CPM	Condensable Particulate Matter
CUECOST	Coal Utility Environmental Cost
CURC	Coal Utilization Research Council
DCFS	Double Contact Flow Scrubber
DFP	Diesel Fire Pump
dv	Deciview
DWR	Division of Water Resources
DOE	Department of Energy
EAB	Environmental Appeals Board
EGU	Electrical Generating Unit
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
EVA	Energy Ventures Analysis Inc.
FERC	Federal Energy Regulatory Commission
FF	Fabric Filter
FGD	Flue Gas Desulfurization
FIP	Federal Implementation Plan
FLM	Federal Land Manager
FR	Federal Register
FSI	Furnace Sorbent Injection
FWS	Fish and Wildlife Service
GHG	Greenhouse Gas
GPACE	Great Plains Alliance for Clean Energy
GSDNP	Great Sands Dune National Park
GWh	Gigawatt Hour
H1	Holcomb Unit 1 Electric Steam Generator
H2	Holcomb Unit 2 Electric Steam Generator
H3	Holcomb Unit 3 Electric Steam Generator

List of Acronyms

Acronym	Description
H_2O_2	Hydrogen Peroxide
H_2SO_4	Sulfuric Acid
HAP	Hazardous Air Pollutant
HCl	Hydrochloric Acid
HF	Hydrofluoric Acid
Hg	Mercury
ICR	Information Collection Request
IEPA	Illinois Environmental Protection Agency
IGCC	Integrated Gasification Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
IPP	Intermountain Power Project
ISCST3	Industrial Source Complex Short Term Model
KAR	Kansas air Quality Regulations
KAQA	Kansas Air Quality Act
KCC	Kansas Corporation Commission
KDA	Kansas Department of Agriculture
KDAQ	Kentucky Division for Air Quality
KDHE	Kansas Department of Health and Environment
KSA	Kansas Statutes Annotated
KWh	Kilowatt Hours
LAER	Lowest Achievable Emission Rate
Lb	Pound
LCOE	Levelized Cost of Electricity
LGTI	Louisiana Gasification Technology, Inc.
LNB	Low NO_x Burner
LSD	Lime Spray Dryer
LSFO	Limestone Forced Oxidation
MACT	Maximum Achievable Control Technology
mcf	One Thousand Cubic Feet
MeHg	Methylmercury
MEL	Magnesium Enhanced Lime
MHI	Mitsubishi Heavy Industries
mmBtu	Million Btu
MSA	Metropolitan Statistical Area
MW	Megawatt
MWh	Megawatt Hours

List of Acronyms

Acronym	Description
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standard for Hazardous Air Pollutants
NETL	National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle
NO	Nitric Oxide
NO_X	Oxides of Nitrogen
NO_2	Nitrogen Dioxide
NO_2EQUIL	NO2/NOx Equilibrium Ratio
N_2O	Nitrous Oxide
NPDES	National Pollutant Discharge Elimination System (Federal Water Pollution Control Rules)
NSPS	New Source Performance Standard
NSR	New Source Review
NWR	National Wildlife Refuge
NWS	National Weather Service
O_2	Oxygen
O_3	Ozone
OEMs	Original Equipment Manufacturer
OFA	Over-Fire Air
OLM	Ozone Limiting Method
OTM	Other Test Method
PAC	Powdered Activated Carbon
PADEP	Pennsylvania Department of Environmental Protection
PC	Pulverized Coal
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 2.5 microns
PC	Pulverized Coal
PPS	Polyphenylene Sulfide
PRB	Power River Basin
PSD	Prevention of Significant Deterioration
PTE	Potential-To-Emit
PV	Photovoltaic

List of Acronyms

Acronym	Description
PVMRM	Plume Volume Molar Ratio Method
RACT	Reasonable Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
ReACT	Regenerative Activated Coke Technology
RTO	Regenerative Thermal Oxidizer
RTR	Risk and Technology Review
SAM	Sulfuric Acid Mist
SCC	Sierra Club Comment
SCPC	Supercritical Pulverized Coal
SCR	Selective Catalytic Reduction
SDA	Spray Dryer Absorber
SIBC	Sunflower Integrated Bioenergy Center
SIL	Significant Impact Level
SIP	State Implementation Plan
SLAMs	State and Local Air Monitoring Stations
SMC	Significant Monitoring Concentrations
SMPS	Switched-Mode-Power-Supply
SNCR	Selective Non Catalytic Reduction
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
SOFA	Separated Over-Fire Air
SPMs	Special Purpose Monitors
STMS	Sorbent Trap Monitoring System
TDD	Technical Development Document
TCEQ	Texas Commission on Environmental Quality
Tcf	Trillion Cubic Feet
TR	Transformer-Rectifier
TXI	A Dallas, Texas based Energy Company
TXU	Texas Industries, Inc., a major producer of steel and cement/concrete products for construction
TWh	Terawatt-Hours
USC	United States Code
USGS	United States Geological Service
VISCREEN	Plume Visual Impact Screening Model
VOC	Volatile Organic Compound
WDOE	Washington Department of Ecology

I. KDHE RECOMMENDATION

The Kansas Department of Health and Environment (KDHE) Bureau of Air (BOA) recommends the issuance of an Air Quality Prevention of Significant Deterioration (PSD) Construction Permit to Sunflower Electric Power Corporation (Sunflower) for construction of one (1) new 895 megawatt (MW) supercritical pulverized coal (PC) fired steam generating unit and associated ancillary equipment (Holcomb expansion) at their generating station located in Holcomb, Kansas.

The construction permit issued for the project identifies the applicable rules governing emissions from the plant and establishes enforceable limitations on its emissions. The permit also establishes appropriate compliance procedures, including requirements for emissions testing, continuous emission monitoring, recordkeeping, and reporting. 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 properly controlled.

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

http://www.kdheks.gov/bar/sunflower/sunflower.html

or contact: (785) 296-6423.

II. PROJECT DESCRIPTION

The original permit application was submitted to the Kansas Department of Health and Environment (KDHE) in February 2006. The application was originally for three 700 MW coal fired generating units, and subsequently was reduced to two 700 MW coal fired generating units. The original permit was denied October 18, 2007. An agreement between Governor Mark Parkinson and Sunflower Electric Power Corporation was signed on May 4, 2009. The agreement was for the purpose of facilitating the timely issuance of a final PSD permit for the construction of one 895 MW pulverized coal super critical generating unit. Since there were significant design changes, additional application material was submitted December 16, 2009, with additional updates submitted January 13, 2010 through August, 2010. Modeling data and analyses were replaced in submittals in August 2010.

Sunflower plans to modify a generating facility located in Holcomb, Finney County, Kansas. The generating station will install Holcomb Unit 2, a supercritical 895 megawatt (MW) (8,700 mmBtu/hr heat input) pulverized coal (PC) fired boiler. Additional coal, lime, and ash handling equipment will be added to the existing equipment to accommodate additional throughput. A new cooling tower, a natural gas fired auxiliary boiler, an emergency generator, and a diesel fire pump will be added. The Holcomb Unit 2 boiler will fire Powder River Basin (PRB) sub-bituminous coal, low sulfur bituminous coal as primary fuel and natural gas as a startup fuel.

III. KDHE PERMIT CONSIDERATIONS

The new generating unit proposed by Sunflower is considered a major modification of a major stationary source because one or more of the PSD regulated air pollutants from the proposed project 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 monuments, 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. Effects of New Federal Regulations

KDHE is the recognized permitting authority for PSD determinations pursuant to a state implementation plan (SIP) published at 40 C.F.R. §§ 52.870 – 52.884 (7-1-09 Edition). The SIP defines the rules and regulations that apply to the proposed project.

During the pendency of the initial Sunflower permit application, EPA promulgated revised $PM_{2.5}$ and PM_{10} NAAQS, effective December 18, 2006. For states with EPA-approved PSD

programs, EPA left in place its PM_{10} Surrogate Policy (Seitz, October 23, 1997) allowing the use of PM_{10} as a surrogate for $PM_{2.5}$.

On May 16, 2008, EPA promulgated the Clean Air Fine Particle Implementation Rule to implement the $PM_{2.5}$ NAAQS. See 73 FR 28321. SIP states have three years from the date of publication to revise their SIPs for EPA approval. See 73 FR 28340-41.

Since the January 13, 2010 update to the Sunflower permit application, EPA has promulgated and/or published the following, which are new federal regulatory requirements and/or recommendations for a facility seeking a PSD permit:

Table 1. Federal Regulatory Changes Since January 13, 2010

Rulemaking Date	Effective Date	Citation	EPA Action
Feb. 11, 2010	No final rule published	75 FR 6827	Proposed to repeal the PM_{10} Surrogate Policy (Seitz, October 23, 1997) allowing the use of PM_{10} as a surrogate for $PM_{2.5}$
Feb. 9, 2010	Apr. 12, 2010	75 FR 6474	Final Rule: Revised 1-hour NO_2 NAAQS
Feb. 26, 2010			Guidance Document: Model Clearinghouse Review of Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS
Mar. 23, 2010			Guidance Document: Modeling Procedures for Demonstrating compliance with $PM_{2.5}$ NAAQS
June 2, 2010	Aug. 2, 2010*	75 FR 31514	Proposed Tailoring Rule for GHGs
June 29, 2010			Guidance Document: Guidance Concerning the Implementation of the 1-hour NO_2 NAAQS for the PSD Program
June 22, 2010	Aug. 23, 2010	75 FR 35520	Effective date of revised 1-hour SO_2 NAAQS
Aug. 23, 2010			Guidance Document: Guidance Concerning the Implementation of the 1-hour SO_2 NAAQS for the PSD Program
Aug. 24, 2010	No final rule published	75 FR 51960	Proposed rule to implement 8-hour ozone NAAQS
Sept. 2, 2010	No final rule published	75 FR 53892	Proposed SIP Call for Tailoring Rule
Sept. 2, 2010	No final rule published	75 FR 55883	Proposed FIP for Tailoring Rule
Oct. 20, 2010	Dec. 20, 2010	75 FR 64864	EPA published a final rule defining PSD increments, significant impact levels, and the significant monitoring concentration for $PM_{2.5}$
Dec. 13, 2010	Dec. 13, 2010	75 FR 77698	Final SIP Call for Tailoring Rule

*Final rule establishes a take-effect date of Jan. 2, 2011.

Clean Air Act (CAA) § 110 obligates SIP states to adopt and submit to EPA a revised SIP to implement, maintain, and enforce new or revised primary NAAQS. Under CAA § 110, Kansas has three years from the date of the NAAQS publication in which to complete its SIP submission, unless the EPA Administrator prescribes a shorter period. KDHE has not missed the SIP submission deadlines for any of the described federal rules. Until Kansas submits the

EPA Administrator approves a revised SIP submittal, the approved Kansas SIP continues to have full force and effect. General Motors Corporation v. United States, 496 U.S. 530 (1990).

Even though the CAA does not require KDHE to immediately revise its SIP or implement the new regulatory requirements, KDHE's analysis did include review of all EPA guidance available at the time of decision making, modeling specifically directed at the new requirements, modifying permit conditions to address new requirements, and considering impact of the new requirements on other parts of the application.

As a result, KDHE does not expect the proposed project to cause or contribute to any NAAQS or increment violation, including the new standards.

B. 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 unit, the increase in potential-to-emit is above the PSD significance level for NO_x, SO_2, CO, $PM/PM_{10}/PM_{2.5}$, sulfuric acid mist, and VOCs and was reviewed under the PSD regulations. Total fluorides and lead are below the PSD significance levels.

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

1. 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).

2. For carbon monoxide (CO), BACT is good combustion practices.

3. For sulfur dioxide (SO_2), the steam generators shall use a dry flue gas desulfurization (dry FGD) system and low sulfur coal.

4. For volatile organic compounds (VOC), BACT is good combustion practices.

5. For particulate matter (PM), BACT is a fabric filter.

6. For filterable particulate matter with aerodynamic diameter less than or equal to 10 microns (PM_{10}), BACT is a fabric filter.

7. For filterable particulate matter less than 2.5 microns ($PM_{2.5}$), BACT is a fabric filter.

8. For total sulfuric acid (H_2SO_4), BACT is a dry FGD.

C. 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 AERMOD modeling system, Version 09292, was used to determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period.

The dispersion modeling analysis for a PSD project typically involves two distinct phases. The first phase is the preliminary analysis, or significant impact analysis, which determines if the applicant can forego further air quality analysis for a particular pollutant with respect to the NAAQS and PSD increments. If the SIL is exceeded, the second phase is triggered. The second phase is the cumulative analysis for the NAAQS and applicable PSD increments. This analysis involves a multi-source comprehensive assessment of air quality impacts.

Significant Impact Levels (SILs) are numeric values normally derived and published by the U.S. Environmental Protection Agency (EPA), and adopted in state regulations. SILs are used to evaluate the impact of a proposed major source or modification on the NAAQS or PSD increment. The EPA and KDHE consider a source whose individual impact falls below a SIL to have a de minimis impact on air quality concentrations. Consequently, SILs are used in the preliminary phase and are an inherent part of the modeling analysis to determine if the applicant of a PSD project that wishes to locate in an attainment or unclassifiable area must conduct a cumulative analysis.

During the pendency of the Sunflower PSD permit application, EPA has promulgated revised NO_2 and SO_2 NAAQS, and $PM_{2.5}$ NAAQS and SILs, and proposed a revised ozone NAAQS. The new 1-hour NO_2 NAAQS standard was published in the Federal Register on February 9, 2010, with an effective date of April 12, 2010. The new 1-hour SO_2 NAAQS standard was published in the Federal Register on June 22, 2010, and became effective August 23, 2010. The recent NAAQS values published by EPA have been issued without the appropriate SILs, although they are an inherent part of the modeling analysis. In the absence of EPA issued final SILs, KDHE and other permitting agencies have developed interim SILs for 1-hour NO_2 NAAQS, 1-hour SO_2 NAAQS, 24-hour $PM_{2.5}$ NAAQS, and annual $PM_{2.5}$ NAAQS. The KDHE-established interim SILs are to be valid until the EPA promulgated SILs are effective and adopted in Kansas air quality regulations. On October 20, 2010, the EPA published new

SIL values in the Federal Register for 24-hour and annual $PM_{2.5}$ NAAQS, which will become effective December 20, 2010. However, these $PM_{2.5}$ SILs are not yet effective in Kansas since they have not been incorporated to the Kansas air regulations.

Preliminary Analysis: The modeled impacts for the proposed facility fall below the modeling significance thresholds for annual NO_2, 8-hour CO, 1-hour CO, annual SO_2, annual PM_{10} (standard has been revoked), annual $PM_{2.5}$, and 24-hour $PM_{2.5}$.

Cumulative Analysis: The full impact analysis included the combined impact of the proposed project, nearby sources, and background concentrations. A full impact analysis was conducted for NAAQS and PSD increments for each pollutant and averaging period for which the modeling significance threshold was exceeded. Thus, a full impact analysis was performed for the 24-hour, 3-hour, and 1-hour SO_2; the 1-hr NO_2 (cumulative analysis only was performed; no preliminary); and the 24-hour PM_{10}. The 1-hr NO_2 and SO_2 increment analyses were not performed because no increments have been established by EPA.

NAAQS exceedances were modeled in the 1-hour NO_2 compliance demonstration. An analysis was conducted for each receptor for which there was an exceedance. The results of the analyses indicated that for all modeled exceedances, the proposed project contributes less than the SIL and therefore does not cause or contribute to any modeled exceedance.

NAAQS exceedances were modeled in the 1-hour SO_2 compliance demonstration. An analysis was conducted for each receptor for which there was an exceedance. The results of the analyses indicated that for all modeled exceedances, the proposed project has impacts less than the SIL and therefore does not cause or contribute to any modeled exceedance.

The full impact analyses indicated that concentration levels of all pollutants resulting from the proposed project, when combined with other sources, would not cause or contribute to an exceedance of the NAAQS.

The increment analyses indicated that concentration levels of all pollutants resulting from the proposed project, alone and when combined with other increment consuming sources, would comply with PSD Class II increments.

D. 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

The PSD regulations require the applicant to provide an analysis of impairment to visibility that will occur as a result of the source and growth associated with the source

[40 CFR 52.21(o)(1)]. There are no Federal Class I areas located within 100 km of the proposed facility. The nearest Federal Class I Area is the Great Sand Dunes National Park, nearly 400 km west of the proposed facility. Wichita Mountains National Wildlife Refuge is slightly more than 400 km southeast of the proposed facility.

At the request of KDHE and US Fish and Wildlife Services (FWS), the applicant completed a Class I Visibility Impact Analysis using the CALPUFF modeling system. This analysis was done when the application contained two 700 MW steam generating units. The visibility impacts of the project, now reduced to 895 MW, will be lower than those previously determined. The analysis included Great Sand Dunes and Wichita Mountains Class I areas.

CALPUFF was used beyond the normally recommended maximum source receptor distance of 300 km, which can cause overestimation of visibility impacts. 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 98th percentile basis, and predicted impacts to be below 0.5 deciviews.

To address the distance limitations with CALPUFF, 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).

The 2007 CAMx modeling analysis described above was conducted for three 700 MW units. Impacts will be lower for the single 895 MW unit currently proposed at the same location.

Per direction from KDHE, Sunflower conducted an analysis of the Scott Lake Class II area, located approximately 80 km to the north of the facility was performed. The visibility analysis was performed in accordance with the guidelines set forth in EPA-450/4-88-015, Workbook for Plume Visual Impact Screening and Analysis. The screening analysis indicated that some of the Class I screening criteria were exceeded. No criteria have been established for Class II areas.

Analysis of the City of Holcomb was also performed, using a distance of 7 km to the edge of the city and 8 km for the far side of the city. Procedures and inputs used in the Scott Lake analysis were followed. The screening analysis indicates that some of the Class I screening criteria were exceeded. No criteria have been established for Class II areas.

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 soils 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.

E. Public Involvement

Following its review of Sunflower's application, the KDHE BOA 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 and comment from July 1, 2010 through August 15, 2010. Three public hearings were held to receive oral and written comments. The first public hearing was held in Overland Park, Kansas on Monday, August 2, 2010. The second public hearing was held in Salina, Kansas on Wednesday, August 4, 2010. The third public hearing was held in Garden City, Kansas on Thursday, August 5, 2010.

Shortly before the scheduled hearings, an error in the modeling data was discovered in the Sunflower construction permit application. As a result, Sunflower revised and resubmitted the modeling data for review. KDHE held an additional public comment period between September 23, 2010 and October 23, 2010. A fourth public hearing was held in Topeka, Kansas on October 25, 2010.

The hearings were conducted in order to obtain oral and written comments concerning the proposed permit. The total number of verbal comments submitted at the four public hearings was 242. In addition to the verbal comments received during the public hearings, there were 1,331 personal emails, 1,553 form e-mails, 2,546 form letters or postcards, 133 personal letters, 20 organizational emails, 47 organizational letters, and 4 phone comments for a total of 5,634 written, e-mailed and phoned comments submitted to the Department during the public notice periods. The total number of verbal and written comments submitted was 5,876.

KDHE is responding to general concerns and comments from individuals in Section IV and is responding to technical comments from organizations and individuals in Section V. Due to the extensive length of some of the technical comment documents from organizations, KDHE has summarized many of them in this response. All comments can be viewed upon request by contacting KDHE at 785-296-6423.

IV. RESPONSE TO GENERAL PUBLIC COMMENTS

(Note: When referring back to General Public Comments, they will be referenced by their comment letter, such as Comment A).

Comment A:

Several Comments Regarding Energy; There Should Be More Energy Efficiency; There Should be Utilization of Cleaner Energy; There Should be Usage of Renewable Energy; There should be more Energy Conservation; This Additional Energy is not Needed for Kansas.

KDHE Response:

The comments address Sunflower's basic technology selection. KDHE lacks statutory or regulatory authority to redefine the source that Sunflower seeks to permit. There are no current federal provisions to regulate energy efficiency, renewable energy and energy conservation practices in PSD permits. K.S.A. 2009 Supp. 65-3005(b)(1) precludes KDHE from promulgating regulations more stringent than federal requirements without approval from the Kansas legislature.

Sunflower chose a supercritical pulverized coal-fired steam generator as the design for H2 to meet the needs of the project participants. Sunflower addresses the decision to propose construction of a supercritical pulverized coal-fired steam generator as opposed to a simple or combined cycle natural gas unit in Section 1.3.9 of Sunflower's Application, as follows:

> *The long-term fuel cost associated with such resources makes energy supplied by them too expensive for the base-load needs of the Participants. These generation resources are more suitable for peaking and intermediate load applications, and Sunflower already operates more than 600 MW of this type resource to meet the peaking and intermediate load requirements of its owners.*

KDHE has applied all existing federal and state regulations regarding control of particulate matter, hazardous air pollutants, mercury and lead and incorporated the applicable requirements into the permit.

Comment B:

Concerns about the Effect of the Plant on Energy Rates

KDHE Response:

There are no current federal provisions to regulate energy rates in PSD permits. K.S.A. 2009 Supp. 65-3005(b) (1) precludes KDHE from promulgating regulations more stringent than federal requirements without approval from the Kansas legislature.

Comment C:

Water Consumption and Conservation Should be Addressed

KDHE Response:

KDHE does not have regulatory authority over matters related to water supply and usage. The Kansas Department of Agriculture (KDA), Division of Water Resources (DWR) is responsible for regulating the use of water in Kansas. Please refer to KDA Fact Sheet entitled: "Water for Sunflower Electric's Proposed Expansion" located at the following website:

http://www.ksda.gov/includes/document_center/dwr/Publications/SunflowerExpansion.pdf

Comment D:

General Request that KDHE Should or Should Not Issue the Permit

KDHE Response:

KDHE appreciates the interest shown from all participants during the course of the public process for this air permit. KDHE must follow all federal and state requirements when reviewing the application and making a determination on whether or not to issue a permit. When a source submits an air permit application proposing the type of facility that is to be built, it is KDHE's responsibility to determine if the facility utilized the Best Applicable Control Technology (BACT) for reducing emissions and met all other applicable federal and state air rules and regulations. If the application does meet all requirements, KDHE must issue the permit, as required by law.

Comment E:

Comments Regarding Jobs and the Economy

KDHE Response:

There are no current state or federal provisions to regulate the impact on the types of jobs or economic advantages/disadvantages in PSD permits. K.S.A. 2009 Supp. 65-3005(b)(1) precludes KDHE from promulgating regulations more stringent than federal requirements without approval from the Kansas legislature. Economic considerations are only taken into account when the applicant is conducting the BACT analysis to determine if the cost of the control option(s) will cause adverse economic impact to the facility. The contribution to the local/regional economy is not an accepted justification when determining BACT.

Comment F:

General Concerns Regarding Health Effects from Pollution

KDHE Response:

A critical element of the air permitting process and 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. Finney County is in attainment for the NAAQS,

which is why the PSD permitting process is applicable to Holcomb 2. As part of its application, Sunflower provided information demonstrating that air emissions from Holcomb 2 would not cause or contribute to an exceedance of any NAAQS.

Comment G:

Concerns Regarding Health Effects from Mercury and other Hazardous Air Pollutants

KDHE Response:

Currently, there are no specific EPA mercury limits. EPA's New Source Performance Standard (NSPS) limit of 0.097 lb/GWh was vacated and is no longer in effect. Until EPA develops a new mercury standard, states must issue case-by-case mercury standards for EGUs if they have the potential to emit 10 tons or more of an individual hazardous air pollutant (HAP) or 25 tons or more of a combination of HAPs. This permit contains enforceable permit requirements (such as emission limits and coal testing) to ensure Sunflower's emissions remain below these levels. Therefore the case-by case MACT requirement is not applicable. However, Sunflower has signed an agreement stating that the combined mercury emission levels from H1 and H2 will not increase from the current emission level of H1 and that the permit will include a mercury limit of 0.020 lb/GWh forH2, which is an 80 percent reduction from the previous NSPS limit .

Mercury and other pollutants known as hazardous air pollutants (HAPs) are addressed in federal regulations known as the National Emission Standards for Hazardous Air Pollutants (NESHAP) program through the MACT Standards. After these standards are in place, the Risk and Technology Review (RTR), formerly known as the residual risk program takes effect to evaluate the remaining health and environmental risks from HAPs. Section 112(f) of the Clean Air Act (CAA) requires EPA to promulgate standards beyond MACT when necessary to provide an ample margin of safety to protect the public. At this time, several industrial source categories are being evaluated for residual risks. The CAA requires EPA to set any required standards no later than 8 years after the MACT standard was promulgated. Information can be found at the EPA website:
http://www.epa.gov/ttn/atw/rrisk/rtrpg.html

EPA has proposed the National Emission Standards for Major Sources, Industrial/Commercial/Institutional Boilers and Process Heaters, 40 CFR Part 63 Subpart DDDDD, and the National Emission Standards for Area Sources: Industrial/Commercial/Institutional Boilers, 40 CFR Part 63 Subpart JJJJJJ. Sunflower will be required to meet applicable new federal requirements when they become finalized

Comment H:

General Concerns Regarding Pollutant Levels are too high.

KDHE Response:
Please see Public Comments F and G. In addition to meeting the NAAQS requirements, the air dispersion modeling results submitted for the estimated emissions showed there would be no detrimental effects on soils or vegetation. Sunflower also signed an agreement to reduce emission levels for NO_x, SO_2, and Mercury from this unit.

Comment I:

Carbon Dioxide (CO_2) Emissions are Too High

KDHE Response:

For purposes of KDHE's responses in this document, any reference to CO_2 is intended to include all greenhouse gases (GHGs). The term GHGs includes: carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), and the fluorinated gases, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

There is no federal law currently limiting CO_2 emissions in PSD permits. K.S.A) 2009 Supp. 65-3005(b)(1) precludes KDHE from promulgating regulations more stringent than federal requirements without prior approval from the Kansas legislature.

Comment J:

Comment That There were No Particulate Limits in the Permit

KDHE Response:

The permit does include Particulate limits.

Comment K:

Comments Regarding the Length of The Public Comment Period Should be Extended.

KDHE Response:

KDHE has complied with all federal and state requirements for public review and comment of this project. Due to the large amount of interest, a 45-day public notice period and 3 public hearings were held across the state in August. An additional 30-day notice was provided due to the discovery of a modeling inconsistency and a fourth public hearing was held to ensure the public could comment on all aspects of the proposed permit.

Comment L:

Comments and Concerns Regarding Solid Waste, including Large Amounts/Radioactivity of Coal Ash.

KDHE Response:

The KDHE BOA does not have regulatory authority over solid waste/coal ash disposal requirements; therefore, these items are not addressed in the air permit. The KDHE Bureau of Waste Management (BWM) regulates solid wastes in Kansas and Containment/disposal of coal ash is regulated by the KDHE Bureau of Waste Management (BWM) and is outside the scope of this permit. The management of coal combustion residuals that will be generated in connection with H2 operations will be subject to the terms and conditions of a permit issued by KDHE BWM to Sunflower in accordance with applicable laws and regulations.

V. RESPONSE TO TECHNICAL COMMENTS FROM ORGANIZATIONS

(Note: When referring back to technical comments from organizations and individuals, they will be referenced by their <u>comment number, such as Comment 1</u>).

A. EPA REGION 7 COMMENTS (Comments 1-30)

Comment 1:

Options that maximize the energy efficiency of the facility ought to be considered in the BACT analysis and decision. As the thermal efficiency of a coal-fired boiler is increased, less coal is burned per kilowatt-hour (kWh) generated, and there is a corresponding decrease in air emissions such as NO_X, SO_2, and greenhouse gasses. For example, ultra-supercritical boilers can operate at higher efficiencies compared to supercritical boilers. Although currently there are no operating ultra-supercritical boilers in the United States, the technology is used widely for new units in other parts of the world. The BACT record does not include any analysis evaluating ultra-supercritical boiler technology.

KDHE Response:

The commenter notes that there are currently no operating ultra-supercritical boilers in the United States. There is one publicized ultra-supercritical facility under construction in the U.S., the John Turk unit in Arkansas, scheduled to begin operations in 2012. This lack of operating history by U.S. utilities is a key factor in the determination that a supercritical boiler represents BACT for this permit.

The term "ultra-supercritical" is associated with a further increase in steam pressures and temperatures to gain higher cycle efficiencies. The higher pressures and temperatures associated with the supercritical steam cycle push the design limitations of materials used in tubing, piping, turbine blades, turbine rotor and turbine shell. There continue to be questions regarding the maturity of the metallurgy and pre-and-post weld fabricating and treatment processes and the adequacy of current repair techniques for these facilities. Each advance in

pressure or temperature is limited in some way by material and/or manufacturing limitations, and occasionally by other factors which serve to plateau the efficiencies until those limitations are overcome. When those limitations are overcome, "ultra-supercritical" is redefined at a new higher standard to achieve in manufacturing capability. There is no bright line that distinguishes between a supercritical and an ultra-supercritical boiler design as there is between subcritical and supercritical.

Until recently, few new domestic high efficiency supercritical facilities have been constructed. Many of the new facilities characterized as ultra-supercritical are located in East Asia, with little design and operating information about these sources being available. Having this information accessible and verifiable is critical to making a determination that an ultra-supercritical unit is BACT for the proposed Sunflower expansion.

While KDHE recognizes the benefits associated with improvements in thermal cycle efficiency, decisions concerning operating temperatures and pressures for the steam cycle must be balanced by other considerations relating to reliability and maintainability of the facility to be constructed.

Comment 2:

This permit does not address GHG BACT since the issuance date is prior to January 2, 2011.

KDHE Response:

If the ruling is still applicable on January 2, 2011 and the permit has not been issued, the permit shall be reopened to include an analysis of greenhouse gases.

Comment 3:

The draft permit needs to clearly state that requirements in the Air Emission Limitations section of the permit must be complied with. For example, on page 10, paragraphs 3 through 7 of this section of the draft permit seem to be re-stating regulatory requirements. We suggest that the permit state at the beginning of the Air Emission Limitations section that all requirements and conditions included in or referenced in this section must be met.

KDHE Response:

The permit has been reworded to clearly state that Sunflower must comply with these requirements.

Comment 4:

On page 7, the draft permit defines "day" for the 30-day rolling limits to have the same meaning as "boiler operating day" as defined in 40 CFR 60.41Da. We suggest that the permit specify the date of incorporation, for example by stating "as defined in 40 CFR

60.41Da as of July 1, 2010," or simply include the definition in the permit. This will prevent problems if EPA changes the definition of "boiler operating day" in the future.

KDHE Response:

The permit now includes the definition of "boiler operating day".

Comment 5:

On page 7, the draft permit proposes a NO_x emissions limit of 0.05 pounds per million BTU (lb/mmBtu) heat input on a 30-day rolling average basis, excluding periods of startup and shutdown. We understand that this limit is consistent with other NO_x limits in previously issued PSD permits for similar units in the nation. However, the Best Available Control Technology (BACT) is based on the maximum degree of reduction taking into account energy, environmental, and economic impacts and other costs. Therefore, the record should evaluate if lower NO_x rates are technically and economically feasible. The permit record should explain whether these rates are achievable at the proposed unit and if such rates are not achievable, why they cannot be achieved, and why they do not otherwise represent BACT.

KDHE Response:

The cited Texas regulation in the comment establishes a system-based cap and trade program, wherein company-wide emission caps are determined based upon boiler heat input and types (tangential-fired or wall-fired). This type of system-wide standard provides much greater flexibility for units subject to the regulation than for an individual unit meeting a comparable emissions limit. The Texas regulation does not require individual wall-fired or tangentially-fired boilers to meet the NOx emissions limit of .045 lb/MMBtu heat input. See 30 Tex. Admin. Code § 117.1200 et seq. (2007). The rate is used to calculate system wide mass-based daily and 30 day rolling caps.

The 30 Tex. Admin. Code § 101.383 authorizes exceedances of those caps if "surplus emission allowables" are available. "Surplus emission allowables" are defined as the "amount, greater than zero, that a source owner or operator's allowable emissions in a system cap emission limit specified in Chapter 117 of this title (relating to Control of Air Pollution from Nitrogen Compounds) is greater than the actual emissions in that system." 30 Tex. Admin. Code § 101.380. Such surplus emission allowables could be generated as the result of an emission unit not operating.

Tangentially-fired units routinely perform slightly better with respect to NO_x emissions as compared to wall-fired units. EPA has recognized this difference of performance of the different types of boilers in other regulations with coal-fired EGU NOx emissions limits. The BART default emissions limit for a tangential boiler is lower than that for a wall-fired boiler. 40 CFR Part 51 establishes a NO_x emissions limit for tangential-fired boilers of 0.015 lbs/MMBtu and a NO_x emissions limit for wall-fired boilers of 0.023 lbs/MMBtu. A similar

recognition of the difference between the two types of units is reflected in the acid rain limits for the two types of boiler designs.

Emissions rate data from existing similar facilities are useful in determining whether a proposed emissions limitation will be achievable at the new source. However, BACT does not require the selection of an emissions rate that has not been rigorously demonstrated to be achievable over the life of the facility. Permit writers retain discretion to set BACT levels that do not necessarily reflect the highest possible control efficiencies but will allow permittees to achieve compliance on a consistent basis. Prior KDHE decisions recognize a distinction between 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.

In the case of a new generating unit, an allowance must also be made for uncertainty in the actual performance of equipment. Similar allowance must be given in the consideration of manufacturer claims of performance or information in the technical literature concerning experience at other operating units or from vendor tests. This consideration becomes especially important when comparison is made to the very best operating performance achieved by one generating unit out of many in a diverse population subject to a system-wide regulatory structure.

In conclusion, the following points support the KDHE decision to establish a NO_x emissions limit of 0.05 pounds per million BTU (lb/mmBtu) heat input.

- *The Texas units referenced in the comment are not BACT emissions limitations.*
- *The Texas regulation provides flexibility for each individual unit not granted to the proposed H2 unit due to the system-wide nature of the regulation.*
- *The Texas regulation affects both tangential and wall fired units with a comprehensive emission limit.*

- *Tangentially-fired units routinely perform better with respect to NO_x emissions as compared to wall-fired units.*
- *The limit in the permit is consistent with other NO_x limits in previously issued PSD permits for similar units in the nation.*

Comment 6:

On page 4, in the listing of the Significant Applicable Air Pollution Control Regulations, the draft permit lists Kansas' administrative regulation related to excess emission events (startups, shutdowns, and malfunctions). The draft permit includes such events in certain emission limits and is silent as to such events in other emission limits. Under the Clean Air Act, the BACT requirement and the relevant NAAQS and increments must be protected at all times, including instances of startup, shutdown, and malfunction. Therefore, to ensure compliance with the Clean Air Act and implementing regulations, we recommend the permit delete the reference to operation under the general regulation relating to excess emissions. The permit may, however, contain secondary limitations for periods of startup, shutdown,

and malfunction provided such limitations ensure compliance with the BACT provisions and do not authorize the source to cause or contribute to a violation of the NAAQS or increments.

KDHE Response:

An introductory paragraph under Air Emission Limitations has been included in the permit on page six. This paragraph makes clear that except where explicitly indicated otherwise, the limitations apply at all times including periods of startup, shutdown, and malfunction. In circumstances when the general limitations do not apply, secondary limitations are included, if required by applicable law.

There is no requirement to include malfunctions in allowable emission limits. K.A.R. 28-19-350(d) adopts by reference 40 CFR Part 51 Appendix W, the Guideline on Air Quality Models. Appendix W §8.1.2 recommends modeling point sources using, at a minimum, the design capacity. Malfunctions which may result in excess emissions are not considered to be a normal operating condition, and should not be considered in determining allowable emissions.

Comment 7:

Examples of where the draft permit is confusing on startup, shutdown, and malfunction events include:

On page seven, the proposed NO_x limit states that emissions during startup and shutdown shall be limited to an average of 1,740 lb/hr determined on an "individual event basis." The draft permit does not provide an averaging time for the limit and does not define an "individual event basis." The draft permit does not state whether periods of malfunction shall be included in this limit.

On page eight, the proposed SO_2 limit states that during periods of startup and shutdown, the total annual emissions of SO_2 will not exceed 3,239 tons. The annual limit does not correlate with the abbreviated nature of startup and shutdown events and the potential impact of emissions during these events on the short-term SO_2 limits. In general, it is difficult to enforce annual limits. We suggest looking at options for a time frame that could be more easily enforced but still allows Sunflower operational flexibility, such as a 12-month rolling total.

We read the draft permit to include malfunctions in the 30-day SO_2 limit but it is not clear if that was the permit's intent. The draft permit should state whether periods of malfunction are included in the PM emission limit on page eight. The draft permit should state whether periods of startup, shutdown, or malfunction are included in the VOC limit on page nine.

KDHE Response:

The NO_x emissions limitation as expressed in paragraph two under "a" on page eight now reflects the average emissions over the duration of each startup or shutdown event.

The SO_2 emissions limitation as expressed in paragraph two under "b" on page eight now reflects a rolling 12-month basis for the limitation.

For clarification of individual events, the NO_2 and SO_2 startup and shutdown are now formally defined by the temperature at the inlet of the SCR (NO_x) and FGD (SO_2).

For malfunctions, see response to Comment 6.

The 12-month rolling average emissions limitation is applicable to events of malfunction.

The VOC emissions limitations include startup, shutdown and malfunction. They are verified by correlating their emissions with CO, if correlation can be reasonably shown to exist.

Comment 8:

The draft permit on page 18 in Paragraph eight of the section titled "Reporting," provides additional information regarding malfunction events. This paragraph should make clear that excess emissions during startup and shutdown are violations unless in compliance with conditions expressly providing for secondary emissions limits as described above. The permit should also state that excess emissions during malfunction events may constitute violations and are subject to enforcement.

KDHE Response:

Paragraph eight relates to reporting requirements in the event of a malfunction that results in an exceedance of an emissions limitation. The draft permit provides that emissions limitations apply at all times unless expressly provided otherwise in the permit and that compliance with Paragraph eight does not absolve the permittee of potential liability for an exceedance of an emissions limitation. It merely confirms KDHE's discretion to forego enforcement action in the event of a temporary exceedance of an emissions limit action under appropriate circumstances.
The permit has been modified to establish action levels which require Sunflower to present such information that allows KDHE to evaluate whether, taken together, the emissions from the various sources might result in impacts that would exceed the NAAQS. If circumstances warrant, KDHE may require that Sunflower conduct modeling to provide such necessary assurance Accordingly, the agency reserves the means to be certain that this provision cannot be used to circumvent the applicable law as it relates to emissions limitations.

Comment 9:

The permit needs to define HAPs to make it clear which pollutants are included in the HAP limit.

KDHE Response:

KDHE has modified the permit by adding a reference to K.A.R. 28-19-200 and 28-19-201.

Comment 10:

The permit limits for HAPs should be expressed as tons per 12-month period instead of tons per year to clarify that a year is any consecutive 12-month period and not a calendar year.

KDHE Response:

The permit has been changed to any consecutive 12-month period.

Comment 11:

The draft permit requires the chlorine and fluorine concentration in the coal burned to be sampled once each calendar quarter. This frequency would allow the operator to select the lowest chlorine and fluorine containing coal to sample. Considering the possible variability in coal chlorine and fluorine content, the permit should require sampling of every shipment of coal received. A quarterly average chlorine and fluorine concentration can be calculated based on the content in the coal and the mass of coal received. This concentration should be used to adjust the emission rates in paragraph two on page 17 of the Recordkeeping section of the draft permit to determine compliance with the hydrogen chloride and hydrogen fluoride HAP limits by multiplying by the average coal content and dividing by the content of the coal during the test.

KDHE Response:

KDHE is modifying the permit to require representative coal sampling and analyses to ensure compliance with the HAP requirements. A composite sampling of the coal is supplied from each mine shipped from each train. The analysis shall be performed each calendar month from a weighted average of all composite samples from all mines shipped that month.

Comment 12:

In Recordkeeping on page 18, paragraph 4, the draft permit requires the 12-month rolling average to be maintained. In Reporting on page 18, paragraph 7 the draft permit requires 12-month rolling average emissions to be submitted. We believe you intended these to be 12-month rolling totals of the emissions.

KDHE Response:

The permit has been modified to reflect 12-month rolling totals.

Comment 13:

More information should be provided regarding the relationship of the sulfur dioxide control efficiency and hydrogen chloride and hydrogen fluoride control efficiency. We are concerned that if Sunflower operated the sulfur dioxide control equipment at a higher than required efficiency during the HAP stack tests that would bias the test results, which in turn would bias the HAP emission calculations.

KDHE Response:

Sunflower has submitted the materials in support of the HCl and HF emissions estimates. During the period in which the joint DOE/EPRI/ADA-ES/Sunflower test program[1] was conducted, and during recent follow-up tests,[2] the stack SO_2 emission rate identified in the test reports were higher — and therefore at a lower efficiency — than that required by the SO_2 emissions limitation in this permit. Therefore, the information submitted in the reports is more conservative

Comment 14:

The general description on page 3 states that "there is no potential" that Unit 2 could exceed the major source HAP limits. The permit record should include an explanation as to why the major source limit for HAPs is not exceeded and explain how the monitoring and testing requirements included in the permit demonstrate this.

KDHE Response:

KDHE references Appendix L in the Updated Application Materials in which Sunflower identified the HAP emissions measurements on Holcomb 1, comparing those estimates both to AP-42 factors and to the Emission Handbook produced by EPRI. Sunflower further discussed in Part 1 of the Application the comparability expected on the H2 unit when scaled-up for the size differences. Sunflower also presented in Appendix L the relative efficiencies of the applied control technologies as evidence that compliance with the emissions limitations of SO_2, CO, PM, PM_{10}, and $PM_{2.5}$, as further measured by performance tests, is adequate demonstration that the unit will not be a major source of HAPs. Additionally, comparisons of estimated H2 emissions (and actual H1 emissions) to those measured on recently constructed units[3] equipped with the same control technology confirms the validity of Sunflower's calculations.

The permit requires verification of the accuracy of these analyses by post-construction stack testing. The permit contains effective limits on the H2 potential-to-emit; and compliance

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[1] SDA Scrubber Speciated Mercury, HCl/HF/Br^+, and Trace Metals Emissions Baseline Study – August 6, 2004 and SDA Scrubber Speciated Mercury, HCl/HF/Br^+, and Trace Metals Emissions Long-term Study – October 5, 2004.

[2] Particulate, Sulfuric Acid Mist, and Halide Emissions Study Test Report – September 25, 2009.

[3] Table of units for which test results are available; submitted by Sunflower Electric, referenced in KDHE file C-8849, Nov. 29, 2010.

with these emissions limitations is assured by the permit monitoring, recordkeeping and reporting requirements.

Comment 15:

On pages 7 and 8, the draft permit limits NO_x and SO_2 emissions for the Unit 2 on a 30-day average. The existing unit is also subject to 30-day limits. There can be considerable variability in 1-hour emission rates. Therefore, to assure compliance with the 1-hour NO_x and SO_2 NAAQS, the permit needs to contain NO_x and SO_2 1-hour average emission rates for both the new and existing steam generating units. The existing unit needs the 1-hour limits because its emissions are important to the modeling demonstration for the proposed unit. To ensure the source does not cause or contribute to a violation of the NAAQS, the emission limits must be consistent with the modeling rates and have the same averaging period, i.e. in this case 1-hour average emission rates for the 1-hour NAAQS.

KDHE Response:

Please refer to Section III.A. The CAA does not require KDHE to implement the new regulatory requirements (1 hour NO_2 and SO_2 NAAQS) contained in this comment.

There are now action level limits in the Permit Conditions, Monitoring and Reporting portions of the permit.

A permit condition has been added to address 1-hour SO_2 emissions. If the total SO_2 emissions from H2 exceed 4089 lb/hour during any 1-hour period, the facility is required to notify KDHE, and could be required to conduct an air dispersion modeling analysis.

If the NO_x 1740 lb/hour limit for H2 is exceeded during any 1-hour period, the facility is required to notify KDHE, and may be required to conduct an air dispersion modeling analysis.

Actual operating data for H1 from 2000 through 2009 demonstrates that the SO_2 emission rate of 4089 lb/hour used in the air dispersion modeling analysis is representative of actual emissions.

Actual operating data for H1 from 2005 through 2009 demonstrate that the NO_x emission rate of 1740 lb/hour used in the air dispersion modeling analysis is representative of actual emissions.

There is no regulatory provision that requires the imposition of permit limitations on existing sources at Holcomb Station due to the 1-hour SO_2 and NO_2 new NAAQS.

Comment 16:

The permit needs to specify that construction cannot commence until a construction permit is issued limiting Sunflower's Garden City facility's fuel oil sulfur content to less than 0.5% since that restriction is assumed in the modeling.

KDHE Response:

The construction approval, C-9092, was issued to Sunflower Electric-Garden City Station on 8-31-10 to limit amount of sulfur in the #2 fuel oil. The limit is the use of ultra low sulfur diesel with a maximum sulfur content of 15 ppm in units GC1, GC2, GC3, S2, S3, S4 and S5.

Comment 17:

The air quality analysis must include impacts in all areas that are "ambient air." Therefore, the permit record needs to demonstrate that public access, to Sunflower's property that was not modeled, is precluded by a fence or other physical barrier.

KDHE Response:

Sunflower has provided KDHE information confirming that public access to the Sunflower property in the modeled area is restricted by way of barbed-wire security fencing along, or outside, the perimeter indicated in the modeling protocols.

Comment 18:

For the reasons stated in EPA's June 28, 2010 memo "General Guidance for Implementing the 1-hour NO_2 National Ambient Air Quality Standard in Prevention of Significant Deterioration Permits, Including an Interim 1-hour NO_2 Significant Impact Level" the emergency equipment's emissions should be modeled as occurring at any time instead of just occurring between the hours of 8:00 am to 5:00 pm.

KDHE Response:

Please refer to Section III.A. The CAA does not require KDHE to implement the new regulatory requirements contained in this comment (new 1-hour NO_2 NAAQS).

The 1 hour NAAQS standard for NO_2 became effective on April 12, 2010. The guidance referenced was not published when decisions were made concerning air dispersion modeling for this project.

The replacement H1 Diesel Fire Pump (DFP) and DFP Booster Pump are modeled at full load 8760 hours per year. The H2 Emergency Generator is modeled for testing and maintenance operation between 9:00 am and 6:00 pm.

Additionally the purpose for which the generator may be operated is further described in the permit:

> *The emergency diesel generator shall not be operated for more than 100 hours per year for testing and maintenance. Maintenance and testing hours of operation, except for necessary operational demonstrations to prove completion of maintenance, shall occur between 9:00 AM and 6:00 PM. Otherwise, the emergency diesel generator shall be used only to provide electricity to a specific essential Holcomb 2 plant distribution bus during periods requiring an alternative supply of electricity due to unavoidable loss of normal plant supply. Hours of use shall be verified by the use of non-resettable run time meters…*

The existing H1 emergency generator has 613 hours of service between 1983 and the end of August 2010, a period of 27 years – or 22 hours per year. Testing is weekly, and once per month load is applied to the generator, for an average period of weekly operation less than 30 minutes. The operation of H2 emergency generator is expected to be similar to the operation of the existing H1 emergency generator, including the hours of operation.

H2 emergency generator is expected to be used for emergency operation. It is very unlikely that pieces of equipment including H1 and H2 aux boilers, H1 emergency generator, H1 Diesel Fire Pump, and DFP booster pump would operate simultaneously with the H2 emergency generator,. H1 emergency generator is not expected to be tested at the same time as the H2 emergency generator. Therefore, the modeling scenario used, which included 24 hours per day, 8760 hours per year simultaneous operation for H1 and H2 boilers, H1 and H2 aux boilers, H1 Diesel Fire Pump and DFP booster pump, with 9:00 am to 6:00 pm simultaneous operation of the H1 and H2 emergency generators, is conservative.

Comment 19:

On page 3, in the fourth paragraph, the draft permit states that "mercury is not regulated under 40 CFR Part 52." It should be made clear in permit record that mercury is a hazardous air pollutant that is regulated under Section 112 of the Clean Air Act (42 U.S.C. §. 7412) and not under the PSD program. The record should explain that the mercury limits in the permit are from the May 4, 2009, agreement between Kansas and Sunflower.

KDHE Response:

Language has been updated to clarify the status of mercury as a HAP. The permit states that mercury is limited by state-only conditions.

Comment 20:

The Permit Conditions in paragraphs 7 and 8 on page 12, state that emergency operation is unrestricted. Rather than allowing unrestricted operations, the permit should include a definition of emergency and a requirement to do what is reasonable to minimize emissions during emergency events.

KDHE Response:

Language stating that the permit allows unrestricted operation has been removed and the details specifically addressing when operation, other than maintenance, will be required has been added to the permit.

Comment 21:

The Title V Requirements section on page 20 is unclear about what is required for Title V. The draft permit does not specify that the current Title V permit is for Holcomb Unit 1 and that the Title V permit shall be modified to include the requirements of the construction permit.

KDHE Response:

The Title V Requirements section of the permit has been clarified to address this comment.

Comment 22:

The draft permit should define the terms "commercial operation" and "maximum production rate" even though various testing and monitoring requirements are based on these terms.

KDHE Response:

The term "commences commercial operation" was removed from the Description of Activity referenced in the auxiliary boiler operation during the construction period and changed in Compliance and other Performance Testing #9.

The term "maximum production rate" has the same meaning as used in 40 CFR 60.8, the general performance test provisions of the NSPS.

Comment 23:

The application appears to lack a detailed schedule for construction as required by 40 CFR § 52.21(n)(1)(ii), which is incorporated by reference in the Kansas state implementation plan, K.A.R. 28-19-350. We believe this required schedule should be provided.

KDHE Response:

A detailed schedule for construction has been submitted, which is on record as part of the permit application.

Comment 24:

The permit needs to assure ongoing compliance with the various emission limits. For volatile organic compounds, lead, and sulfuric acid the draft permit only requires a one-time performance test. See page 12, paragraph 4. The draft permit should list methods to

determine ongoing compliance with these emission limitations. Also, the draft permit in paragraph 12 on page 15 requires the first HAP test within 90 days after achieving 90% of the maximum production rate. We suggest that this be clarified as the maximum hourly production rate.

KDHE Response:

The permit has been modified to determine a correlation between emissions of CO, SO2 and PM to verify continuous compliance with VOC, sulfuric acid and lead. By stating 90% of maximum production rate during a test of limited duration, we expect 90% of hourly maximum production rate.

Comment 25:

EPA has finalized the rule "Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$) – Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC)." This rule was published in the October 20, 2010 Federal Register (75 FR 64864, October 20, 2010) and the SILs, the portion of the rule most relevant to this permitting action, will be effective on December 20, 2010. SILs are a screening tool used to determine whether a proposed source's emissions will have a "significant" impact on air quality in the area. If an individual facility projects an increase in air quality impacts less than the corresponding SIL, its impact is presumed to be de minimis and the permit applicant would not be required to perform a more comprehensive, cumulative modeling analysis. Using a SIL developed by KDHE during the permitting process, Sunflower concluded that there was no need for a comprehensive source impact analysis involving a cumulative evaluation of the emissions from the proposed source and other sources affecting the area for $PM_{2.5}$. In light of EPA's recent decision on $PM_{2.5}$ SILs, we recommend that either a cumulative National Ambient Air Quality Standard (NAAQS) impact analysis be provided, or that KDHE provide a detailed justification for its conclusion that a more comprehensive analysis is not needed to show the predicted impact of the project on the NAAQS.

KDHE Response:

Please refer to Section III.A. The CAA does not require KDHE to implement the new regulatory requirements contained in this comment ($PM_{2.5}$ SIL).

When a facility submits a permit application, it is reasonable for KDHE, as the permitting authority, to be able to define rules and regulations that apply to the proposed project with certainty.

Since the January 13, 2010 update to the Sunflower permit application, EPA has promulgated and/or published numerous new regulatory requirements and/or recommendations for a facility seeking a permit.

With the new final rules, EPA did not (and still does not for many of these) have in place final significant impact levels, significant monitoring concentrations, increment, post processors and other implementation guidance and tools that are needed for a dispersion modeling analysis. In addition to the new standards, a NAAQS for $PM_{2.5}$ has existed since 1997, also without final significant impact levels, significant monitoring concentrations, increment, and other implementation guidance and tools from EPA needed for a dispersion modeling analysis. A final rule for $PM_{2.5}$ significant impact levels, significant monitoring concentrations, and increment was published on October 20, 2010, five days before the final public hearing scheduled for Sunflower's proposed permit.

SILs and PSD Increments will need to be incorporated into the Kansas State Implementation Plan (SIP) prior to being considered enacted on a state level. When EPA failed to promulgate SILs and SMCs with the NAAQS, it was left up to each individual state to determine what threshold levels to establish in the interim. These levels were set by each state in order to allow for a minimum threshold that should be established below which a project does not have a significant impact on the air quality standards.

KDHE developed SILs and determined that they constitute de minimis impacts and are protective of the NAAQS. KDHE set those interim levels (5 $\mu g/m^3$ for 24-hour and 1 $\mu g/m^3$ for annual) in a memorandum dated September 22, 2010 and has indicated that they will remain in place until such time as any newly promulgated federal standards can be incorporated into the Kansas SIP. The PSD increments will go into effect one year from the date of publication in the Federal Register. The SILs and SMCs will become effective where applicable 60 days after publication. Notice of these regulations was published in the Federal Register on October 20, 2010. Therefore, the federal SILs will take effect where applicable on December 20, 2010.

Although the KDHE interim SILs are still in effect, comments have been received that recommend modeling be rerun and impacts evaluated with respect to the newly promulgated SILs. However, a new modeling analysis is not necessary, as modeling that was performed for PM_{10} can be used to demonstrate that $PM_{2.5}$ impacts are within allowable criteria. Sunflower performed $PM_{2.5}$ significance modeling (screening modeling) for just the Holcomb 2 sources and determined that the impacts were below KDHE-approved SILs: 3.76 $\mu g/m^3$ compared to the 5 $\mu g/m^3$ (24-hour) SIL and 0.39 $\mu g/m^3$ compared to 1 $\mu g/m^3$ (annual) SIL. Based on those modeled results, cumulative $PM_{2.5}$ modeling (refined modeling) was not required.

An analysis of the Sunflower modeling performed for PM_{10} can be used in lieu of performing a separate $PM_{2.5}$ cumulative (refined) modeling analysis. The cumulative PM_{10} NAAQS model results make this demonstration, as follows: $PM_{2.5}$ is a subset of PM_{10} and the model makes no distinction between the two particle sizes in the manner in which it manages the calculations. If the cumulative PM_{10} modeling demonstrates compliance with the PM_{10} NAAQS, and assuming all PM_{10} is $PM_{2.5}$, the result is that any cumulative analysis performed for $PM_{2.5}$ would likewise indicate that it does not exceed the $PM_{2.5}$ NAAQS. That is, if the cumulative modeled impact ($\mu g/m^3$ result) for the larger particle size PM_{10}, when combined with the $PM_{2.5}$ background level does not exceed the $PM_{2.5}$ NAAQS, then any

cumulative modeling analysis of the smaller fine-particle size $PM_{2.5}$ combined with the same background level, likewise would not exceed the $PM_{2.5}$ NAAQS. Such analyses have been upheld by the Environmental Appeals Board (EAB) (e.g., in connection with the BP Cherry Point PSD construction permit).

Based on the results of the PM_{10} cumulative modeling, the following calculations make that demonstration. The PM_{10} significance modeling (just the Holcomb 2 sources) predicted impacts of 12.28 µg/m^3 (24-hour) and 0.98 µg/m^3 (annual[4]). These results are greater than the $PM_{2.5}$ significance modeling predicted impacts of 3.76 µg/m^3 (24-hour) and 0.39 µg/m^3 (annual), thus demonstrating that using the PM_{10} modeling to show compliance for $PM_{2.5}$ modeling is conservative for Holcomb 2.

The PM_{10} cumulative modeling results (µg/m^3), in combination with the $PM_{2.5}$ background also are less than the $PM_{2.5}$ NAAQS.

Table 2. Holcomb 2 Particulate Modeling Demonstration

	PM_{10} Cumulative Modeled Impact (ug/m^3)	*$PM_{2.5}$ Background (ug/m^3)*	*Total (ug/m^3)*	*$PM_{2.5}$ NAAQS (ug/m^3)*
24-hour	*13.27*	*18*	*31.3*	*35*
Annual	*1.66*	*8*	*9.7*	*15*

The analysis presented above demonstrates that potential $PM_{2.5}$ emissions from Holcomb 2 will not cause or contribute to a modeled exceedance of the $PM_{2.5}$ NAAQS even if the modeling exercises were to utilize the newly promulgated federal SILs.

Comment 26:

The air quality analysis for sulfur dioxide, particulate matter, and nitrogen dioxide, performed to determine compliance with the NAAQS and increments for those pollutants, assumes that the source will be built and operated as modeled. Parameters such as stack height, stack diameter, exit velocity, temperature, and emission rate that describe how the source was modeled and how the source would be designed and built are contained, in Part 5.0 and 5.0a of the application which was last revised in August 2010. Paragraph 7 of the "Permit Conditions" section in the draft permit requires Sunflower to document NAAQS compliance to KDHE prior to making significant changes to modeled source parameters of the emergency generator. We recommend this condition: a)

[4] EPA has revoked the annual NAAQS for PM_{10}. However, the AERMOD software determines the modeled value as a matter of course.

be expanded to cover all emission units that will be constructed for this project; and b) require analysis for both the increment and the NAAQS. Finally, the permit should be worded to clarify that it is the Kansas Department of Health and Environment's authority to decide what is a "significant change."

KDHE Response:

A permit condition has been added to address this comment.

Comment 27:

Sunflower used the Plume Volume Molar Ratio Method (PVMRM) model option for the 1-hour nitrogen dioxide (NO_2) modeling. The PVMRM model option estimates the conversion of nitrogen oxides (NO_X) to NO_2 considering the available ozone. The record needs to have an adequate justification for using the PVMRM option for the Sunflower permit modeling. In addition, please ensure that KDHE provides a rationale for the choice of a non-default value for the NO2EQUIL parameter and for the NO_2/NO_x in stack ratios. The NO_2/NO_X ratio should consider the effect of pollution control equipment on the ratio. For more information for justifying the use of the PVMRM model option, see page 3 of the June 28, 2010 memo from Tyler Fox to the Regional Air Division Directors titled "Applicability of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard."

KDHE Response:

Please refer to Section III.A. The CAA does not require KDHE to implement the new regulatory requirements contained in this comment (1 hour NO_2 NAAQS).

PVMRM was used in the air dispersion modeling analysis for predicting 1-hour average NO_2 impacts to compare to the recently promulgated 1 hour NO_2 standard. PVMRM is a refined method for predicting NO_2 ambient impacts caused by a source and is included in the regulatory version of AERMOD as a non-default option. PVMRM is adequate both in terms of accuracy and conservatism for predicting NO_2 impacts on 1-hour and annual bases. The following is an overview of the development of PVMRM, as delineated in Section 1.5.1.1.1 of Sunflower's August 2010 NO_2 modeling report.

As far back as 1996, the Guideline for Air Quality Models, 40 CFR 51 Appendix W (Appendix W) outlined a 3-tier technique for evaluating NO_2 impacts. The first tier was to assume 100 percent conversion of nitric oxide (NO) to NO_2. The second tier relied upon monitored data and derived an atmospheric equilibrium value of 75 percent conversion, called the Ambient Ratio Method (ARM). It was found (via monitored data) that both Tier 1 and Tier 2 method assumptions of ambient equilibrium were very conservative, causing large over-estimations of NO_2 concentrations (as compared to monitored data) at receptors near the modeled source (within approximately 10 km). Tier 3 is the use of a more detailed screening method selected on a case-by-case basis, such as the Ozone Limiting Method

(OLM) that was developed to more closely approximate NO_2 ambient concentrations by molar balance of ozone (O_3) with NO (the two gases that react chemically to form NO_2).[5]

The drawback to the OLM method was that it could only be used for a single-source application. For this reason, the PVMRM model was developed in 1999 to better simulate the NO-to-NO_2 conversion chemistry during plume expansion. PVMRM is particularly well suited for the near receptor area where maximum modeled NO_X concentrations are usually predicted, because the PVMRM method follows the chemistry of the main forward reaction of NO with O_3 as it occurs during expansion of a plume segment traveling downwind. The PVMRM method also can be used for both single and multi-plume analyses (Hanrahan, 1999).

KDHE provided EPA Region 7 all information submitted by Sunflower regarding its use of PVMRM for review. In the guidance memorandum released by EPA on June 28, 2010, PVMRM was discussed in detail, and it was indicated that:

> *[PVMRM's] use as alternative modeling techniques under Appendix W should be justified in accordance with Section 3.2.2, paragraph (e), as follows:*
>
> *e. Finally, for condition (3) in paragraph (b) of this subsection [preferred model is less appropriate for the specific application, or there is no preferred model], an alternative refined model may be used provided that:*
>
> *i. The model has received a scientific peer review;*
>
> *ii. The model can be demonstrated to be applicable to the problem on a theoretical basis;*
>
> *iii. The data bases which are necessary to perform the analysis are available and adequate;*
>
> *iv. Appropriate performance evaluations of the model have shown that the model is not biased toward underestimates; and*
>
> *v. A protocol on methods and procedures to be followed has been established."*

The EPA memo indicates that items (i) and (iv) are fulfilled in part, "…based on existing documentation (Cole and Summerhays, 1979; Hanrahan, 1999a; Hanrahan, 1999b[6]*; MACTEC, 2005)," while the rest of the items should be routinely addressed as part of the modeling protocol. As discussed in the Sunflower final NO_2 modeling report at Section 1.5.1.1.2, two other items complete the requirements of items (i) and (iv) above: (1) PVMRM has been independently tested and, on January 17, 2006, was approved by EPA Region 10*

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[5] Hanrahan, P.L., "The plume volume molar ratio method for determining NO_2/NO_x ratios in modeling. Part I: Methodology," *J. Air & Waste Manage. Assoc.* **1999**, *49*, 1324-1331

[6] Hanrahan, P.L., "The plume volume molar ratio method for determining NO2/NOX ratios in modeling. Part II: Evaluation Studies," *J. Air & Waste Manage. Assoc.* 1999, *49*, 1332-1338.

for use in Alaska;[7] *(2) EPA used PVMRM to estimate the conversion of NO_X to NO_2 in its risk and exposure assessment to support the new 1-hour NO_2 NAAQS.*[8] *This risk and exposure assessment was a key consideration in EPA's decision-making process.*

With respect to item (ii), EPA states:

> *The issue of applicability to the problem on a theoretical basis (item ii) is a case-by-case determination based on an assessment of the adequacy of the ozone titration mechanism utilized by these options to account for NO_X chemistry within the AERMOD model based on "the chemical environment into which the source's plume is to be emitted" (Appendix W, Section 5.1.j).*

This is discussed at length in Section 1.5.1.1.3 of the Sunflower final NO_2 modeling report, as replicated below:

> *Initial testing of the PVMRM modeling done in 1999 using ISCST3 demonstrated that the PVMRM algorithm performed well, both in predicting ambient NO/NO_2 in-plume ratios, as well as the ground-level receptor impacts as compared to monitor data. Of particular use in a regulatory sense, is that PVMRM was found to realistically predict the NO_2 fraction at close-in receptors yet still provide conservative estimates so that the NAAQS can be protected. See footnote 6.*
>
> *As part of the approval process for USEPA Region 10, a sensitivity study was conducted using PVMRM within the AERMOD modeling framework which compared both annual and 1-hour NO_2 impacts, as well as NO conversion rates to those of the Tier 1, Tier 2, and OLM methods as described above. This study determined, as did the 1999 Hanrahan study, that PVMRM is the best option for providing realistic treatment of the conversion of NO_X to NO_2 as a function of distance downwind from the source, and that "[n]o anomalous behavior of the PVMRM or OLM options was identified as a result of these sensitivity tests."*[9]
>
> *A further study, also conducted for initial Region 10 approval, evaluated whether a model bias could be found in the PVMRM model. Using both in-plume aircraft data from power plants, as well as three long-term field datasets, it was determined that based upon all available data the PVMRM algorithm (as currently contained within the AERMOD framework), "is judged to provide unbiased estimates of the NO_2/NO_X ratio based on criteria that are comparable to, or more rigorous than, evaluations performed for other dispersion models that are judged to be refined, implying unbiased performance."*[10]

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[7] EPA Region 10 Letter from Office Modeling Contact Mr. Herman Wong to Mr. Alan E. Schuler, Alaska Department of Environmental Conservation, January 17, 2006.

[8] EPA Doc. # EPA-452/R-08-008a, "Risk and Exposure Assessment to Support the Review of the NO2 Primary National Ambient Air Quality Standard" (Nov. 2008).

[9] Sensitivity Analysis of PVMRM and OLM in AERMOD, Alaska DEC Contract No. 18-8018-04, MACTEC, December, 2004.

[10] Evaluation of Bias in AERMOD-PVMRM, Alaska DEC Contract No. 18-9010-12, MACTEC, June, 2005

While the PVMRM algorithm is currently a non-default selection within the AERMOD model, sensitivity and bias testing of this algorithm have shown that PVMRM provides superior performance to the Tier 1 and Tier 2 methods as compared to monitored data, and that these superior results are predicted in an unbiased fashion. It is also important to note that these results hold true for 1-hour predictions as well as annual impact predictions.

Thus, items (i), (ii), and (iv) have been satisfied. For item (iii), an inventory of all NAAQS sources was provided by KDHE for an area extending 100 km from Holcomb Station. This inventory was thoroughly reviewed and each individual source categorized so as to properly assign the specific type of activity to each source. This allowed for accurate categorization in the modeling analysis. Representative hourly monitored ozone data as well as a default hourly background ozone concentration for missing hours were also available. Finally, a background ozone concentration that was adequate to add into the modeled NO_2 concentrations to determine the total NAAQS modeled concentration was also available. All databases that are necessary to run the model were both available and adequate for the modeling demonstration.

For item (v), a modeling protocol was compiled and submitted to KDHE, along with multiple modeling assumptions for the various parameters in the AERMOD model necessary to conduct the PVMRM determination. These parameters were reviewed and approved by KDHE, and the modeling demonstrated compliance.

As to the specific point that PVMRM needs to be approved by the EPA Region in question, all modeling data, databases, assumptions, and results were provided to EPA Region 7 for review and comment. EPA provided official comments on October 22, 2010, and the agency's response specifically addressed PVMRM. In this response, EPA did not object to the use of the PVMRM model in this modeling analysis. Instead, EPA indicated only that there needed to be sufficient justification for the use of the model, the modeled parameters, and that KDHE follow the guidance set forth in the EPA June 28, 2010 memorandum discussed in detail above. All aspects of that memo were adequately addressed, which allows for the use of PVMRM to demonstrate compliance with the new 1-hour NO_2 NAAQS.

EPA has suggested providing justification as to the value of NO2EQUIL. A value of 0.75 was used in the modeling runs, which was determined to be appropriate for this modeling scenario. AERMOD has a default setting of 0.90 (90%), but a review of this information indicated that this does not correspond with current EPA practices and modeling demonstrations outlined in 40 CFR 51 Appendix W. Tier 2 (ARM) of the Appendix W three-tier approach recommends the use of an empirically derived NO_2/NO_X ratio of 0.75 (75%) on an annual basis. Referring to the memorandum issued by Tyler Fox on June 28, 2010, the Tier 2 methodology is explained in greater detail, and the justification for when and where the 0.75 value of NO2EQUIL is discussed.

In general, for low-level releases with limited plume rise, peak hourly NO_x impacts are likely to be associated with night-time stable/light wind conditions. Since ambient ozone concentrations are likely to be relatively low for these conditions, and since low wind speeds

and stable atmospheric conditions will further limit the conversion of NO to NO_2 by limiting the rate of entrainment of ozone into the plume, the 0.75 national default ratio will likely be conservative for these cases.

A review of the database used for the NO_2 NAAQS inventory reveals that the dominant stack heights are approximately 30 feet, making them all low level releases. In the inventory of 387 sources, the average stack height was 32.5 feet and the median stack height was 27.8 feet, demonstrating that these sources are characterized as low level releases. While there are some taller stacks in the overall model, it is not necessary to increase the NO2EQUIL ratio to 0.9 to account for these few sources and hence lead to an over prediction of the impacts from the predominantly low-level releases prevalent in the model. This is further demonstrated by examining the results of the 1-hour NO_2 model and understanding that the high impacts that are recorded are primarily a result of the low-level release stacks, thus further emphasizing the appropriateness of using 0.75 as the NO2EQUIL value.

Of greater significance is that 0.75 is also the value EPA used in its risk and exposure assessment to support the new 1-hour NO_2 NAAQS, and is appropriate or conservative for the modeling for this project.[11] *As EPA has determined that this is an appropriate factor to use on a long term basis as well as for the determination of the new 1-hour NO_2 standard, it was determined that it was also appropriate to use for the modeling for this project. As such, the NO2EQUIL keyword was set to 0.75.*

Sunflower provided documentation of NO_2/NO_x in stack ratios and references, which contain justifications for their use, in the Air Dispersion Modeling Analysis for Compliance with the Nitrogen Dioxide 1-Hour NAAQS, submitted August 19, 2010, pages 13-15. KDHE has reviewed these ratios and concurs with their usage.

Comment 28:

KDHE should ensure that it has followed the appropriate procedures at 40 CFR 52.21(p) for notifying Federal land managers.

KDHE Response:

KDHE has followed appropriate procedures for notifying Federal land managers. K.A.R. 28-19-350(b)(1), which adopts by reference 40 CFR 52.21(p)(1), contains a requirement to provide written notice of any permit application for a proposed major stationary source or a major modification, the emissions from which may affect a Class I area, to the Federal land manager and the Federal official charged with direct responsibility for management of any land within such area. The meaning of the term "may affect" is interpreted by EPA policy to include all major sources or major modifications within 100 kilometers of a Class I area. Also, if a major source proposing to locate at a distance greater than 100 kilometers of such size that the reviewing agency or FLM is concerned about potential emission impacts on a

[11] EPA Doc. # EPA-452/R-08-008a, "Risk and Exposure Assessment to Support the Review of the NO_2 Primary National Ambient Air Quality Standard" (Nov. 2008).

Class I area, the reviewing agency can require the applicant to perform an analysis of the source's potential emission impacts on the Class I area.[12]

Please refer to Section III.D.1. The two closest Class I areas from the proposed project are Great Sand Dunes National Park, approximately 399 kilometers from the proposed project, and Wichita Mountain National Wildlife Refuge, approximately 409 kilometers from the proposed project. Because of the distance and the reduced size of the proposed facility, KDHE does not believe notification was a requirement. However, KDHE provided a copy of the public notice and the draft permit to FWS because of their previous comments about the Wichita Mountains. KDHE supplied FWS information and indicated the 2007 analysis was used in lieu of a separate analysis for H2 alone, due to the large reduction in emissions. The FLM did not object due to the decreased emissions of the proposed project.

Comment 29:

KDHE should ensure that the record has an adequate justification for why the Class I visibility modeling for the previous project design (two boilers and three boilers) is conservative in light of current models and the current design of the single unit.

KDHE Response:

Please refer to Section III.D.1.

Sunflower caused the Class I visibility modeling in 2007 to be developed first for three 700-MW (H2, H3, and H4) and later for two 700-MW units (following the withdrawal of H4). The comprehensive modeling results for 2007 did not find any significant visibility impacts at the two closest Class I areas, Wichita Mountain National Wildlife Refuge, (approximately 409 kilometers from the proposed project) or for Great Sand Dunes National Park (approximately 399 kilometers from the proposed project). The stack height modeled is virtually the same, and the stack location has been altered only by relocation approximately 100 feet north of the site modeled in 2007. Finally, the selected control technology, the stack temperature and velocity parameters have not changed, and the emission rates are less than those from two units. The impacts that would be predicted by the reduction in unit size from 1400-MW to 895-MW would only be further diminished at any distant receptor evaluated.

Comment 30:

EPA fully supports the proposed condition stating that the permit will expire if construction is not commenced and completed timely as specified in paragraph 1 of the "General Provisions" section. We expect compliance with this condition to be closely monitored.

KDHE Response:

[12] New Source Review Workshop Manual DRAFT October 1990, p. E.16.

KDHE concurs. K.A.R. 28-19-350(b)(1) adopts by reference 40 CFR 52.21(r)(2), which requires that each permit or approval issued for the construction or modification of a source shall become void if the construction or modification has not commenced within 18 months after permit issuance or if the activity required to complete the modification or construction has been discontinued for 18 months or more.

B. NATIONAL SIERRA CLUB COMMENTS (SC) (Comments 31-53)

Comment 31 (SC Comment II.A):

KDHE must deny the permit because the proposed plant will not be constructed within 18 months. Tri-State has no need for the capacity from the Holcomb expansion.

KDHE Response:

There are no provisions within State or Federal law that prohibits an entity from applying for a PSD permit. Please refer to KDHE Response to Comment 30.

Whether or not the capacity for the electricity is needed from the proposed plant plays no role in the determination of the facility's compliance with the current laws and regulations that govern air quality. Therefore, KDHE has no jurisdiction in the matter of need for capacity from the Holcomb facility.

Comment 32 (SC Comment II.B):

Sunflower Has No Ability to Complete the Project Without Tri-State.

KDHE Response:

Business arrangements and business decisions made by companies in the generation, distribution, and sale of electricity are outside the purview of determining the facility's compliance with the current laws and regulations that govern air quality.

Comment 33 (SC Comment II.C):

KDHE Must Deny the Permit.

KDHE Response:

Please refer to KDHE responses for Comments 31 and 32.

The commenter cites <u>*In re West Suburban Recycling and Energy Center, L.P.*</u> *8 E.A.D. 192 (E.A.B. 1999) as rationale. That case is not applicable in this particular situation. In that case, a permit had been issued and was on appeal, but in the interim, the permittee had sold a substantial portion of the real estate on which the project was to be constructed. Upon learning of the disposition of the real estate, the EAB issued an order to show cause to the*

permit holder to allow it an opportunity to respond and explain whether it still intended to proceed with the project. The permit holder failed to respond to the EAB's show cause order and thus the EAB dismissed the appeal and denied the permit.

In re New York Power Authority, 1 E.A.D. 825, 826 (Adm'r 1983) does not apply in this situation. This case also dealt with circumstances that arose subsequent to the permit being issued as opposed to prior to permit issuance.

Comment 34 (SC Comment III.):

KDHE Must Deny the Permit because the Project will Harm Health and Welfare.

KDHE Response:

Please refer to Section III.A and KDHE Response to Public Comment I.

K.A.R. 28-19-13, which was cited in this comment reads:

> ***28-19-13. Interference with enjoyment of life and property.*** *Compliance with the provisions of these emission control regulations (including exemptions included therein) notwithstanding, should it be found after public hearing that any specific emission source is, tends to be, will be, or will tend to be significantly injurious to human health or welfare, animal or plant life, or property or is or will be unreasonably interfering with the enjoyment of life and property of any inhabitant of the state, or will interfere with the attainment or maintenance of any national ambient air quality standard an appropriate order may be issued to require such additional prevention, abatement or control of the emission involved as is necessary to effect the purposes of the enabling act. (Authorized by K.S.A. 65-3001, 65-3002, 65-3005, 65-3011; effective Jan. 1, 1971; amended, E-73-8, Dec. 27, 1972; amended Jan. 1, 1974.)*

This general regulation implements K.S.A. 65-3011, an enforcement statute. Both the statute and regulation apply to existing emission sources. KDHE makes permitting decisions under the authority of K.S.A. 2009 Supp. 65-3005 and K.S.A. 65-3008. KDHE has adopted K.A.R. 28-19-350 for PSD determinations, which specifically adopts federal regulations designed to prevent significant deterioration of the NAAQS. The NAAQS, by definition, are based on air quality criteria and set at levels necessary to protect public health and welfare. See CAA §§ 108 and 109.

Comment 35 (SC Comment IV.A):

KDHE May Not Issue the Permit without Adequate Public Process. KDHE Must Fully Respond to All Comments.

KDHE Response:

KDHE is bound by both State and Federal law to carry out the permitting responsibilities for

sources of air pollution within the State. KDHE followed the public participation requirements of K.A.R. 28-19-350 and K.A.R. 28-19-204. In addition, the Department put in place:

- *A dedicated website for review of public documents associated with the permit;*
- *An e-mail account to accept public comments via e-mail for the first time for any environmental permit;*
- *WebNow account access for review of documents;*
- *A 45-day and subsequent 30-day public notice period;*
- *Four public hearings that were conducted across the State; and,*
- *A complete and thorough review of all comments received and development of an extensive responsiveness summary.*

Comment 36 (SC Comment IV.B):

KDHE Must Hold an Evidentiary Hearing Before Issuing the Permit.

KDHE Response:

K.S.A. 2009 Supp. 65-3005 enumerates the powers the Kansas legislature has delegated to the Secretary, including the power to hold air quality control hearings. This general grant of authority, however, is further limited for KDHE permitting decisions in K.S.A. 2009 Supp. 65-3008a, as amended by L. 2010, ch. 17, § 142, and K.S.A. 65-3008b. The permit application was filed and the draft permit was developed under the authority of K.S.A. 65-3008 and rules and regulations duly adopted to implement the Kansas air quality act. The public hearing on the draft permit was conducted pursuant to K.S.A. 2009 Supp. 65-3008a, as amended by L. 2010, ch. 17, § 142, which makes no provision for the application of the Kansas administrative procedure act (KAPA) to public hearings conducted under its provisions. K.S.A. 2009 Supp. 77-503, as amended by L. 2010, Ch. 135, §224, limits the application of KAPA to statutes that expressly provide that KAPA provisions govern proceedings under those statutes. KAPA governs state agency adjudicative proceedings. K.S.A. 77-507 and 77-507a. As a result, the public hearing KDHE conducted on the Sunflower Electric draft permit is not an adjudicative proceeding subject to KAPA. As a participant in the public comment process authorized under K.S.A. 2009 Supp. 65-3008a, as amended by L. 2010, ch. 17, § 142, a state agency proceeding within the scope of the Kansas judicial review act, the commenter may raise these issues of law in the Kansas court of appeals. Board of Sumner County Commissioners v. Bremby, 286 K. 745, 749, 189 P. 3d 494 (2008).

Comment 37 (SC Comment V):

Greenhouse Gas Emissions. KDHE must deny the permit because the proposed plant will emit greenhouse gases at rates that present a substantial endangerment to people's health and the environment. Climate change from CO_2 in the atmosphere is having and will have serious negative consequences for Kansas' economy and public health requiring significant reductions in current emissions of CO_2 and no new sources.

KDHE Response:

Please refer to Comment 34. At this time, KDHE does not have any regulations in place limiting CO_2 emissions, nor do federal regulations currently require BACT limits on CO_2 emissions. However, there are a number of recent rulemaking actions, including some that address CO_2 emissions from electric generating units such as H2, taken by EPA which, when and if adopted and effective, could directly or indirectly affect the proposed facility. Future changes in statutory or regulatory requirements applicable to Holcomb 2, whether relating to CO_2 emissions or otherwise, will be required, as necessary.

Comment 38 (SC Comment V.B.):

KDHE must impose cleaner fuel requirements on Sunflower. At a minimum, Sunflower and KDHE must analyze and apply BACT for CO_2 emissions from the Sunflower plant. The State of Kansas guidance regarding climate change and CO_2 dictates mitigation and reduction of CO_2 emissions.

KDHE Response:

See Comments 34 and 37. Since the 2009 amendments to the KAQA prohibit KDHE from promulgating regulations more stringent than required by the CAA, the KDHE "guidance" cited by the commenter may not be applied in this proceeding. Likewise, to the extent that Sunflower has agreed to CO_2 emissions mitigation measures in the May 9, 2009 Sunflower-State settlement agreement, those provisions are outside the lawful scope of this proceeding.

Comment 39 (SC Comment VI.A):

The Permit does not include BACT limits. The BACT Determination Does Not Sufficiently Analyze Cleaner Fuels, Cleaner Production Processes, or Innovative Combustion Techniques.

KDHE Response:

The project that must be addressed when evaluating BACT is the project for which the application has been submitted, in this case, the addition to the Holcomb Station of "an 895 MW (net) base-load power plant that will produce reliable, low-cost energy, utilizing to the maximum extent possible the existing infrastructure at Holcomb Station. Because the most basic object of the Project is to produce an [electric utility generating unit (EGU)] that can be operated as a baseload resource, with high annual utilization over many years, reliability of generation is of prime importance in determining the source to be constructed." Permit Application, Section 1.3.9.

In reviewing alternative technologies prior to the permit application submission, Sunflower considered various technology alternatives for producing reliable, base-load energy, including renewable energy and biomass resources and natural gas-fired, circulating fluidized bed (CFB), integrated gas combined cycle, and nuclear generation technologies. Permit Application, Section 1.3.10. Sunflower concluded that an SCPC steam generator

designed for sub-bituminous, low-sulfur, Powder River Basin (PRB) coal is the only process that meets the inherent design elements of the proposed project based on the following considerations:

- *PRB coal is the most available and economical coal source for power plants located in the service area.*
- *A super-critical steam cycle is the most energy efficient technology available for this type of fuel and unit size range.*
- *Pulverized coal-fired steam generation is the only available demonstrated fossil fuel technology for an EGU of the size required for the generation needs of the participants.*
- *The existing H1 generating unit at the site uses, and H2 will use, PRB coal or other low sulfur western coal, thus utilizing the existing material handling infrastructure to the maximum degree possible to support the new unit.*

An SCPC unit combusts pulverized coal to generate high-temperature, high-pressure steam, which then is used in a high-temperature, high-pressure steam-driven turbine to generate electricity. Sunflower's expansion project includes a super-critical steam generator, high-pressure condensing steam turbine/generator, specific air quality control equipment, including selective catalytic reduction (SCR), dry flue gas desulfurization (Dry FGD), powdered activated carbon (PAC), and a fabric filter/baghouse (FF/Baghouse), a relatively tall stack, and other material handling and by-product disposal systems. H2 will utilize much of the existing facility infrastructure.

IGCC

Sunflower considered IGCC as a potential process and concluded that it did not meet the inherent design elements of the project as explained in Part 1 of the Application, as updated, at 1-12: IGCC generation technology was not selected. An IGCC design utilizes several additional steps and processes to first "gasify" coal in a chemical reaction to create a "syngas" product. The syngas is then used as a fuel to power combustion turbines to generate electricity. Combustion turbines such as those used in an IGCC application are designed for gaseous or liquid fuels and cannot burn pulverized coal.[13] *Similarly, combustion turbines designed for an IGCC plant could not be used in a SCPC plant. Nor could the steam driven turbine, which is an inherent part of Sunflower's design and objective, be used in current IGCC applications.*

Because of the substantially different processes and components of IGCC versus SCPC, the footprint for an IGCC unit would be from two to three and one-half times the size of the footprint of an SCPC unit with similar generating capacity.The design of an integrated SCPC facility provides for maximum utilization of water resources by recycling and reuse, whereas an IGCC facility would necessitate either deep well injection or the development of a waste water discharge permit for some waste water streams. The processes necessary for managing the by-products from a SCPC steam generator are already in place at Holcomb

[13] On the other hand, the combustion turbines used in an IGCC plant are quite similar to those used in a natural gas combined cycle plant (NGCC).

Station. However, with an IGCC facility, there would be additional waste streams, (such as elemental sulfur) which would either need to be sold into commerce or landfilled. IGCC and SCPC are inherently different process technologies; to substitute one for the other would redefine the design of the source.

There are only two operating IGCC electricity generating units in the United States, Wabash and Polk. Both now primarily gasify petroleum coke instead of coal to produce syngas. The two facilities identified by the EAB in the Desert Rock decision[14], Prairie State and Christian County,[15] were permitted in Illinois and are green-field projects that will use Illinois bituminous coal. It may in fact be the case that IGCC is a viable option for use with those fuels. That does not mean it is a viable option for H2, which will use PRB fuel and will be located at an existing facility.

There has been only one relatively small (160 MW) IGCC facility that has used sub-bituminous coal in combination with 20% natural gas, the LGTI facility in Plaquemine, Louisiana, and the gasifier ceased operation in 1995. The one other attempt to use western bituminous coal, the Pinon Pine IGCC facility in Reno Nevada, was never able to sustain operation.

A review of DOE worldwide gasifier data[16] discloses that of the 192 gasifier facilities operating or planned world-wide, only 19 are used in the production of electricity, of which five were designed to utilize coal as a fuel. All five of these are reported in the B&V Coal Technology Selection Study Update.[17] Of these five, only two operate in the US; and none operates on sub-bituminous coal. Only one, Elcogas (in Spain), operates on a Uhde/Prenflo water-wall gasifier, which along with the Shell gasifier, the B&V study concludes as likely being the most suitable for PRB fuel.

Further, the DOE database reveals that there are six additional gasifier-type facilities under construction or active development which will either produce electricity, or electricity in conjunction with syngas (synthetic natural gas). Of the four under construction, only one will use the Shell gasifier (in The Netherlands); and none will utilize sub-bituminous fuel.Of those under development, only one is projected to be of the Uhde/Prenflo type; and none will utilize sub-bituminous fuel.

IGCC units are not demonstrated generation technology for PRB coal. The IGCC units have lower reliability, are more expensive to construct, and have substantially higher operating and maintenance costs than do SCPC units.

In light of Sunflower's stated basic design objective for H2, the desired location within the footprint of the existing facility, and the current(for H1) and the planned(for H2) use of PRB coal to ensure reliable, low-cost energy, KDHE finds IGCC technology would substantially

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[14] *In re Desert Rock Energy Company, LLC*, PSD Permit No. AZP 04-01 (EAB Sept. 24, 2009) (Remand Order).

[15] Notably, Christian County was proposed as an IGCC facility. Therefore, the concept of redefining the source was not implicated in that permitting action.

[16] http://www.netl.doe.gov/technologies/coalpower/gasification/worlddatabase/index.html

[17] Holcomb Expansion Project: Coal Technology Study Update — June 18, 2010.

alter Sunflower's design for H2. To require Sunflower to change its basic design for H2 to satisfy the BACT requirement would require KDHE to depart from longstanding EPA policy. NSR Manual, B-13.

Alternatively, IGCC would be ruled out in Step 2 of the BACT analysis.

While Sunflower did not perform a full cost evaluation of IGCC from the perspective of a control technology, it is significant that White Pine Energy Associates did submit such a document in support of its application for a PSD permit. But for size (530 MW) and location, the White Pine Energy Center is otherwise similar to H2: SCPC-boiler, Dry FGD, fabric filter, and SCR. Emissions limitations for White Pine were slightly higher than for H2. White Pine's proposed emissions limitations for boiler (SO_2 - 0.09 lb/MMBtu, NO_X - 0.07 lb/MMBtu, and PM_{10} - 0.015 lb/MMBtu, were compared to the then-proposed IGCC facilities' lowest emissions limitations. The study found the incremental cost of IGCC as a control technology for SO_2, NO_X, and PM_{10} to be $187,000, $1,614,000, and $1,076,000 per ton, respectively[18].

Given the substantial cost differential between an SCPC and IGCC and the continued lack of demonstration that lower emissions will be achieved, and if they can, at what cost, particularly as compared to the H2, IGCC also would be ruled out in Step 2 of the BACT process for H2.

Natural Gas

The H2 coal-fired project that fits squarely within the projects where EPA has consistently found that an applicant does not have to consider natural gas in the BACT analysis. The fact that some operators, for their unique, specific business reasons, have elected to pursue NGCC projects rather than coal-fired units is not relevant to the H2 permit application review. Similarly, the fact that owners of some existing coal plants have elected to close them down is not relevant to the standards to be applied to H2. The applicant i.e., Sunflower, has the right to make the determination as to what resources best fit its needs. Were there a legal requirement that Sunflower and KDHE consider the use of natural gas as a fuel for the Holcomb 2 EGU, either with respect to a conventional gas-fired boiler or steam generator, a dual-fuel (coal/gas) boiler or steam generator, or an NGCC unit, natural gas would be ruled out in Step 4 of the BACT process, due to the substantially greater fuel cost over the life of the facility.

EPA has consistently held that fuel choice is integral to a power plant's basic design. It has also been long-standing EPA policy that certain fuel choices are integral to the electric power generating station's basic design. See NSR Manual at B.13 No applicant proposing to construct a coal-fired EGU has been required by any court, any EAB decision, or any EPA order to consider building a natural gas-fired combustion turbine generator as part of a BACT analysis.

[18] White Pine Energy Associates, LLC – Appendix 12 Top-Down Commercial Evaluation of IGCC, page 699.

Natural gas is a more expensive fuel than coal.[19]

- *According to data from the Energy Information Administration (EIA), natural gas prices averaged over the period 1999-2008 have been almost four times more expensive than coal. Natural gas prices have averaged $5.75/MMBtu over the ten-year period, whereas the price of coal has averaged $1.46/MMBtu over the same period.*[20]
- *According to EIA projections, natural gas prices are expected to increase by 60 percent between 2010 and 2030. By comparison, coal prices are projected to decrease by 2 percent over the same period. The table below shows EIA projections (from AEO 2010) for natural gas and coal prices for the electric power sector. Based on these projections, coal is expected to cost significantly less than natural gas for the foreseeable future.*[21]

Table 3. Price of Gas versus Coal [22]

	2009	2010	2020	2030
Natural Gas	$4.14	$4.85	$6.42	$7.73
Coal	$2.15	$1.99	$1.98	$2.03

Natural gas prices are volatile.

- *Over the 19-year period from 1989-2008, data from EVA Fuelcast Long Term Outlook 2009 (August 2009), DOE-EIA Electric Power Monthly show average annual natural gas prices have fluctuated widely between a low of $2.16/MMBtu in 1991 and a high of $9.66/MMBtu in 2005, a difference of $7.50/MMBtu. Over the same period, coal prices have varied modestly from a low of $1.20/MMBtu in 2000 to a high of $2.52/MMBtu in 2008, a difference of $1.32/MMBtu.*

- *In 2008, the price of natural gas to the electric power sector averaged $9.35/Mcf, an increase of 28 percent over 2007. Gas prices in 2009 dropped to $4.26/Mcf, demonstrating the volatility of gas prices.*[23]

- *The levelized cost of electricity (LCOE) for new natural gas combined cycle plants can be as high as $160/megawatt-hour (MWh) compared to a LCOE for new coal-fueled plants of up to $90/MWh.*[24]

Projected U.S. coal supplies and consumption.

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[19] Natural gas can be measured based on either its volume (cubic feet) or its heat content (British thermal units or Btu's). Coal can be measured based on either its weight (tons) or its heat content (Btu's). Different units of measurement are sometimes used in different reports. Typically, gas and coal are compared in millions of Btu's (MMBtu). However, gas quantities are sometimes expressed in thousands of cubic feet (Mcf) or trillions of cubic feet (Tcf), rather than MMBtu. On average 1 Mcf of natural gas equals 1,031 MMBtu.

[20] EIA *Electric Power Monthly*, January 2010. Monetary values are expressed in nominal dollars.

[21] EIA *Annual Energy Outlook 2010 ("AEO 2010"),* release date December 2009. Prices are expressed in 2008$ per MMBtu.

[22] *Ibid.* Coal and gas prices for electric power sector. Prices are expressed in 2008 $/MMBtu.

[23] EIA *Natural Gas Prices*, release date January 29, 2010. Also, AEO 2010.

[24] *America's Energy Future: Technology and Transformation,* National Academy of Sciences, October 2009. Cost of electricity is expressed in 2007 dollars.

- *EIA estimates that U.S. recoverable reserves of coal totaled over 262 billion tons in 2008.*[25]
- *At the current rate of consumption, the U.S. is capable of meeting domestic demand for coal for 234 years (262 billion tons/1.12 billion tons of coal consumed in 2008).*[26]

Projected U.S. natural gas supplies and consumption.

- *Estimates of the U.S. 100-year supply of natural gas range from 1,747 Tcf to 2,074 Tcf. According to the Potential Gas Committee, the U.S. has "a total available future supply [of natural gas] of 2,074 Tcf." Other estimates of domestic gas reserves include EIA (755 Tcf)*[27] *and the National Petroleum Council (1,779 Tcf in its 2007 report).*
- *According to EIA, natural gas consumption in 2008 was 23.25 Tcf. At this rate of consumption, U.S gas reserves would be sufficient to last for approximately 89 years (2,074 Tcf/23.25 Tcf per year) using the Potential Gas Committee estimate.*

The projected cost of generating base load electricity by means of a natural gas-fired EGU is in the range of $0.10/kWh[28]*, as compared to the projected $0.061/kWh*[29] *for the PC-fired H2.*

Although the use of natural gas at H2 is necessary as an adjunct fuel for purposes of startup and flame stabilization, it cannot be effectively used as a primary fuel source in an SCPC steam generator to generate the required output. Using natural gas as a primary fuel to fire an 895 MW steam generator at Holcomb 2 is not as simple as firing natural gas into the primary furnace of the unit.

An NGCC unit requires a number of processes and components that either do not exist in a SCPC plant, or are significantly different from those in an SCPC plant. These include: improvements to the overall natural gas delivery system;[30] *a secondary fuel source that would be necessary when the large volume of natural gas required would be unavailable;*[31] *different air pollution control technology equipment for both primary and secondary fuel; combined cycle combustion turbines with relatively short stacks; smaller heat recovery steam generators;*[32] *lower pressure condensing steam turbine generators; and other auxiliary and ancillary equipment. None of this equipment, at least by size or type, is utilized in a PC facility.*

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[25] EIA website *Energy in Brief*, January 25, 2010.
[26] Coal consumption of 1.12 billion tons in 2008 taken from AEO 2010.
[27] EIA Natural Gas Reserve Summary as of Dec. 31, 2008
[28] See 2010 Integrated Resource Plan: http://www.sunflower.net/documents/2010IRPdraftv4.pdf
[29] See Holcomb Expansion Study: Coal Technology Selection Update: June 18, 2010.
[30] While the local Holcomb site railroad facilities are adequate for the H2 unit, a substantial upgrade is required to allow the uninterrupted delivery of coal for H2. A similar series for natural gas delivery upgrades might be expected. These improvements have not been evaluated.
[31] Unlike coal storage on site for SCPC, the large volumes of natural gas required for sustained operation of an NGCC unit constructed as a base-load facility cannot be stored at the site. Historically, large storage tanks of a suitable backup fuel, like #2 fuel oil, would be co-located as a backup fuel source.
[32] Items underlined are not found in a modern SCPC unit. Items not underlined are very different than equipment using a similar name in an SCPC unit.

Conversely, an SCPC unit includes critical process steps and components not found in an NGCC unit. H2 will utilize much of the existing facility infrastructure that was originally designed to accommodate it. In contrast, the addition of an NGCC EGU to Holcomb Station would require major modifications of infrastructure and ancillary support facilities, contrary to the basic concept of Holcomb Station.

For Sunflower to switch from coal to natural gas as base-load fuel for generation of electricity at H2 is not as simple as switching fuels. Rather, to efficiently use natural gas as the primary fuel for H2, Sunflower would be required to completely re-design the EGU to be utilized in its Expansion Project. That constitutes "redefining the source" and it is neither required as a matter of law nor consistent with Sunflower's right to choose the generation technology that best suits its needs.

USPC
As for "innovative combustion techniques" (USPC), see KDHE Response to Comment 1.

Comment 40 (SC Comment VI.B):

The permit limits for startup and shutdown are inadequate.

KDHE Response:

KDHE has revised the permit to clarify the requirements that are applicable during periods of startup and shutdown based on the BACT analysis performed by Sunflower for such periods and discussed in Part 4.0 of the Application, as updated. BACT was evaluated for periods of startup and shutdown of H2. Emissions limitations were modified to address such periods based on the operability of the control technologies and the ability to measure emissions during such periods. Please refer to KDHE Responses to Comment 7, 61, 62, 65, and 67, which address the specific comments related to startup and shutdown raised by Dr. Sahu, for additional information on this topic.

H2 is designed as a base load facility and, as such, startup and shutdown of H2 should be infrequent. For baseload units, there is no requirement to limit hours of startup and shutdown. Limiting hours of startup and shutdown is not feasible. The end of startup and the beginning of shutdown are dependent on control device temperature, rather than on the time it takes to complete the process. The time it takes for the inlet to the control device to reach the temperature required to initiate or terminate control device operations depends on how long the unit has been shut down.

Comment 41 (SC Comment VI.C):

The Permit inappropriately fails to include necessary emissions limitations and contains numerous clearly inadequate BACT determinations.

KDHE Response:

Sunflower did not rely on the existing technology at H1 to justify the BACT determinations for H2. The only pollutant for which a cost-effectiveness determination was required, as part of the BACT analysis, was SO_2. For other pollutants, the top control technology was selected; and a cost effectiveness calculation was not required as part of the BACT analysis.

While the BACT analysis does describe synergies and potential cost savings by utilizing the same SO_2 technology for H2 as used by H1, the cost effectiveness comparison of Wet and Dry FGD presented in Table 4-18 of the BACT analysis did not make adjustments for these potential cost savings. The Coal Utility Environmental Cost (CUECOST) model issued by EPA was used to develop the capital and O&M cost estimates for each FGD technology. The model results were not adjusted for potential cost savings at H2 due to existing infrastructure currently in place for H1.

Please refer to KDHE's Responses to Comments 84, 85, 86, and 87 addressing Dr. Sahu's comments on the BACT determinations as referenced by this comment.

Comment 42. (SC Comment VII. A. 1.)

The permit must contain a 1-hour mass SO_2 emission limit in order to demonstrate that Sunflower will not cause or contribute to violations of the 1-hour SO_2 NAAQS. The permit must include an SO_2 emission limit of 4,089 lb/hr, which is the emission rate that Sunflower used in the modeling to demonstrate compliance with the 1-hour SO2 NAAQS. In coming up with this emission rate, Sunflower ignored the inevitability that their FGD will malfunction. Rather the 4,089 lb/hour emission level is based on only 1 of 3 modules being out for routine maintenance and assumes 1/3 of flue gas would pass through the "off" module. This emission rate is based on an assumed maximum heat input of 8700 mmbtu/hour, even though this is not an enforceable limit.

Past performance at other coal fired power plants demonstrates that it is very likely that Holcomb 2 will occasionally operate at above its nominal maximum heat input rate.

KDHE Response:

Please refer to III. Section A. The CAA does not require KDHE to implement the new regulatory requirements (1-hour SO_2 NAAQS).

A permit condition has been added to address 1-hour SO_2 emissions. If the total SO_2 emissions from H2 exceed 4089 lb/hour during any 1-hour period, the facility is required to notify KDHE, and could be required to conduct an air dispersion modeling analysis.

Kansas has no requirement to consider malfunction emissions when modeling point sources. K.A.R. 28-19-350(d) adopts by reference 40 CFR Part 51 Appendix W, the Guideline on Air Quality Models. Appendix W §8.1.2 recommends modeling point sources using, at a minimum, the design capacity. Malfunctions which may result in excess emissions are not

considered to be a normal operating condition, and should not be considered in determining allowable emissions. FGD malfunctions are not considered to be normal operating conditions, and were not considered in modeling or determining allowable emissions. Scrubber maintenance was considered in modeling and determining allowable emissions.

Even if H2 operates above its nominal heat input rate, emissions are expected to remain less than 4089 lb/hour, an emission rate that exceeds the normal expected emission rate and is representative of a worst case expected emission rate.

Comment 42. (SC Comment VII. A. 2.) cont'd:

The permit must contain a 1-hour mass NO_x emission limit in order to demonstrate that Sunflower will not cause or contribute to violations of the 1-hour NO_2 NAAQS. The Permit must include a 1-hour mass NO_x emission limit of 1,740 lb/hour, which is the emission rate that Sunflower used in modeling to demonstrate compliance with the 1-hour NO_2 NAAQS. In addition, the Permit must limit the NO_2/NO_x ratio to 0.05 as this was also used in the modeling.

The permit must also contain an emission limit of 7.2 lb/hour based on a 1-hour average time that applies all the time for the H2 Auxiliary Boiler, 1.88 lb/hour for the H2 Emergency Diesel Generator, and 2.31 lb/hour for the H2 DFP Booster Pump.

KDHE Response:

Please refer to Section III.A. The CAA does not require KDHE to implement the new regulatory requirements contained in this comment (1 hour NO_2 NAAQS).

The permit contains a requirement that emissions during startup and shutdown be limited to an average of 1740 lb/hour NO_x as determined on each individual startup or shutdown event.

In addition, if the NO_x 1740 lb/hour limit is exceeded during any 1-hour period, the facility is required to notify KDHE, and may be required to conduct an air dispersion modeling analysis.

The NO_2/NO_x ratio of 0.05 comes from AP-42, Fifth Edition, Volume 1, Table 1.1-3 Emission Factors for SO_x, NO_x, and CO From Bituminous and Subbituminous Coal Combustion. A footnote to Table 1.1-3 states that generally, 95 volume % or more of NO_x present in combustion exhaust will be in the form of NO, and the remainder will be in the form of NO_2. In the absence of other more accurate data, KDHE finds information from AP-42 to be acceptable. The NO_2/NO_x ratio of 0.05 is also supported by limited actual operating data from the H1 steam generating unit, and is representative of expected operation of H2.

The permit contains a NO_x limit for the H2 Auxiliary Boiler of 0.036 lb/mmbtu that is equivalent to 7.2 lb/hr:

$$200 \text{ MMBtu/hr} \times 0.036 \text{ lb/ MMBtu limit} = 7.2 \text{ lb/hr } NO_x$$

The permit contains a limit for the H2 emergency diesel generator of 0.50 grams/ horsepower-hour, which equates to 1.88 lb/hour:

1709 BHP x 0.50 g/bhp-hr = 1.884 lb/hr NO_x

The permit contains a limit for the H2 DFP booster pump of 3.0 grams/horsepower-hour, which equates to 2.31 lb/hour:

350 BHP x 3g/bhp-hr = 2.31 lb/hr NO_x

Comment 42. (SC Comment VII. A. 3.) cont'd:

The 1-Hour SO_2 and NO_x emission limits must apply at all times, including startup, shutdown and malfunction. The Draft Permit claims that K.A.R. 28-19-11 is an applicable regulation, although it states "as applied to State regulations K.A.R. 28-19-30 through K.A.R. 28-19-32 and K.A.R. 28- 19-650." The Permit should explicitly state that K.A.R. 28-19-11 does not apply to the BACT emission limits and emission limits included to assure compliance with ambient air quality standards.

KDHE Response:

Please refer to Section III.A. The CAA does not require KDHE to implement the new regulatory requirements contained in this comment (1 hour NO_2 *and 1 hour* SO_2 *NAAQS).*

The permit states that K.A.R. 28-19-11 applies only to K.A.R. 28-19-30 through K.A.R. 28-19-32 and K.A.R. 28- 19-650. Additional statements of applicability of K.A.R. 28-19-11 are not required. The commenter's statement that K.A.R. 28-19-11 does not apply to BACT limits is correct.

The permit limits and/or conditions do apply during startup and shutdown conditions, as stated in existing and revised permit conditions. The permit contains a NO_x *limit during startup and shutdown of an average of 1740 lb/hour as determined on each individual startup or shutdown event. The permit contains an* SO_2 *emission limit of 3239 ton, 12 month rolling average, during periods of startup and shutdown.*

There is no requirement to include malfunctions in allowable emission limits. K.A.R. 28-19-350(d) adopts by reference 40 CFR Part 51 Appendix W, the Guideline on Air Quality Models. Appendix W §8.1.2 recommends modeling point sources using, at a minimum, the design capacity. Malfunctions which may result in excess emissions are not considered to be a normal operating condition, and should not be considered in determining allowable emissions.

The permit also contains a requirement that emissions during startup and shutdown be limited to an average of 1740 lb/hour NO_x *as determined on each individual startup or shutdown event.*

In addition, if the NO_x 1740 lb/hour limit is exceeded during any 1-hour period, the facility is required to notify KDHE, and could be required to conduct an air dispersion modeling analysis.

If the total SO_2 emissions from H2 exceed 4089 lb/hour during any 1-hour period, the facility is required to notify KDHE, and could be required to conduct an air dispersion modeling analysis.

Comment 42. (SC Comment VII. A. 4.) cont'd:

The permit must require continuous monitoring to assure that the 1-hour mass emission limits are met at all times. The Draft Permit provides: the reference test methods and procedures outlined in K.A.R. 28-19-212 and 40 C.F.R. §60.48Da shall be used to demonstrate compliance with the limitations and conditions set forth in this permit.

40 C.F.R. § 60.48Da(h) allows data substitution pursuant to section 7 of Method 19 if the minimum quantity of emission data as required by Sec. 60.49Da are not obtained. Furthermore, 40 C.F.R. § 60.49Da(f)(2) only requires the source to obtain data for 90 percent of all operating hours for each 30 successive boiler operating days. There are numerous other provisions in the NSPS regulations that Sunflower may argue in the future do not require it to monitor and report hourly mass emissions for every hour of operation. But Holcomb 2 must be required to comply with its mass based emission limits for SO_2 and NO_x at all times. Therefore, the Permit needs an additional condition requiring that operation and recording of mass hourly SO_2 and NO_x emissions at all times.

KDHE Response:

Please refer to Section III.A. The CAA does not require KDHE to implement the new regulatory requirements contained in this comment (1 hour NO_2 and 1 hour SO_2 NAAQS).

SO_2 and NO_x emissions from H2 will be continuously monitored by the use of CEMS. EPA has recognized that CEMS may not always be operational and has provided regulatory requirements to address such occurrences. KDHE is not aware of any monitoring system that would not be susceptible to periods of inoperability, and the commenter has not identified any such system. The SO_2 and NO_x CEMS required by the permit, along with the procedures for addressing missing data, satisfy the requirement to monitor the hourly SO_2 and NO_x emissions rates.

The monitoring provisions in 40 CFR Part 60 are sufficient for demonstrating compliance with the emission limits. There is no regulatory basis for demonstrating compliance with more stringent data collection requirements beyond the conditions of 40 CFR Part 60.

Comment 42. (SC Comment VII. A. 5.) cont'd:

The permit must also include enforceable, 1-hour mass emission limits for SO_2 and NO_x for Holcomb 1. An emission rate of 1626.72 lb/hour of SO_2 was used for Holcomb 1. The application and the Air Quality Impacts Analysis Review do not explain where that emission rate comes from. However, actual emissions for Holcomb 1 can be and are much higher. For example, on July 20, 2009 at hour 7, the emission rate from Holcomb 1 was 2086.2 lb/hr. Thus, because the applicant used an emission rate that does not reflect the worst case scenario, much less actual emissions, the Applicant has failed to establish that Holcomb 2 will not cause or contribute to a violation of the new SO_2 NAAQS unless KDHE imposes a fully enforceable emission limit of 1626.72 lb/hour based on a 1-hour averaging time that applies every hour. Similarly, Sunflower relied on a NO_x emission rate of 1,814.5 lb/hour for Holcomb 1. Thus, the Permit must contain a 1-hour averaging time emission rate of 1,814.5 lb/hour for Holcomb 1 that applies all the time. Similarly, the permit must include an emission limit of 8.09 lb/hour for the H1 auxiliary boiler, 19.2 lb/hour for the H1 emergency generator and 2.31 lb/hour for the H1 fire pump.

KDHE Response:

Please refer to Section III. A and the KDHE Response to Comment 15. The CAA does not require KDHE to implement the new regulatory requirements contained in this comment (1-hour SO_2 and NO_2 NAAQS).

There is no regulatory provision that requires permit limitations on existing sources at Holcomb Station due to the 1-hour SO_2 and NO_2 new NAAQS. Changes to the existing source will be dealt with through modifications to the existing source permit or through regional or national rulemaking, such as Clean Air Visibility Rule and Clean Air Transport Rule.

Comment 43 (SC Comment VII.B):

KDHE states that it used a significant impact level ("SIL") of 10 ug/m^3 for both the 1-hour NO_x and 1-hour SO_2 NAAQS. KDHE does not provide any justification for the chosen SIL. This NO_x SIL is higher than the 4 ppb SIL recommended by U.S. EPA in its June 28, 2010 Memorandum entitled General Guidance for Implementing the 1-hour NO_2 National Ambient Air Quality Standard in Prevention of Significant Deterioration Permits, Including an Interim 1-hour NO_2 Significant Impact Level. Furthermore, KDHE fails to include any justification in the record for this NO_x SIL, despite the fact that U.S. EPA's guidance says that such a justification must be included in the record. Sunflower does claim that it used the U.S. EPA proposed 7.5 ug/m^3 SIL. This contradiction needs to be explained and corrected with an additional opportunity for the public to comment on this issue. However, for SO_2, there is no contradiction. Both the Applicant and KDHE state that they used 10 ug/m^3. However, U.S. EPA has recommended a SIL of 3 ppb which equates to 7.8 ug/m^3. KDHE has failed to provide any justification in the record for the 10 ug/m^3 SIL. Therefore, KDHE should require Sunflower to redo its SO_2 modeling to use a SIL of 7.8 and should include the justification U.S. EPA put in its memorandum on the topic.

KDHE Response:

Please refer to Section III. A (1-hour SO_2 and NO_2 NAAQS).

KDHE issued a memorandum on September 22, 2010 announcing interim SILs for 1-hour NO_2, 1-hour SO_2, 24-hr $PM_{2.5}$ and annual $PM_{2.5}$: 10 ug/m^3 for both 1-hour NO_2 and 1-hour SO_2; 5 ug/m^3 for 24-hr $PM_{2.5}$; 1 ug/m^3 for annual $PM_{2.5}$. This memorandum is a part of the public record and was provided to several commenters. The memorandum outlined a detailed methodology and rationale for selecting the SILs which KDHE is now using as interim SILs until such time as final SILs are promulgated by EPA and subsequently incorporated into the Kansas SIP.

Sunflower used a lower, more conservative SIL for NO_2 than the SIL established by KDHE in the September 22, 2010 memorandum.

Comment 44 (SC Comment VII.C):

The Draft Permit provides: During construction, the operator or the owner's constructor is authorized to bring on site and operate such temporary engines as are necessary to support construction activities. All engines will be certified pursuant to the applicable stationary engine standards and will be removed at the completion of construction activities. During construction the auxiliary boiler is authorized to be utilized without the fuel consumption limitation that otherwise applies in this permit. Temporary certified continuous emission monitoring systems (CEMs) will be used to monitor auxiliary boiler emissions during the construction period. The construction period expires when H2 commences commercial operation. However, the application does not demonstrate and the permitting documents do not discuss whether the construction equipment will cause a violation of the 1-hour NO_x and SO_2 NAAQS. Considering the size of this construction project, the low release height of the diesel engines which will be used during construction and the fact that these sources do not have pollution control equipment requirements designed to ensure compliance with the new NAAQS, it is very likely that there will be violations of the NAAQS during construction. The Permit cannot be issued until the applicant demonstrates otherwise.

KDHE Response:

The construction equipment that will be used in the process of developing Holcomb 2 will include several cranes, trucks, tractors, and other heavy equipment that will not remain stationary on site, but instead will be moved to various locations as work dictates. This equipment is not required to be considered for air quality demonstrations for two reasons.

First, the equipment is considered to be "non-road" mobile equipment, and as such, is not included in a PSD analysis. See In re: Cardinal FG Company, PSD Appeal No. 04-04, 2005 EPA App. LEXIS 6 (March 22, 2005). In that case, the Washington Department of Ecology (WDOE) issued a PSD construction permit allowing Cardinal FG Company to build a flat glass production plant. As part of the permitting decision making, WDOE also concluded

that a "trackmobile" that would be used to move train cars around the grounds of the facility was not subject to review and permitting under the PSD program, because it was not a stationary source.

The EAB held that WDOE correctly determined that the trackmobile was not subject to PSD review because it did not fall within the statutory definition of "stationary source" under CAA § 302(z), 42 U.S.C. § 7602(z).

Second, emissions from the construction-related equipment will only be present during the construction of the project. Where a state has a SIP in place, 40 CFR 52.21 (i)(3) (incorporated by reference into KDHE's SIP-approved program) exempts from the impact analyses otherwise required under 52.21(k), (m), and (o) temporary emissions that would not impact any Class I area or any area where an applicable increment is known to be violated. The NSR Workshop Manual refers to these, stating that (1) regarding the impacts analysis: "The EPA allows for the exclusion of temporary emissions (e.g., emissions occurring during the construction phase of a project) when establishing the impact area and conducting the subsequent air quality analysis," and (2) regarding the growth analysis: "Excluded from consideration as associated sources are mobile sources and temporary sources.

Among those provisions at 40 CFR 52.21, 40 CFR 52.21(i)(3) provide that temporary construction emissions are exempt from the impact analysis requirements under 52.21(k), (m) and (o):

> *The requirements of paragraphs (k), (m) and (o) of this section [relating to source impact analysis, air quality analysis, and additional impact analysis] shall not apply to a major stationary source or major modification with respect to a particular pollutant, if the allowable emissions of that pollutant from the source, or the net emissions increase of that pollutant from the modification: (i) Would impact no Class I area and no area where an applicable increment is known to be violated, and (ii) Would be temporary.*

The emissions from the construction equipment that will be brought on site during construction satisfy both of the above conditions. First, it has been demonstrated that the construction of H2 will not impact a Class I area and will not cause or contribute to an exceedance of a PSD increment. Second, the emissions from the construction of the Expansion Project will be temporary.

This indicates that the requirements of paragraphs (k), (m), and (o) do not apply. Specifically, paragraph (k) deals with the source impact analysis (modeling):

> *(k) Source impact analysis. The owner or operator of the proposed source or modification shall demonstrate that allowable emission increases from the proposed source or modification, in conjunction with all other applicable emissions increases or reductions (including secondary emissions), would not cause or contribute to air pollution in violation of: (1) Any national ambient air quality standard in any air quality control region; or (2) Any applicable maximum allowable increase over the baseline concentration in any area.*

As the temporary equipment during construction falls under the exemption, a paragraph (k) modeling demonstrating is not required.

Comment 45. (SC Comment VII. D. 1.)

Sunflower Has Not Demonstrated That It Will Not Cause or Contribute to the Admitted NOx NAAQS Violations. In explaining how it tried to demonstrate that Holcomb 1 and related sources did not cause or contribute to any of the admitted thousands of violations of the 1-hour NO_x NAAQS, Sunflower states: The 40 post-processor outputs in each meteorological year were then recombined into a single file, with the data contained in each file being the 8th highest daily 1- hour maximum concentration at each receptor. Sunflower goes on to clarify that "For a given receptor, three hours (one hour in each year) needed to be examined." Thus, Sunflower admits that it ignored the 1st through 7th highest 1-hour daily maximum values at receptors where there are admitted violations in terms of seeing if Holcomb 2 and related new emission sources contributed to those values. Not only did Sunflower fail to consider whether Holcomb 2 and related new emission sources contributed to the 1st through 7th highest 1-hour daily maximum values at above the significant impact level, Sunflower did not reveal whether Holcomb 2 significantly contributed to or caused any individual 8th highest 1-hour daily maximum value. Sunflower stated: A secondary analysis was needed to determine the contribution from the new sources proposed to be installed for the Expansion Project and demonstrate that they did not have a 3-year average concentration at any of these receptors in excess of the 7.5 $\mu g/m^3$ SIL.

Sunflower does not explain where it came up with this idea of using a three-year average to see if Holcomb 2 and related new emission units were responsible for a significant contribution. Such an approach runs counter to the plain meaning of cause or contribute. Contribution, by its plain meaning, is whether the "New" group significantly contributed to any of the violating receptors during any one hour of the 24 hours that make up the 1-8th high in the three years. If the New Group contributed above 7.5 to any of these hours, then the New Source Group is likewise significantly contributing to or causing a violation because without that contribution, the 8th high would be something less than it was. The regulation prohibits causing or contributing to a violation, not causing or contributing to the design value. Therefore, if, for example, the 9th high daily maximum value in a given year would cause a violation, Sunflower must also examine the New Source Groups' contribution to that violation. The same issue existing with regard to SO_2, although Sunflower relied upon the 4th highest rather than the 8th highest as for NO_x.

KDHE Response:

Please refer to Section III. A (1-hour NO_2 NAAQS).

The 3-year averaging methodology was developed due to the lack of initial guidance from EPA regarding 1-hour NAAQS compliance. EPA has since issued guidance for the 1-hour NO_2 and SO_2 NAAQS that specifically requires averaging to be conducted for comparison to the NAAQS. The August 23, 2010 EPA memorandum by Tyler Fox titled Applicability of

Appendix W Modeling Guidance for the 1-hour SO_2, National Ambient Air Quality Standard, states:

> *The 5-year average based on use of NWS data, or an average across one or more years of available site specific data, serves as an unbiased estimate of the 3-year average for purposes of modeling demonstrations of compliance with the NAAQS. Modeling of "rolling 3-year averages," using years 1 through 3, years 2 through 4, and years 3 through 5, is not required.*

Thus, EPA has concluded that rolling 3-year averages are not required; however, this methodology was developed prior to the memo issuance. Using the maximum rolling 3-year average (in lieu of the 5-year average) to determine compliance with the NAAQS is conservative and is more protective of the NAAQS than EPA considers necessary.

The commenter's statement that "[t]he regulation prohibits causing or contributing to a violation, not causing or contributing to the design value" incorrectly interprets how the multi-year statistical nature of the new 1-hour NO_2 and SO_2 standards are accounted for in air quality modeling. The August 23, 2010 EPA memorandum states:

> *[T]he modeled contribution to the cumulative ambient impact assessment for the 1-hour SO_2 standard should follow the form of the standard based on the 99th percentile of the annual distribution of daily maximum 1-hour concentrations averaged across the number of years modeled.*

The NAAQS comparison methodology for NO_2 can be found in a similar EPA memorandum by Tyler Fox dated June 28, 2010, titled Applicability of Appendix W Modeling Guidance for the 1-hour NO_2, National Ambient Air Quality Standard. This document outlines an identical NAAQS comparison methodology both in terms of using the form of the standard (98th percentile for NO_2) and averaging of the impacts for NAAQS comparison.

Due to the multi-year statistical nature of these new 1-hour NAAQS, it is now necessary to do multi-year averaging of modeled impacts in order to determine whether a standard may be violated. Because the standards themselves are in the form of a statistical average instead of a single value, it is not correct to view the 1-hour NAAQS (75 ppb for SO_2 and 100 ppb for NO_2) as "bright-line" values to which each individual 1-hour impact must be compared.

The 1-hour, NO_2 and SO_2 modeling results stated in the Sunflower Air Dispersion Modeling Analysis are the only periods to show predicted violations of the NAAQS. However, those predicted violations are not attributable to the Expansion Project. These methods were developed because no tools were available from EPA to complete this analysis at the time these new NAAQS standards became effective. KDHE has reviewed and concurred with Sunflower's analysis demonstrating compliance with the NAAQS.

Comment 45. (SC Comment VII. D. 2.) cont'd :

The applicant failed to consider if H2 will significantly contribute to violations at loads less than 100%. Sunflower admits that it did not run the "compliance model" at the 25%, 50% or 75% load scenario. Thus, Sunflower has failed to demonstrate that it will not contribute to any NO_x or SO_2 NAAQS violations at levels above the significant impact level. It may be true that the 100% load resulted in the highest impacts from H2 alone. However, that is not the key issue in this modeling exercise. The key issue is whether H2 contributes to any of the thousands of modeled violations. Modeling only at the 100% load does not provide a rational answer to this question. This is so because at loads less than 100%, not only is the emission rate different, the flue gas exit velocity is also different. The different flue gas exit velocity will change the receptor locations of H2's impacts. Presumably, the flue gas exit temperature would also be different at the 25%, 50% and 75% load versus the 100% load, although the Modeling Analysis claims it will be the same. It is hard to understand how the flue gas exit temperature would be the same at the 25% and 50% loads during startup when the boiler is burning natural gas and the FGD and SCR are not engaged. Since there are thousands of modeled violations, Sunflower cannot claim that its contribution will be below the significant impact level at the violating receptors at the lower loads based on H2's impacts at the 100% load. Rather, Sunflower must model at 25%, 50%, and 75% load in the cumulative modeling scenario to determine if H2's significant impacts will coincide with any modeled violations.

KDHE Response:

Please refer to Section III. A (1-hour NO_2 NAAQS).

The reason that Sunflower did not run the partial load scenario in the "compliance model" because they conducted modeling of the H2 steam generator by itself to determine which of the four load points (100%, 75%, 50% or 25%) yielded the highest ambient impacts. The results of the analysis indicated that when the H2 steam generator was modeled at 100% load, the highest ambient impacts were generated. As such, modeling the H2 steam generator at 100% load represents the most conservative modeling scenario.

Table 5-48 further shows that the 1-hour impact from the 100% load case is approximately 21.5% higher than that of the 75% load case for the 1-hour impact. The 100% load case is 50% higher than the 50% load case, and 120.5% higher than the 25% load case. With such a large difference between the maximum impact at 100% load versus all other partial load scenarios, as well as the clear linear relationship between load and impact, it is reasonable to assume that the 100% load case is representative of maximum concentration. This is rational from a physical sense as well, as the 100% case is the scenario with maximum pollutant loading. Looking further at the results of the load-screening analysis reinforces this assumption. Table 5-48 only looks at the overall maximum impact receptor. When 5 year load screening results are averaged on a receptor-by-receptor basis, the results are similar. The 100% load case impacts are larger than the 75% load impacts by an average of 21.9%, greater than the 50% load case by an average of 63.1 %, and greater than the 25% load case by an average of 174.8%. This shows that the relationship of load versus impact

occurs throughout the modeling domain. Additionally, at each of the receptors where the air model predicts a NAAQS violation, the load screening results show that the 100% load case is controlling.

This position was further reinforced by the results of the May (NO_x) and June (SO_2) 1-hour modeling showing the significant differences between the 100% load and the varying lesser loads, KDHE concluded that no additional modeling at lesser loads was warranted.

Sunflower has provided documentation that flue gas exit temperatures did not vary significantly at various loads.

Comment 46. (SC Comment VII. E. 1.)

Sunflower Failed to Obtain Approval From U.S. EPA Region 7 for Use of the PVMRM. Sunflower explains that it used the Plume Volume Molar Ratio Method ("PVMRM") in its AERMOD modeling for determining compliance with the 1-hour NO_x NAAQS. The U.S. EPA recently explained: As noted in Section 5.1.j, EPA is currently testing the PVMRM option to determine its suitability as a refined method. Limited evaluations of PVMRM have been completed, which show encouraging results, but the amount of data currently available is too limited to justify a designation of PVMRM as a refined method for NO_2.

U.S. EPA goes on to note: Recognizing the potential importance of the in-stack NO_2/NO_x ratio for hourly NO_2 compliance demonstrations, we recommend that in-stack ratios used with either the OLM or PVMRM options be justified based on the specific application, i.e., there is no "default" in-stack NO_2/NO_x ratio for either OLM or PVMRM.
…The OLM and PVMRM methods are both available as non-regulatory-default options within the EPA-preferred AERMOD dispersion model (Cimorelli, et al., 2004; EPA, 2004; EPA, 2009). As a result of their non-regulatory-default status, pursuant to Sections 3.1.2.c, 3.2.2.a, and A.l.a(2) of Appendix W, application of AERMOD with the OLM or PVMRM option is no longer considered a "preferred model" and, therefore, requires justification and approval by the Regional Office on a case-by-case basis. Sunflower did not obtain EPA Region 7 approval for this change. Therefore, Sunflower has failed to demonstrate that the source will not cause or contribute to a violation.

KDHE Response:

Please refer to Section III. A (1-hour NO_2 NAAQS).

Please refer to KDHE Response to Comment 27. KDHE concurs with use of PVMRM as the most accurate method of modeling NO_2 emissions from the project.

Comment 46. (SC Comment VII. E. 2.) cont'd:

NO_2/NO_x Ratios. Sunflower claims that its use of a 0.05 NO_2/NO_x emission ratio for H1 and H2 is justified for AP-42. However, AP-42 provides a vague reference to few percent, and this is based on references to a 1978 paper and a 1979 paper. Sunflower also makes a vague

reference to "spot checks performed at the existing H1 unit." Sunflower provides no detailed information about these "spot checks," much less the underlying data. To deviate from the AERMOD default of 10 percent (0.10) Sunflower would need to demonstrate, with reliable data, that the 0.05 emission ratio is appropriate.

KDHE Response:

Please refer to Section III. A (1-hour NO_2 NAAQS).

The NO_2/NO_x ratio of 0.05 comes from AP-42, Fifth Edition, Volume 1, Table 1.1-3 Emission Factors for SO_x, NO_x, and CO From Bituminous and Subbituminous Coal Combustion. A footnote to Table 1.1-3 states that generally, 95 volume % or more of NO_x present in combustion exhaust will be in the form of NO, the rest NO_2. In the absence of other more accurate data, KDHE finds information from AP-42 to be acceptable. The NO_2/ NO_x ratio of 0.05 is also supported by short-term observations of actual operating data from the H1 steam generating unit, and is representative of expected operation of H2.

Comment 47. (SC Comment VII. F):

KDHE Did Not Provide Sufficient Support for Its Background Concentration. The Air Quality Impact Analysis Review shows that KDHE used NO_x background information from the Peck Community Building in Sumner County. KDHE fails to provide any analysis of why this monitor, which is 200 miles away from the source, is representative. KDHE must establish that this ambient monitoring site is representative of the Holcomb site or require Sunflower to gather on-site ambient monitoring data. Furthermore, KDHE used the five-year average of one-hour values to establish the background value to add to the modeled concentration. KDHE does not explain but it appears that it used the 98% maximum hourly value, rather than the high 1-hour value for each year. KDHE offers no explanation for the "watering down" of the background concentration, nor is there one. The air impacts analysis is supposed to provide a reasonable, worst case estimate of impacts. It is reasonable to assume that any given hour's ambient concentration could be equal to the historic worst hour. In contrast, there is no rational relationship between the predicted ambient concentration in any given hour and the 5-year average of the 98% 1-hour value. Therefore, KDHE must use the highest 1-hour value in the 5-year period, 2005 – 2009, which represents the reasonable worst case background in any given hour in the future. For 2005 – 2008, which is the most recent years available on U.S. EPA's AirData web page, this would be 0.036 ppm. The Air Quality Impact Analysis Review shows that KDHE used SO_2 ambient monitoring data from the Cedar Bluff. KDHE used ambient monitoring data from Cedar Bluffs even though SO_2 ambient monitoring data is available from Sumner County monitoring site. The values at the Sumner County monitor site are multiple times higher than at the Cedar Bluff site. If the Sumner County site is representative enough to use for NO_x, then it must also be representative enough to use for SO_2. If it is not representative enough to use for SO_2, then it is not representative enough to use for NO_x. The air impacts analysis cannot "mix and match" data to use the least protective values. Furthermore, as with NO_x, the SO_2 analysis uses a five-year average of a value other than the daily high. We assume the analysis used the 99% hourly values but we should not have to assume. The Air Quality Impacts Analysis Review

does not explain what value was used. Therefore, there should be a new public comment period after the Air Quality Impact Analysis Review is revised to explain what value is used. As explained above, the only rational value to use is the highest 1-hour value during the 5-year period. U.S. EPA has explained that the approach Sunflower has taken of using the 98th and 99th percentile for the background value would "not be protective of the NAAQS." June 28, 2010 Memorandum Applicability of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard at 18.

KDHE Response:

Please refer to Section III. A (1-hour NO_2 and 1 hour SO_2 NAAQS).

The State and Federal regulations and guidance in existence at the time the Holcomb expansion project was reviewed clearly provide KDHE the authority to use existing monitoring data to develop background values for NO_x and SO_2 based on existing monitoring sites. KDHE followed K.A.R. 28-19-350(d), which adopts by reference 40 CFR Part 51 Appendix W, the Guideline on Air Quality Models. Appendix W §8.2.2(c) states "If there are no monitors located in the vicinity of the source, a 'regional site' may be used to determine background. A 'regional site' is one that is located away from the area of interest but is impacted by similar natural and distant man-made sources."

KDHE has the discretion to waive site-specific preconstruction monitoring and allow the use of existing data if it is representative, of sufficient quality, and current. The data used by Sunflower at the direction of KDHE satisfy those criteria. KDHE determined the existing data to be representative consistent with the guidance in the NSR Workshop Manual (page C.18):

> *[T]he 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>.*

Representativeness of a "regional" monitor is evaluated on more than a determination whether a monitor is located in the maximum impact area and near the maximum concentrations from the proposed source and existing sources. Such a determination includes consideration of the regional emission profiles influencing the monitor and the characteristics of the airshed surrounding the monitor (<u>i.e.</u>, rural vs. urban, etc.). The monitors selected for use in the H2 ambient impact analysis are located at sites that are characteristic of air quality across a broad region, including the area where Holcomb Station is located. In western Kansas, there is little industrial activity, and the regional airshed remains consistent across much of the state. The locations of air monitoring stations and the distances from Holcomb Station to these stations were clearly identified.

Both the Peck and Cedar Bluff sites are adequate to be used in developing a reasonable, worst case estimate of the air quality impacts of the proposed Holcomb expansion. The Cedar Bluff monitoring site was used to establish one-hour SO_2 background values. This site

was established by KDHE to provide a regional look at ambient air quality in central and western Kansas and to serve as the Kansas background site. It is the closest monitoring site for SO_2 to the proposed Holcomb expansion project. KDHE has mapped and reviewed the point source emissions inventory and reviewed the number and location of ground level and elevated point sources of SO_2 emissions as part of the original siting of the monitor and as part of the review process for the Holcomb expansion. We have concluded that Cedar Bluff is suitable for use as a one-hour SO_2 background site due to the very limited number of large SO_2 point sources in that part of Kansas and surrounding states.

The Cedar Bluff monitoring site does not have a NO_x monitor, therefore use of an alternate site was evaluated for developing a background value for NO_x. While not as close to the proposed Holcomb expansion as the Cedar Bluff site, the Peck site meets the criteria of providing representative, current data of sufficient quality. It is the closest NO_x monitor to the proposed Holcomb expansion. The Peck monitor provides a regional look at ambient air quality in south central Kansas. It also provides Kansas the opportunity to evaluate pollutants that may be transported into Kansas from Oklahoma and Texas. Using NO_x results from the Peck monitoring site to establish a background value for the Holcomb expansion is a conservative approach as there are NO_x sources upwind from this site.

The combination of using a five year time period along with the 99th and 98th percentile maximum hourly value for establishing the SO_2 and NO_x background concentrations is a technically and legally sound approach. The longer time period takes into consideration more data points and allows for consideration of any variability that occurs through the monitoring period. EPA's guidance calls for the use of the highest concentration for screening modeling. It is reasonable and appropriate to define "background" as in the form of the standard (98th or 99th percentile of the data) for refined modeling

The June 28, 2010 NO_2 guidance the comment references was distributed by EPA after KDHE provided background data to Sunflower. As for SO_2, that guidance was distributed by EPA on August 23, 2010. Preliminary data was provided to BOA permit staff and to Sunflower in the Spring of 2010. The final background concentration table was provided to BOA permit staff on June 15, 2010. The date of the guidance memo noted in the comment was June 28, 2010. Therefore, the NO_2 and SO_2 guidance was not available to KDHE at the time the background data were developed by KDHE.

KDHE used discretion consistent with the guidance in the NSR Workshop Manual, to determine that neither site-specific air monitors nor monitoring data are required for this project.

Comment 48. (SC Comment VIII. A.):

The air quality impacts analysis of ozone significantly underestimates the actual impact of the project. The proposed Holcomb expansion will emit substantial volumes of two ozone precursors: VOCs and NO_x. Independent modeling conducted by the Sierra Club demonstrates that Sunflower's qualitative ozone ambient impact analysis substantially underestimates the project's impacts on ground level ozone. KDHE must require Sunflower

to conduct air quality impact modeling to demonstrate that the proposed expansion project does not contribute to any violations of the ozone NAAQS. EPA is in the process of revising the 8-hour primary and secondary ozone NAAQS to a level within the range of 0.060 to 0.070 parts per million. EPA has committed to finalize this rule by October of 2010. The permit application submitted by Sunflower, however, only evaluates ozone impacts relative to the current NAAQS of 0.075 parts per million. Assuming that the final permit is issued after the effective date of the new NAAQS, the air quality impact analysis for the Holcomb expansion must evaluate whether the project's emissions will cause or contribute to violations of the new, lower 8-hour ozone NAAQS.

Independent CAMx modeling by Khanh T. Tran confirms that Sunflower substantially underestimates the proposed project's impact on ozone at the Trego County monitor and throughout Kansas. Sunflower based its estimate of the impacts of the Holcomb project on modeling conducted in Colorado, and concluded that the maximum potential increase in ozone concentrations that could be attributed to the project is .512 ppb. The Sierra Club modeling, however, demonstrates that the Holcomb expansion will increase ozone concentrations by 1.48 parts per billion at the Trego County monitor – an impact almost three times higher than the .512 ppb increase predicted by Sunflower. The project will also cause increases of 1.65 ppb at the Goodland monitor, and will cause maximum increases of 5.8 ppb in southwest Kansas. These results demonstrate that Sunflower's estimates of the project's impact based on Colorado modeling are not representative of the project's actual impact. KDHE must require Sunflower to model the impacts of the project on ozone concentrations, rather than rely on estimates that dramatically under-predict the air quality impact of the expansion project. Additionally, Sunflower uses the years 2007 through 2009 to calculate a three-year average of 4th highest concentrations of 0.066 ppm at the Trego County monitor. 2008 and 2009, however, were both atypical years – much cooler than average summers led to unusually low ozone concentrations. KDHE must require Sunflower calculate a three-year average baseline using more typical years – such as 2005 through 2007 – to ensure that the Holcomb expansion will not contribute to violations of the NAAQS in the future. Finally, the ozone modeling conducted by Sierra Club demonstrates that the proposed project will contribute to violations of the NAAQS and cause several new violations of the NAAQS, assuming that the NAAQS is lowered to 0.7 or lower. While the project's contribution to these violations is small, the text of the Clean Air Act itself contains an absolute bar on the construction of new sources that will cause or contribute to any violations of the NAAQS. 42 U.S.C. § 7475(a)(3). EPA has not authorized de minimus exceptions to this absolute statutory bar (i.e., there is no "significant impact level" for the 8-hour ozone NAAQS) – nor does EPA have authority to allow violations that Congress has clearly prohibited. Because the proposed Holcomb expansion will cause and contribute to violations of the ozone NAAQS, KDHE may not issue a permit for the project unless and until KDHE and/or Sunflower takes action to mitigate the project's emissions.

KDHE Response:

No revised 8-hour ozone NAAQS has been finalized as of the date of this document.

Mr. Kahn Tran, AMI, prepared comments on ozone impacts associated with the proposed Holcomb expansion project. Mr. Tran received CAMx modeling inputs from KDHE, based on work that was performed by KDHE for a visibility analysis of the proposed project. The underlying data behind the modeling was based on 2002 emissions and was prepared in support of Regional Haze modeling by the CENRAP regional planning organization.

Because of the intended use of the original modeling, for a visibility analysis, the modeling domain and underlying data sets were developed and quality assured for this purpose. When using this modeling dataset and resulting outputs for an ozone evaluation one must consider the limitations of the data and resulting outputs. Specifically, the relatively coarse domain, 36 km in this case, would generally not be used in an ozone analysis, especially in urban environments. In addition, because the data was prepared for visibility, less of an emphasis was placed on quality assuring ozone precursor emissions, especially VOC emissions. In addition, no performance evaluation of the model was performed for ozone in the local area of the proposed project. Based on these facts, the analysis that Mr. Tran performed does not provide results that can accurately predict ozone increases as a result of this project, especially in the urban areas within the state where ozone exceedances generally occur. Without a local performance evaluation for ozone, the conclusions drawn from these modeling results will have a high uncertainty.

Recognizing the limitations and uncertainties outlined above, the Department reviewed the report and analyzed the modeling results. The conclusions of the report provided by Mr. Tran indicate minimal ozone impacts associated with the proposed project for the most important metrics. Using the metric that KDHE considers most relevant, which is contribution from the project to existing exceedances of the NAAQS, the proposed project only added a maximum of 0.0001 ppm ozone at the Peck monitoring site. This would be about 0.15% of 70 ppb, the upper bound of EPA's proposed ozone standard, which is minimal. The monitoring site closest to the proposed source is a historical site at Goodland and the predicted impact during the maximum 8-hr modeled prediction is 0.00149 ppm representing 2% of the predicted impact (note the prediction is < 75 ppb, the current ozone standard). The maximum increase over the entire grid from the project is predicted to be 5.8 ppb, however, this maximum occurs during a period of low ozone predictions in the 40-50 ppb range. KDHE would generally exclude analysis periods with predicted ozone in the 40-50 ppb range. The final metric in the report is new predicted exceedances of the NAAQS across the entire grid. The report identified two grid cells on Julian day 245 where the proposed source added a maximum of 0.00037 ppm ozone. This prediction represents approximately 0.5% of a proposed 70 ppb standard attributed to the proposed source. This is an acceptable impact.

Given the uncertainties associated with the limitations of the modeling dataset coupled with the acceptable impacts predicted from the source during high ozone periods, there is no reason provided in this report that would preclude the project from moving forward as proposed.

Comment 49. (SC Comment VIII. B.):

The applicant-developers did not conduct the required preconstruction monitoring. The application suggests that monitoring results for PM_{10}, $PM_{2.5}$, and SO_2 were taken from existing KDHE monitoring stations in Trego County and Ford County, Kansas. These monitoring stations are 80 miles northeast and 54 miles east of the proposed site, respectively. This is insufficient monitoring. As a prerequisite to obtaining a permit to construct, the Developers must provide KDHE with data about the background ambient air quality in the area that will be impacted by emissions from the new EGU. Specifically, the applicable requirements provide that: Any application for a permit under this section shall contain an analysis of ambient air quality in the area that the major stationary source or major modification would affect for … each pollutant for which [the project] would result in a significant net emission increase … With respect to any such pollutant for which no National Ambient Air Quality Standard exists, the analysis shall contain such air quality monitoring data as the Administrator determines is necessary to assess ambient air quality for that pollutant in any area that the emissions of that pollutant would affect. With respect to each such pollutant [for which a NAAQS exists], the analysis shall contain continuous air quality monitoring data gathered for purposes of determining whether emissions of that pollutant would cause or contribute to a violation of the standard or any maximum allowable increase. In general, the continuous air quality monitoring data that is required shall have been gathered over a period of at least one year and shall represent at least the year preceding receipt of the application, except that, if the Administrator determines that a complete and adequate analysis can be accomplished with monitoring data gathered over a period shorter than one year (but not less than four months), the data that is required shall have been gathered over at least that shorter period. This requires the applicant—the Developers—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)…" Id. Such decision must be based on a determination that the shorter period provides sufficient air quality data "during a time period, or periods, when maximum concentrations can be expected." In other words, if fewer than 12 months are used, the time period of data collection should represent the months of maximum ambient air concentration. An applicant can only avoid collecting site-specific ambient air quality data if valid, sufficient, and representative ambient air quality data exists from regional monitoring stations. This only occurs in very limited circumstances. To be acceptable, such data must be judged by the permitting agency to be representative of the air quality for the area in which the proposed project would construct and operate. Although a State or local agency may have monitored air quality for several years, the data collected by such efforts may not necessarily be adequate for the preconstruction analysis required under PSD. NSR Manual at C.19-C.18. In other words, KDHE must determine that data from regional monitoring stations are representative of ambient air quality at the Holcomb site. This requires KDHE to make specific findings on the record. EPA sets forth three criteria for determining when existing ambient monitoring data is sufficient: (1) monitor location; (2) quality of the data; and (3) "currentness" of the data.

These criteria do not support using existing air quality data for the proposed Holcomb units.

1. Monitor Location

Pursuant to EPA guidance, to use monitoring data from existing ambient air quality monitors to determine baseline air quality for PSD permitting, the data must be representative of three specific areas: (1) the location(s) of maximum concentration increase from the proposed source or modification, (2) the location(s) of the maximum air pollutant concentration from existing sources, and (3) the location(s) of the maximum impact area, i.e., where the maximum pollutant concentration would hypothetically occur based on the combined effect of existing sources and the proposed new source or modification.

EPA concludes that existing air quality data is only representative of these three areas when the proposed source will be located in an area that is generally free from existing point source impacts. When the new or modified source will be located in an area that has multiple air pollution sources and flat terrain, the applicant can only use existing, representative monitoring data that is from (1) a nearby monitoring site, within 10 km of the points of emissions; or (2) from a monitor that is no more than 1 km away from either the maximum air pollutant concentration from existing sources or from the area(s) of combined maximum impact from existing and proposed sources. Notably, the monitoring stations from which the Developers use data are well over 10 km from the Holcomb site and well over 1 km from the point of maximum impact from the facility. Therefore, the existing monitoring data cannot be used and the Developers must collect 12 months of site-specific ambient air quality data. If the existing air quality monitors were located within 10 km of the Holcomb site, the monitoring data could still not be used. The proposed location of Holcomb unit 2 is also a "multisource impact area." There is an existing coal-fired unit (Holcomb unit 1) contributing to air pollution in the area, as well as a number of other area sources, such as concentrated animal feeding operations. If the proposed construction will be in an area of multi-source emissions and in an area of complex terrain, aerodynamic downwash complications, or land/water interface situations, existing data could only be used for PSD purposes if it were collected (1) at the modeled location(s) of the maximum air pollution concentration from existing sources, (2) the location(s) of the maximum concentration increase from the proposed construction, and (3) at the location(s) of the maximum impact area. If the monitor is located at only one of the locations mentioned above and the locations do not coincide, the source would have to monitor the other locations. Id. (emphasis added). In other words, for a site like the Holcomb Generating Station, existing ambient air quality monitoring data can only be used if the existing monitors happen to coincide, exactly, with the areas of highest impact from the new facility, the areas of highest impact from stationary sources in the area, and the areas of highest combined impact from both new and existing sources. This is highly unlikely, especially since the existing air quality monitors are nowhere near the Holcomb site. In summary, the Developers were required to conduct air quality monitoring for at least twelve months prior to submitting its PSD permit application to the KDHE. This was not done and, therefore, the air quality determination is deficient and the permit cannot be issued. 40 C.F.R. §§ 52.21(i) (prohibiting construction unless all requirements of 52.21(j) through (r) are met), 52.21(m)(1) (requiring preconstruction monitoring).

2. Data Quality

Moreover, even if KDHE's distant existing air quality monitors could be used to determine ambient air quality for permitting the modified Holcomb Station, the data must meet the same quality standards that on-site monitoring must meet. Guidelines for PSD at § 2.4.2. At a minimum, this includes: (1) continuous instrumentation monitoring; (2) documented quality control, including calibration, zero and span checks, and control checks; (3) calibration and span gases should be working standards certified by comparison to National Bureau of Standards gaseous Standards Reference Material; (4) minimum 80% data recovery. It is not clear that these data quality requirements were met. Again, even if they were, the monitoring locations must still correspond to the requirements above – including location at the points of maximum impact and maximum ambient air concentration.

3. Data "Currentness"

Additionally, if existing ambient air monitoring data could be used to permit the new unit at Holcomb, the data must be current. This means that the data must have been collected in the most recent three years. It does not appear that this requirement was met. Moreover, using non site-specific air monitor data, from existing KDHE sampling sites, violates the Clean Air Act. The plain language of the Clean Air Act requires site-specific air quality monitoring for every PSD permit application. 42 U.S.C. §§ 7475(e)(1) ("The review provided for in [42 U.S.C. § 7475(a)] shall be preceded by an analysis in accordance with regulations of the Administrator … of the ambient air quality at the proposed site and in areas which may be affected by emissions from such facility for each pollutant …" (emphasis added)), 7475(e)(2) (providing that ambient air monitoring "shall include continuous air quality monitoring data gathered for purposes of determining whether emissions from such facility will exceed the maximum allowable increases or the maximum allowable concentration permitted under this part.") Specifically, the plain language of the Clean Air Act requires that ambient air quality data be collected at and around the site of the new source, and be collected specifically for the purpose of determining whether the source will cause a violation of NAAQS or increment. The Act does not contemplate using ambient air monitoring from a location eighty miles away as a surrogate. The Act's legislative history further indicates that actual, site-specific ambient air quality should be measured at the permittee's site.

KDHE Response:

In regards to monitor location and currentness of data, please refer to Response to Comment 47. The data also satisfy the quality requirements. They were gathered as part of the KDHE ambient air monitoring program under the Division of Environment Quality Management Plan, Part III: Ambient Air Monitoring Standard Operating Procedures and evaluated under Part III: Ambient Air Criteria Pollutants Monitoring Program Quality Assurance Program Plan. These quality assurance procedures are implemented in accordance with 40 CFR Part 58 Appendix A, Quality Assurance Requirements for State and Local Air Monitoring Stations (SLAMs), Special Purpose Monitors (SPMs), and PSD Air Monitoring. Data gathered from

monitors operated in conformance with 40 CFR Part 58 Appendix A are of sufficient quality to satisfy the second criterion.

The data also satisfy the requirement to be current. The updated Part 6.0 of the Application was submitted to KDHE in 2009, and the pre-construction monitoring data are from 2004 through 2008. Sunflower used PM_{10} data for the period of 2004 to 2006, but the use of 2007 and 2008 data would have led to an even lower background concentration. KDHE evaluated Sunflower's data against the 2005 to 2009 data and found that the differences did were inconsequential to the ambient air quality analysis. See also KDHE Response to Comment 108.

Comment 50. (SC Comment VIII. C.) :

The PSD increment and NAAQS emission inventories were deficient. PSD permit applicants are responsible for conducting modeling to demonstrate that they do not exceed the increment unless adequate offsets are produced; do not contribute to violations in other states (under CAA § 126); do not adversely impact a Class I area; and do not produce an unacceptable growth associated air pollution impact.

After the applicant determines the impact area, it must develop emission inventories which are used to perform dispersion modeling for NAAQS and increment analysis. This must include all stationary sources within the region, as well as recently permitted sources that have not yet been constructed. The applicant must also create an increment inventory, which must include data from increment-consuming sources within the impact area; increment-consuming sources outside the impact area that affect increment consumption in the impact area; building dimensions, stack heights, and other factors necessary to determine downwash from increment consuming facilities.

The applicant must determine whether any major sources have increased emissions since the major source baseline date and whether any source, including minor, area, and traffic sources, has increased emissions since the minor source baseline date. It appears that Holcomb unit 1 established the minor source baseline date since it received a PSD permit in 1978 from U.S. EPA. PSD Permit Application p. 1-1; NSR Manual at C.9. Therefore, the emissions from all sources at the Holcomb Station, as well as all increases in emissions from all major, minor and area sources must be included in the modeling for increment consumption. This includes increased emissions from traffic and from concentrated animal feeding operations. However, it does not appear that this was done for the Holcomb unit 2 application. A large number of confined animal feeding operations have been added to the area within 50 km of the Holcomb Station since the minor source baseline date. These operations, some of which are set forth below, emit PM and PM_{10}. None of these area sources are included in the inventory of increment consuming sources in the PSD Application. According to a recent U.S. EPA emission factor, these animal feeding operations emit PM_{10} at a rate of 3.2 tons of PM10 annually per 500 head. See http://www.epa.gov/ttn/chief/ap42/ch09/draft/draftanimalfeed.pdf. At least 15 percent of these PM emissions are smaller than 2.5 microns ($PM_{2.5}$). Id. The 1,080,138 head of cattle located at area sources within 50 km of the Holcomb Station result in PM_{10} emissions of

thousands of tons per year – above the total PM_{10} emissions from all increment consuming sources actually modeled by the applicant.

KDHE Response:

PSD increments are a limit on air quality impacts as defined in 40 CFR 52.21. PSD increments as defined in 40 CFR 52.21 are limits to increases in ambient pollutant concentration over the baseline concentration.

Air dispersion modeling to demonstrate compliance with the NAAQS and PSD Class II increment was conducted in full accordance with federal and state guidelines. Significant impact modeling, refined modeling (i.e., modeling conducted with additional NAAQS and/or increment consuming sources) was conducted for NO_2, SO_2 and PM_{10}. KDHE supplied information for all NAAQS and increment consuming sources within the allotted study area. When determining the nearby sources to include in the inventory, KDHE followed 40 CFR Part 51, Appendix W, §8.2.3.b. (adopted by reference in K.A.R. 28-19-350(d)):

> *All sources expected to cause a significant concentration gradient in the vicinity of the source or sources under consideration for emission limit(s) should be explicitly modeled. The number of such sources is expected to be small except in unusual situations. Owing to both the uniqueness of each modeling situation and the large number of variables involved in identifying nearby sources, no attempt is made here to comprehensively define this term. Rather, identification of nearby sources calls for the exercise of professional judgment by the appropriate reviewing authority...*

Many factors went into KDHE's decision concerning which nearby sources are expected to cause a significant concentration gradient, including availability of accurate emissions data. Although EPA has developed a draft emission factor for animal feedlot operations, it is not final and has not been incorporated into AP-42.

The NAAQS and increment analyses were compiled in conformance with EPA and KDHE guidelines and fulfilled the PSD modeling requirements.

Comment 51. (SC Comment IX.A):

Hazardous air pollutants ("HAPs"), also known as toxic air pollutants or air toxics, are a group of chemicals and compounds that pose the greatest public health concern. According to EPA, exposure to HAPs may result in "an increased chance of getting cancer or experiencing other serious health effects. These health effects can include damage to the immune system, as well as neurological, reproductive (e.g., reduced fertility), developmental, respiratory and other health problems." In addition, documented impacts of HAPs include degrading air, water and soil quality, threatening wildlife and damaging animal and plant habitat.

The Clean Air Act contains a list of HAPs that includes, among others, hydrochloric acid, hydrogen fluoride, antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead,

manganese, mercury, nickel, selenium, sulfuric acid, benzene, polycyclic organic matter, and radionuclides. See 42 U.S.C. § 7412(b).

Coal-fired power plants emit more than 40% of mercury pollution nationwide. Mercury is a potent neurotoxin. Its levels magnify\ or bioconcentrate, as they move up the food chain. A very low concentration of mercury in a water body can lead to very high levels in fish and even higher mercury levels in animals or humans that consume fish. Organic mercury or methylmercury ("MeHG") is the most toxic form of mercury. It is taken up by plant and aquatic life and accumulates in fish. As described by EPA:

> Dietary methylmercury is almost completely absorbed into the blood and distributed to all tissues including the brain; it also readily passes through the placenta to the fetus and fetal brain. EPA has therefore concluded that "mercury emissions from electric utility steam generating units are considered a threat to public health and the environment." Id. at 79,827.

KDHE Response:

Please refer to KDHE Response to Comment G.

Comment 52 (SC Comment IX.B):

Because EPA has yet to promulgate applicable MACT standards for coal-fired power plants, permitting agencies must impose HAPs emissions limits based on a case-by-case MACT analysis. A MACT analysis often results in lower emissions limits than would a BACT analysis for the same pollutant. In establishing BACT, a permitting authority balances the cost of achieving emissions reductions with the environmental impact of pollutant emissions

MACT requirements apply to "major sources" that have the "potential to emit" 10 or more tons per year of any one HAP or 25 or more tons per year of a combination of HAPs. 42 U.S.C. § 7412(a)(1). If a facility's emissions of any HAP meets or exceeds the major source threshold, the facility must obtain a MACT determination for <u>every hazardous air pollutant</u> that it will emit.

A facility may limit its potential to emit HAPs — thereby avoiding "major source" classification — through "physical or operational limitation[s], including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed," only if such limitations are "federally enforceable." See id. When a facility that would otherwise exceed major source thresholds accepts enforceable limitations to reduce emissions below those thresholds, it is termed a "synthetic minor" source.

Because "synthetic minor" status allows a facility to escape the requirement to install MACT for its hazardous air pollutant emissions, it is essential that "the conditions placed on emissions to limit a source's potential to emit are enforceable by EPA and citizens as a <u>legal</u>

and practical matter, thereby providing the public with credible assurances that otherwise major sources are not avoiding applicable requirements of the Act." EPA, Options for Limiting Potential to Emit at 2 (Jan. 25, 1995). Case law is clear that "a proposed facility that is physically capable of emitting major levels of the relevant pollutants is to be considered a major emitting facility under the Act unless there are legally and practicably enforceable mechanisms in place to make certain that the emissions remain below the relevant levels." As in the attached comments of Dr. Sahu, Sunflower's determination that it is a minor or "synthetic minor" source of HAPs does not provide a valid basis for exempting Sunflower from applicable MACT requirements. The HAPs limits on which Sunflower relies to claim synthetic minor status are not adequate for the three reasons identified by Dr. Sahu: they do not constrain Holcomb 2's potential to emit HAPs, they do not include all sources of HAPs, and without continuous monitoring they are not enforceable. Because the HAPs limits proposed by Sunflower are not adequate to limit Sunflower's potential to emit HAPs to synthetic minor source levels, Holcomb 2 is a major source and is subject to MACT. KDHE must conduct a full MACT analysis for Holcomb 2 and must allow the public to comment on this critical analysis.

KDHE Response:

The application of SO_2 and particulate matter BACT control technology on H2 also reduces the level of emissions of HAPs. Based upon testing on the similarly-equipped H1 source, there is no potential that H2, controls considered, will emit any single HAP in an amount equal to or greater than 10 tons annually, and there is no potential that H2, controls considered, will emit HAPs in any combination in an amount equal to or greater than 25 tons annually. Compliance with the HAPs requirements in this permit will verify H2 is not a major source of HAPs and the provisions of Section 112(g)(2)(B) of the Clean Air Act do not apply. The permit contains federally enforceable requirements, such as coal testing, analysis of stack emissions, and monitoring of scrubber operations to ensure Sunflower operates as a minor source.

Major source status, for purpose of applying the "less than 10/25 tons" standards under Section 112(g) is determined on an individual source basis. Sunflower provided information in Appendix L in the updated Application materials, to show potential to emit (post permit) from H2 is below major source thresholds for HAPs.

In Appendix L, Sunflower identified the HAPs emissions measurements on H1 and compared those estimates both to EPA's AP-42 factors and the EPRI Emission Handbook. Sunflower further discussed in Part 1.0 of the updated Application the HAPs emission expected from the H2 unit when extrapolated from H1 test data to take into account the size differences.

Only the process unit (electrical generating unit (EGU)) would be subject to the case-by-case MACT if it is a major source. The replacement Holcomb 1 DFP, the Holcomb 2 DFP booster pump, and the Holcomb 2 emergency generator would not be subject to the case-by-case EGU MACT.

Although not likely, if HAP limits in the permit are exceeded due to excessive malfunction of

the control equipment, KDHE will take enforcement action and require Sunflower to take any necessary steps to return to compliance with HAP rules, which could include reopening the permit.

Since Sunflower is taking limitations to be an area source of HAPs, no additional public notice is necessary.

Comment 53 (SC Comment IX.C):

Even if Holcomb 2, by itself, were not a major source of HAPs (which it is), it is still subject to MACT because Holcomb Station, taken as a whole, is a major source. "Major source" is defined in the Clean Air Act as any "group of stationary sources located within a contiguous area and under common control" that has the potential to emit, "in the aggregate," 10 or more tons per year of any one HAP or 25 or more tons per year of a combination of HAPs. 42 U.S.C. § 7412(a)(1). Under this definition, it is clear that Holcomb Station — including the existing Holcomb 1 unit, the proposed new Holcomb 2 unit, and all auxiliary and associated facilities (material handling equipment, auxiliary boilers, emergency generators, etc.), together constitute a single source. As explained in the attached comments by Dr. Sahu, Holcomb 2 alone has the potential to emit HAPs at levels that make it a major source. However, even if it did not, certainly Holcomb 2 in combination with the other sources (including Holcomb 1) have the potential to emit HAPs above the 10/25 typ threshold; therefore, Holcomb Station is a major source. While existing EPA regulations attempt to limit the applicability of MACT to major sources through a regulatory definition, EPA cannot exempt what the plain language of the Act requires. By adding Holcomb 2 to Holcomb Station, Sunflower is "modify[ing]" and/or "construct[ing] or reconstruct[ing] a major source of hazardous air pollutants," and so must apply MACT limits to all HAPs emitted by Holcomb Station. 42 U.S.C. § 7412(g)(2).

Alternatively, because Holcomb Station will emit hazardous air pollutants at levels that are major, even if federal MACT limits do not apply, KDHE must require the lowest achievable emissions limits for HAPs as part of its obligation to prevent serious injury to health and welfare. K.A.R. 28-19-13. As discussed above, the effects of HAPs are severe and well-established; KDHE must act to ensure that the harms they cause are reduced to the greatest extent possible. As described in the attached expert report by Dr. Sahu, much lower emissions levels are achievable for many HAPs than those proposed by Sunflower – specifically, the mercury limit proposed by Sunflower is much less stringent than limits that are being achieved by many other plants. KDHE must make the emissions limitations for mercury and other HAPs more stringent, in accordance with the levels achieved by other comparable plants, to prevent serious injury to health and the environment. K.A.R. 28-19-13.

KDHE Response:

The CAA Section 112 g (case-by-case MACT) only requires an evaluation of HAPs emissions from a new facility or a reconstruction to an existing facility if the new process or production unit, in and of itself has the potential-to-emit 10 tons per year of any HAP or 25 tons per year

of any combination of HAPs (40 CFR Part 63.40 adopted in K.A.R. 28-19-752a).

Please refer to KDHE Response to Public Comment G regarding health effects of mercury and other hazardous air pollutants.

C. COMMENTS FROM DR. RANAJIT SAHU, PH.D., PREPARED ON BEHALF OF EARTHJUSTICE AND THE SIERRA CLUB (Comments 54-95)

Comment 54 (Dr. Sahu Comment B(a)):

On page 2/22, the size of the unit is described as 895 MW (nominal) and is purposely vague. FN1 note that this is the approximate size of the generating unit, not a reference to gross or net capacity. Why is the unit size not accurately described? For example, emission calculations clearly note that the gross size is 935 MW and that the heat rate is 9,300 Btu/kWh. It appears that the 895 MW refers to the net size of the unit. This should be clearly clarified in the permit.

KDHE Response:

The Permit Summary serves to describe the facility in conventional terms and is sufficiently detailed for this purpose. The rate of the steam generator is based upon the maximum design heat input of the unit. This is listed as 8700 mmBtu/hr.

Comment 55 (Dr. Sahu Comment B(b)):

On page 3/22, the permit notes that "[B]ased upon testing on the similarly equipped Holcomb Unit 1 (H1, the existing unit at the site) source, there is no potential (emphasis added) that H2, controls considered, will emit any single HAP in an amount equal to or greater than 10 tons annually….or HAPs in any combination in an amount equal to or greater than 25 tons annually." The draft permit neglects to discuss how, "actual" emissions (which is what any test provides) can stand in for "potential" emissions, which are the basis for this major source definition. This is a fundamental error made by the KDHE.

KDHE Response:

The CAA at Section 112(a)(1) defines the term "major source" to mean "any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants." Thus, the major source status evaluation is made after all control technology required by the permit has been considered.

The potential-to-emit (PTE) HAPs calculations are based on repeated actual H1 steam generator outlet and stack test values determined using EPA-approved test methods. KDHE has approved the use of test data from H1 to extrapolate to H2 emissions. The PTE is then estimated over a full 8760 hours of operation. The steam generator outlet data that is measured at the air heater outlet position can be used to determine whether the short periods of time when downstream control technology may not be in service might increase the total annual emissions above the major source threshold(s).

Also, see KDHE Response # 95 (Sahu E).

Comment 56 (Dr. Sahu Comment B(c)):

On page 3/22, in the context of establishing mercury limit by a state-only condition, the draft permit notes that the limits (plural) will be met by "…blending various coals or by the injection of powdered activated carbon (PAC) or other sorbent or both." What does the reference to "various coals" mean? How is this consistent with the application which states that H2 will "…utilize the same supplies of approximately 0.5% sulfur western bituminous coal…" or even with the draft permit itself which indicates that the boiler will use "PRB…or other western coal." The question that arises is what coal(s) will be combusted in this facility. Similarly, the reference to "PAC or other sorbent" is vague. How could the limit be established without a detailed consideration of what the specific and different types of sorbents can achieve?

KDHE Response:

Research conducted on H1 confirms that a substantial level of mercury emission reduction can be achieved with a blend of up to about 20 percent Western bituminous coal with PRB coal.

The comment was based on mercury limits that are contained within the draft permit. Flexibility for the control of mercury emissions was intentionally allowed for optimal removal efficiency. Mercury limits will be verified by continuous monitoring.

Comment 57 (Dr. Sahu Comment B(d)):

On page 4/22, Item 1, it is stated that the "[M]aximum design fuel input…shall be 8,700 MMBtu/hr on an average annual basis." This makes no sense. What is noted in this sentence is the heat input and not the fuel input (which is typically in tons/hr). Also, the juxtaposition of "Maximum" and "average annual" makes no sense. The permit should clearly define the maximum hourly heat input as well as an annual average heat input, if that is separately defined. Both should be enforceable parameters.

KDHE Response:

There is no applicable regulatory requirement for limits on the heat input. The permit already contains sufficient limits for assuring compliance. In a recent decision,

Administrator Jackson confirmed that limits on heat input are not required. See In re Louisville Gas & Electric, Petition No. IV-2008-3, Order Responding to Issues Raised in April 28, 2009 and March 2, 2006 Petitions, and Denying in Part and Granting in Part Requests for Objection to Permit, at 46-47, n.39 (2009).

Comment 58 (Dr. Sahu Comment B(e)):

On page 5/22, Item 6, it is noted that the cooling tower will "…be designed with efficient…drift eliminators…." What does "efficient" mean in this context?

KDHE Response:

In the Air Emission Limitations Section of the permit, Item 7, the drift eliminator efficiency is defined as total liquid drift not to exceed 0.0005% of circulating water flow rate.

Comment 59 (Dr. Sahu Comment B(f)):

On page 6/22, Item 1(a), it is noted that H2 will not have to continuously monitor opacity, such as with a Continuous Opacity Monitoring System (COMS) because "…a CMS for PM is to be installed…to demonstrate compliance with filterable particulate matter…." While I agree with the requirement to continuously monitor PM using the CMS, it is true, as noted, that the CMS will only measure filterable PM continuously. KDHE does not explain how only filterable PM is effectively the surrogate for opacity. It cannot. Opacity can be caused by condensable PM emissions, which the filterable CMS will not measure. Thus, there is no basis for not requiring a COMS.

KDHE Response:

Please refer to Section III.A.

It is not necessary to demonstrate that PM is measured as a surrogate for opacity. As referenced by this permit condition, 40 CFR 60.42Da(b) provides that an owner or operator installing a PM CEM is exempt from the opacity NSPS. In addition, 40 CFR 60.48Da(p) further allows the use of a PM CEM as an alternative to meeting the compliance provisions specified at 40 CFR 60.48Da(o) related to opacity:

> *The owner or operator may elect to install, evaluate, maintain, and operate a CEMS measuring PM emissions discharged from the affected facility to the atmosphere and record the output of the system as specified in paragraphs (p)(1) through (p)(8) of this section*

A continuous monitoring system for PM is required to demonstrate compliance with the filterable PM emissions limitation. There is no continuous monitoring system available to monitor PM_{10} or $PM_{2.5}$ alone. This is sufficient to meet the requirements stated above. With respect to condensable PM emissions limitations as related to visible emissions, limits for condensible precursors (e.g., SAM) are established in the permit, which is sufficient to comply.

Comment 60 (Dr. Sahu Comment B(g)):

On page 7/22, Item 2, it is noted that "NSPS limits are subsumed into the BACT emission limitations in this permit." While it is generally true that BACT limits, for the same pollutant, can and should be more stringent than the NSPS limit, it is also true that the NSPS limits are separate legal standards. As such, a facility can be in non-compliance with both applicable BACT and NSPS limits. Thus, the permit should explicitly state all applicable NSPS requirements, since each of these requirements is a separate, applicable legal requirement.

KDHE Response:

It is not KDHE practice to include in a permit NSPS limitations that are subsumed in BACT limits. The permit identifies the NSPS that are applicable to H2 in the permit. It also includes NSPS requirements that are not subsumed such as NSPS Subpart Y requirements for coal handling activities. The facility is required to report both NSPS limits per CFR 60.51Da(b) and BACT limits semi-annually.

Comment 61 (Dr. Sahu Comment B(h)):

On page 7/22, Item 1(a), the NO_x limit of 1740 lb/hr during startup and shutdown equates to a NO_x rate of 0.2 lb/MMBtu or greater (i.e., 0.2 lb/MMBtu if the heat input is at the maximum value of 8,700 MMBtu/hr, which is unlikely during startup). Since the SCR will not be operating during startup, this means that the boiler out NO_x level is 0.2 lb/MMBtu or greater, likely far greater. What is the basis for this assumption? Page 3 of the Draft Permit Summary Sheet notes that the "uncontrolled potential-to-emit" for NO_x is 0.25 lb/MMBtu? Table 4-11 assumes that the LNB+OFA NO_x value is 0.25 lb/MMBtu. How is the 1740 lb/hr value consistent with this 0.25 lb/MMBtu value?

KDHE Response:

The two NO_X emission rates described by Dr. Sahu are not intended to be equivalent emission rates. The uncontrolled potential-to-emit NO_X emission rate of 0.25 lb/MMBtu is a conservative estimate of boiler NO_X emissions during full load operation, prior to control and is utilized to determine pricing per ton of pollutant removed of the various controls used. The NO_X emission limitation during startup and shutdown is 1,740 lb/hr averaged over the startup and shutdown periods. During startup periods, both natural gas and coal will be fired. During both startup and shutdown events, the heat inputs to the boiler will be less than the heat input during full load operation.

Comment 62 (Dr. Sahu Comment B(i)):

On page 7/22, Item 2(a), it is noted, for NO_x, that "startup is concluded 2 hours after the SCR inlet temperature is consistently above 650 F." No technical support is provided for this purposefully vague statement. First, SCR catalysts can operate with good activity (i.e.,

capable of significant NO_x reduction) at temperatures lower than 650 F. So, what is the basis for selecting 650 F and not a lower value? Second, what does "consistently" mean in the statement above? Third, why the need for the extra 2 hours? The goal should be to minimize startup emissions. This vague definition serves to obfuscate and prolong the startup period. It also creates potential enforcement uncertainly. Similarly, the reference to 650 F during the shutdown is also unsupported.

KDHE Response:

The conclusion of the startup period for NO_X is 2 hours after the SCR inlet temperature is consistently above 650 F. The basis for this definition of the end of the start-up period is general guidance provided from original equipment manufacturers (OEMs) of SCR equipment based on previous SCR retrofits. Sunflower will follow the OEM guidance for the SCR equipment that will be installed on H2 for start-up, shutdown, and normal operation of the SCR in order to ensure reliable and safe operation of this equipment. The permit states that "(i)f the equipment vendor specifies a design temperature different than 650 F, then the startup and shutdown temperatures shall be subject to revision in coordination with KDHE". The term "consistently" has been removed from the permit Item 2a.

Comment 63 (Dr. Sahu Comment B(j)):

On page 8/22, Item 2(b)(i), the SO2 limit of 0.085 lb/MMBtu corresponds to a scrubber efficiency of 93.1% or lower, since the maximum uncontrolled SO2 limit is likely around the assumed value of 1.23 lb/MMBtu (see page 11/22). It is 90.56% when the inlet SO2 value is 0.9 lb/MMBtu, per this condition. What is the basis for this range of assumed control efficiency for the SO2 scrubber (namely 90.56% - 93.1%)? What design and operating parameters of the scrubber provide these efficiencies?

KDHE Response:

BACT is an emissions limitation, not a removal efficiency. Please refer to CAA 169(3) and 40 CFR 52.21(b)(12). While that emissions limitation should reflect the removal efficiency achievable by the control technology determined to be BACT, any comparison of removal efficiencies must be on an apples-to-apples basis. See KDHE's Response to Comment 84 .

Comment 64 (Dr. Sahu Comment B(k)):

On page 8/22, Item 2(b)(ii), the SO2 limit of 0.06 lb/MMBtu corresponds to a scrubber efficiency of 93.3%, when the inlet SO2 is at 0.9 lb/MMBtu (the upper limit for this condition). The efficiency will be lower than 93.3% if the inlet SO2 level is lower than 0.9 lb/MMBtu. Again, what is the basis for this range of assumed control efficiency for the SO2 scrubber (namely, a maximum of 93.3%)? What design and operating parameters of the scrubber provide these efficiencies?

KDHE Response:

See KDHE's Response to Comment 63.

Comment 65 (Dr. Sahu Comment B(l)):

On page 8/22, it is noted that, for SO2, startup extends till the fabric filter inlet temperature increases to 225 F and shutdown begins when the fabric filter inlet temperature drops below this temperature. What is the basis for this temperature? How is the fabric filter inlet temperature related to scrubber operation? Is the fabric filter not operational at all times, when there is fire in the boiler? Why not?

KDHE Response:

The basis for this definition of the end of the startup period is general guidance provided from original equipment manufacturers (OEMs) of fabric filter (FF) equipment based on previous SCR retrofits. Sunflower will follow the OEM guidance for all air quality control equipment that will be installed on H2 for startup, shutdown, and normal operation in order to ensure reliable and safe operation of this equipment. The FF will be placed in service at or immediately before a coal fire is established in the furnace.

The relationship between the FF and SO2 temperatures is described in the updated Application (Part 4, Section 4.1.1). In a Dry FGD module, flue gas contacts an alkaline slurry mixture of lime and fly ash to remove SO2 through chemical reactions. In the process the slurry is dried by the flue gas, simultaneously reducing the gas temperature by about 60˚F, to 165˚F. As the reacted product is flash-dried, it forms a powder waste product. The Dry FGD product and fly ash is then collected in the particulate control equipment (usually a fabric filter) located downstream of the Dry FGD. The filter bags become coated with this powder/ash mixture, which contains large amounts of un-reacted alkaline material. At inlet temperatures below 225˚F establishing slurry flow will quickly cause the fabric filter inlet temperature to drop below the dew point, condensing moisture within the fabric filter, coating the bags with muddy ash cake, blinding the bags and requiring excessive maintenance. Placing the Dry FGD in service before reaching the 225˚F temperature will always result in inadequate temperature to allow the fabric filter to remain in service, starting the process over again.

See also KDHE's Response to Comment 67.

Comment 66 (Dr. Sahu Comment B(m)):

On page 8/22 Item 2(c), the filterable PM limit is the same for all sizes of PM – namely PM, PM_{10}, and $PM_{2.5}$. What is the rationale for this? Does this mean that the only form of PM present will be $PM_{2.5}$? If so, what is the basis for this assumption?

KDHE Response:

The emission limits in Item 2(c) are separate and distinct with different performance tests required to determine compliance with the various filterable PM emissions limitations. Because of stack test port availability, these tests will not be conducted simultaneously; nor will they use the same EPA-approved methods.

Filterable PM will be measured by EPA Method 5. This method, the most frequently used means of demonstrating compliance with this limit, affords the highest degree of assurance that the control technology is operating in compliance with the permit emissions limitations.

Filterable PM_{10} and filterable $PM_{2.5}$ compliance will be determined using OTM 27 or EPA Method 201, requiring separate tests at separate times in the same stack ports as those used for PM, using different impact head attachments to differentiate between the target filterable and those particles larger than the target filterable.

The PM CEMS will measure filterable emissions but cannot distinguish among speciated forms of PM. Compliance with all filterable PM emissions limitations are demonstrated on a continuing 30-day rolling average basis by this instrument.

This permit makes no attempt to differentiate among the various filterable PM speciates due to the paucity of information regarding particle size distribution, particularly as this relates to $PM_{2.5}$. As stated in the Application (Part 4, Section 5.2.1.1) as updated, the expectation is that the majority of PM will be PM_{10}, although there is some portion that will be greater than 10 microns. Further, as described in the Application (Part 4, Section 6) there are still substantial technical issues and a lack of data regarding PM2.5.

In the case of Plant Washington, an adjustment was made to the proposed filterable component of PM_{10} based on particulate size distribution data presented in EPA's AP-42. However, EPA indicated in its Trimble Order that utilizing a simple ratio of AP-42 factors or data from a single compliance stack test would not necessarily be sufficient to establish a correlation between PM_{10} and $PM_{2.5}$. Rather, EPA has suggested that to correlate PM_{10} and $PM_{2.5}$, actual test data from a similar unit taking into account variations in operating conditions (e.g., fuel rate, control equipment condition, and operation) is necessary.

Therefore, the H2 PM, PM_{10} and $PM_{2.5}$ emissions limitations are based upon the limited number of $PM_{2.5}$ BACT analyses conducted for coal-fired facilities and a review of limited test data for $PM_{2.5}$ from H1 and other locations. These sources do suggest that all three test determinations have, at last at H1, returned very similar results for each variable.

Comment 67 (Dr. Sahu Comment B(n)):

On page 9/22, why is there need to define startup and shutdown for PM? The proposed PM limit applies to all time periods, including startup and shutdown. If there is a need, what is the basis of the 150 F fabric filter inlet temperature? And, why is this different from the 225 F value used for SO_2 startup and shutdown?

KDHE Response:

The definition of the startup period for fabric filters (FF) is included to document the good air pollution control practices to minimize emissions during startup and shutdown. Work practices are based on placing the FF in service in accordance with the respective manufacturers' recommendations. The basis for this definition of the end of the start up period is general guidance provided from original equipment manufacturers (OEMs) of FF equipment based on previous FF retrofits. Sunflower will follow the OEM guidance for the FF equipment that will be installed on H2 for start-up, shutdown, and normal operation of the SCR in order to ensure reliable and safe operation of this equipment. OEM guidance applies to each separate type of controls and varies as needed to protect the integrity and operability of the equipment. Thus, different operating temperatures are appropriate for the FF and Dry FGD.
The reason the definition of start-up and shut-down for particulate matter only is in the permit is because start-up and shut-down emissions are excluded from NSPS Subpart Da for particulate matter.

Comment 68 (Dr. Sahu Comment B(o)):

On page 9/22, the total PM_{10} and total $PM_{2.5}$ limits are the same. What is the basis? Also, the proposed limit of 0.018 lb/MMBtu can be increased to 0.025 lb/MMBtu if the 0.018 lb/MMBtu value is not "consistently" achievable? What does "consistently" mean, in this context?

KDHE Response:

See KDHE Response to Comment 66 (Sahu B(m)).

"Consistently" has its ordinary meaning, as used in the EAB decisions holding that BACT emissions limitations should be established at levels that can be "consistently" achieved over the life of a facility.

Comment 69 (Dr. Sahu Comment B(p)):

On page 10/22, Item 2(i), it is noted that "[E]missions" of HAPs from H2 shall not exceed 10 tons/yr for any one HAP or 25 tons/yr for any combination of HAPs. What "Emissions" are referred to here – actual or potential? If it is "potential" emissions (as it should be), how does the KDHE propose to demonstrate and ensure compliance? Also, do these HAP emissions refer only to emissions from the boiler or from all sources in the plant that are necessary for H2 to operate? The use of H2 in this condition is vague and incorrect. I provide additional comments regarding this in Section E of my report.

KDHE Response:

The HAPs emissions limitations in the permit reduce the potential to emit by placing restrictions on actual emissions.
Please refer to KDHE Response to Comment 53.

Stack test data will be used to assess and ensure compliance with permit emissions limitations. The permit requires verification of the accuracy of the estimates in the permit application by post-construction stack testing. Additionally, the permit contains effective limits on the H2 PTE, specifically through the application of the Dry FGD and fabric filter; and compliance with these emissions limitations is assured by the permit's monitoring, recordkeeping, and reporting requirements.

The terms H2 and Holcomb 2 are both defined in the Description of Activity Subject to Air Pollution Control Regulations.

Comment 70 (Dr. Sahu Comment B(q)):

On page 16/22, under the Monitoring Requirements, there is no requirement to continuously monitor ammonia emissions. In fact, it is likely that ammonia will be continuously monitored as part of SCR operation. The permit should require the continuous monitoring and reporting of ammonia.

KDHE Response:

Ammonia is not a regulated pollutant. Nor are ammonia emissions limited by the permit. Therefore, there is no basis for requiring that ammonia emissions be monitored, continuously or otherwise, as suggested by the commenter.

Comment 71 (Dr. Sahu Comment B(r)):

On page 17/22, under Recordkeeping, Item 3, what is the basis of the 1/3 FGD inlet and 2/3 stack values for HCl and HF, during "FGD maintenance activities." Also, how are "FGD maintenance" activities defined?

KDHE Response:

As stated in its updated Application (Part 1, Section 4.2), Sunflower examined whether startups, shutdowns, and other scrubber out-of-service events would cause the acid gas HAP emissions (HCl and HF) to exceed the 10 tons per year threshold. The basis of the 1/3 FGD inlet value is the assumption that during a routine atomizer maintenance operation, one-third of the flue gas is "uncontrolled" while the lime slurry spray is discontinued in favor of plain water, to allow for the atomizer to be swapped out for maintenance, which is a routine activity for spray dryer absorbers.

Several different activities described in the Application demonstrate the emission rates that occur during such events and the expected duration of such events. Otherwise, FGD maintenance is a conventional term that does not require specific definition within the permit.

Comment 72 (Dr. Sahu Comment B(s)):

On Page 4 of the Draft Permit Summary Sheet, it is assumed that it may be difficult to simultaneously achieve the NO_x and CO limits as well as the NO_x and VOC limits? What is the technical basis for this assumption?

KDHE Response:

See KDHE's Responses to Comments 82 and 91 (Sahu C1.5 and C6).

Comment 73 (Dr. Sahu Comment B(t)):

On page 5 of the Draft Permit Summary Sheet, in the context of the mercury limit, the assumptions – namely the mean mercury in coal concentration of 0.172 ppm and the 85% reduction (presumably by PAC or other sorbents) – are not supported. Also, the discussion references tests conducted on H1 in 2004. Mercury controls using various PACs available today (not to mention years from now, when H2 is likely to be operational) are far more effective than the 85% assumed by the KDHE. Thus, what is the basis for reliance on the 12 year old (assuming a 2016 start for H28) H1 tests by the KDHE?

KDHE Response:

The percent mercury control efficiency identified on Page 5 of the KDHE Draft Permit Summary Sheet actually corresponds to a 90% reduction in mercury based on the mean value of all coal samples in the USGS database, not the 85% indicated (http://energy.er.usgs.gov/coalqual.htm). The mean of all U.S. coal samples is 0.180 ppm, with 0.172 being the mean of all samples less one outlier. Further, the mean of all PRB coal in the USGS database is 0.100 ppm; and the mean mercury concentration of all Colorado coal is 0.078 ppm. To establish a mercury emissions limitation that would apply regardless of the origin of the coal, KDHE selected the 0.180/0.172 ppm mean value.

Accordingly, the 90% reduction applied to the 0.172 ppm mean concentration (less outlier) corresponds to approximately 2.04 lb/TBtu of coal burned, or 0.020 lb/GWh of energy produced. Application of a 90% reduction to the 0.100 ppm mean concentration of PRB coal yields 1.18 lb/TBtu of coal burned, or 0.012 lb/GWh of energy produced. Further, the application of a 90% reduction to the average mercury concentration of the test coals used in the joint H1 test program would yield about 1.00 lb/TBtu, or 0.010 lb/MWh. Also see KDHE's response to Comment 92 (Sahu C7) below.

Comment 74 (Dr. Sahu Comment B(u)):

Attachment B (page 14) of the Permit Summary Sheet notes that three levels of SCR efficiency were considered – namely 60%, 72%, and 80%. This is same as Table 4-11 in the Application. Did the KDHE conduct any independent analysis of SCR capabilities, other than simply accept what was in the application?

KDHE Response:

KDHE conducted a comprehensive analysis of low NO_X burners (LNB) with over-fire air (OFA) plus SCR as BACT for H2 in determining the BACT emission limit. Including a percent NO_X reduction requirement for the SCR in the permit is not necessary, because the NO_X emissions limitation is based on the maximum degree of reduction for the combination of LNB with OFA plus SCR. Compliance with the NO_X emissions limitation will be continuously monitored.

Comment 75 (Dr. Sahu Comment B(v)):

Attachment B (page 15) of the Permit Summary Sheet notes that wet FGD was considered at a removal efficiency of 94%. What is the basis of this statement? It is also stated that "…wet FGD is not normally applied to PRB coals…" What is the basis of this statement? What does "normally" mean? The same paragraph also notes that "…wet FGD is less effective in controlling total particulates, PM10, fine particulates and HAPs…." What type of wet FGD designs did the KDHE evaluate in supporting this statement? What types of operational assumptions underlie this statement? Or, did the KDHE simply state this, without regard to the type, design, and operating conditions of any (of the large number) type of wet FGD? Finally, with regards to wet FGD, the KDHE notes that "...increase in the amount of water necessary for the wet FGD.." Presumably, the KDHE means the increase as incrementally over what the water use will be for the proposed dry FGD. However, this is not a quantitative analysis. What is the actual value (in gallons per minute) of the water increase? And, how does it compare with the overall consumptive water use for H2, including the cooling tower make-up water?

KDHE Response:

The basis for the 94% is what a wet FGD is capable of continuously achieving when burning PRB coal with a sulfur content of 0.5%. The selection of 94% is supported by recently issued permits for PC units firing PRB coal with wet FGD.

See KDHE Response to Comments 84, 85, 86, and 87.

The Dry FGD performs better in controlling fine PM and SAM emissions than does a Wet FGD. This is independent of the particular design of the scrubber. In the Wet FGD, the PM control equipment is located upstream from the Wet FGD absorber. Entrained scrubber slurry and fine SAM aerosols which escape the Wet FGD absorber's mist eliminator contributes to increased PM emissions. In fact, Plant Washington will require sorbent

injection to control fine PM, SAM, and other acid gases. As the commenter acknowledges, sorbent injection would be necessary for the control of acid gases if a Wet FGD is used instead of a Dry FGD. See KDHE Response to Comment 88 (Sahu C3).

Regarding additional water use required for Wet FGD see KDHE Response to Comment C. The required water quality for Dry FGD is such that waste water can be used, while Wet FGD chemistry requires an overall better water quality.

Comment 76 (Dr. Sahu Comment C):

The BACT Emissions Limits Proposed Are Not Correct. Dr. Sahu asserts that Sunflower did not follow a "Top Down" BACT and relied on limited sources of information regarding pollution control technology resulting on a failure to select proper emission control technology and/or selecting a level of control that is incorrect. While comparisons may have a place in the BACT analysis, the determination of BACT is a case-by-case site specific analysis – it is not simply a comparison to similar projects. There is no "similar projects" standard in the BACT definition. Second, Sunflower notes, for example, in discussing the NO_x limit for H2, that "[T]his limitation is consistent with the lowest NO_x emission limitations in recently issued permits." 11 It is not clear what Sunflower means by "…consistent with…" It is clear, however, that "consistent with" is not an appropriate standard in determining BACT. Third, in another instance (in this case PM2.5), Sunflower relies on yet another arbitrary standard to reject limits that have been specified in other permits. Sunflower notes, for example, that the Brayton Point filterable PM2.5 limitation "…has not been demonstrated in practice and is not considered a practically achievable limit…" But, it gives no basis for this statement. Sunflower would have us believe that this source and its regulators simply set this limit without expectation that it will be met. This is simply a transparent ploy to avoid setting a lower limit.

KDHE Response:

The BACT analyses that KDHE conducted was performed consistent with EPA's NSR Workshop Manual. Sunflower conducted a case-by-case site-specific BACT analysis for H2 as shown in Part 4.0 of the Application, as updated. As part of the site-specific analysis, Sunflower considered actual emissions from similar projects and permit determinations. Such consideration is appropriate and consistent with long-standing EPA recommendations for performing a BACT analysis.

EPA guidance recommends that a PSD construction permit applicant review emissions data from existing facilities similar to those proposed as a part of establishing a BACT emission limitation. Sunflower followed this guidance in conducting the BACT analyses for H2. In doing so, Sunflower focused on "similar projects" to assess the emission rates achievable at H2 using the technologies identified during the BACT analysis.

Emissions rate data from existing similar facilities are useful in determining whether a proposed emissions limitation will be achievable at the new source. However, BACT does not require the selection of an emissions rate that has not been rigorously demonstrated to be

achievable, particularly when actual data suggest that the rate would not be achievable over the life of the facility.

Permit writers have discretion to set BACT levels that do not necessarily reflect the highest possible control efficiencies but, will allow permittees to achieve compliance on a consistent basis throughout the life of the facility. The use of a safety factor to take into account variability and fluctuation in expected performance of the pollution control is acceptable.

Emission limitations are applicable for the life of the facility. Therefore, it is appropriate to consider the extent to which available data show the emission rates have been achieved by other facilities in setting the emissions limitations that are BACT for the facility.

Sunflower's BACT analysis considered the emissions limitations determined to be BACT for similar projects. Sunflower determined that the BACT emissions limitations proposed for H2 are consistent with those limitations or demonstrated why those limits or lower limitations were not achievable. In determining BACT for H2, KDHE evaluated Sunflower's BACT analyses and determined BACT for H2 consistent with all applicable regulatory requirements.

Comment 76 (Dr. Sahu Comment C – cont'd):

Dr. Sahu states the process used by Sunflower in conducting the BACT analysis was flawed, the BACT analysis conducted by Sunflower was "backwards-looking" and the applicant did not look at any of the technical literature regarding current performance levels of air pollution technologies.

KDHE Response:

Sunflower prepared and submitted information and documentation for KDHE to consider in determining the appropriate BACT emissions limitations for H2. The BACT analysis for H2 follows EPA's five step "top-down" BACT determination process, which is described in Section 1.3 of the BACT Analysis at Part 4.0 of the Application, as updated. The BACT determinations were conducted on a case-by-case basis taking into consideration, among other things, the achievability of a limitation. Sunflower evaluated the latest proven technologies and compared H2 to similar facilities recently receiving permits and their emissions limitations.
Many of the permit emissions limitations that were considered in the BACT review have yet to be demonstrated, because the plants have not started operations. For that reason, this source of data can be "forward looking" rather than "backward looking" as characterized by Dr. Sahu.

KDHE, as part of the permitting process require applicants to review technical literature regarding the current performance levels of air pollution control technologies. This information, as well as the detailed evaluation of recent emissions data from similar facilities was presented in Sunflower's BACT analyses, used to determine the BACT emissions limitations for each of the pollutants.

Comment 76 (Dr. Sahu Comment C – cont'd):

Without question, as discussed later in Section E of this report, KDHE has an obligation to consider the BACT and MACT limits in the issued Plant Washington permit, before finalizing the permit for H2. And, it is my opinion that a properly conducted BACT analysis for H2 would likely have found that for several pollutants, it is likely that BACT for H2 could be even more stringent than the BACT limits for Plant Washington.

KDHE Response:

As an initial point, the Plant Washington permit includes an annual SO_2 limit of 0.052 lb/MMBtu on a 12-month rolling average, equivalent to 4,316 tons per year. In comparison, the H2 permit includes an annual limit of only 3,239 tons per year.

Plant Washington is not in operation, so compliance with its emissions limitations has not been demonstrated, although Sunflower did evaluate the technical feasibility of meeting the lower NO_X and SO_2 limits in the Plant Washington permit. That permit includes an annual NO_X emission limit of 0.030 lb/MMBtu.

To assess the achievability of the annual 12-month rolling average emission limits for NO_X included in the Plant Washington PSD permit, Sunflower evaluated the emissions data from the best performing existing sources that had previously been identified in the updated BACT analysis. In Part 4 (BACT) at 3.2.1.1. that Sunflower conducted, an evaluation using the same dataset, which consisted of CEMS data from 2005 through 2008, as used for the 30-day rolling average analysis was presented. This dataset is summarized in the following tables.

Table 4. Summary of NO_X Data Analysis

Unit Analyzed	30 Day Rolling Average			12 Month Rolling Average		
	Mean lb/MMBtu	Minimum lb/MMBtu	Maximum lb/MMBtu	Mean lb/MMBtu	Minimum lb/MMBtu	Maximum lb/MMBtu
Havana 6	0.040	0.070	0.022	0.042	0.047	0.034
Hawthorn 5	0.072	0.076	0.067	0.072	0.074	0.071
Pleasant Prairie 1	0.054	0.071	0.036	0.053	0.060	0.047
Springerville 3	0.072	0.083	0.062	0.073	0.074	0.071
TS Newmont	0.041	0.057	0.031	Insufficient Data		
W.A. Parish 6	0.043	0.053	0.031	0.043	0.051	0.038
W.A. Parish 7	0.039	0.053	0.030	0.038	0.042	0.036
Walter Scott 4	0.045	0.064	0.026	0.045	0.052	0.039

Table 5. NO_X Statistical Analysis – Evaluation of Normal Distribution

Unit Analyzed	30 Day Rolling Average			12 Month Rolling Average		
	Number of Averages	Standard Deviation σ	Upper Operating Level lb/MMBtu	Number of Averages	Standard Deviation σ	Upper Operating Level lb/MMBtu
Havana 6	1,286	0.014	0.076	36	0.003	0.049
Hawthorn 5	1,318	0.002	0.077	37	0.001	0.074
Pleasant Prairie 1	598	0.009	0.077	12	0.005	0.065
Springerville 3	751	0.004	0.082	17	0.001	0.075
TS Newmont	220	0.007	0.059	Insufficient Data		
W.A. Parish 6	1,366	0.005	0.056	36	0.004	0.053
W.A. Parish 7	1,363	0.003	0.047	37	0.002	0.043
Walter Scott 4	622	0.010	0.071	9	0.005	0.057

As the data show, the Plant Washington annual 12-month rolling average NO_X emission limit of 0.030 lb/MMBtu has not been demonstrated to be achievable. While the 12-month rolling average maximum lb/MMBtu results may be lower than the corresponding maximum 30-day rolling average results, they are still well above the Plant Washington emission limit of 0.030 lb/MMBtu. The 12-month rolling average results justify the H2 proposed NO_X limit of 0.05 lb/MMBtu on a 30-day rolling average. Only two units, Havana 6 and W.A. Parish 7, have an upper operating level less than 0.05 on a 12-month rolling average basis.

Based on this review of best performing similar sources, Sunflower concluded, and KDHE concurs, that a NO_X emission limitation of less than 0.05 lb/MMBtu is not technically feasible over the life of H2. The BACT emissions limitation for H2 of 0.05 lb/MMBtu on a 30-day rolling average basis is very stringent and has not been continuously achieved by any existing facility.

See KDHE Response to Comment 5.

Comment 77 (Dr. Sahu Comment C1):

The Proposed NO_x Emission Limitation is not BACT. Dr. Sahu states the Permit Summary does not identify what technology option was selected and the SCR NO_x reduction requirement should be included in the permit.

KDHE Response:

The permit identifies the combination of low NO_X burners (LNB) with over-fire air (OFA) plus SCR as BACT for H2. Adding a percent NO_X reduction requirement for the SCR in the permit is not necessary, because the NO_X emissions limitation is based on the maximum degree of reduction for the combination of low NO_X burners with over-fire air plus SCR. Compliance with the NO_X emissions limitation will be continuously monitored. With an enforceable BACT emission limitation, there is no regulatory basis for including a specific SCR NO_X reduction requirement in the permit.

Comment 77 (Dr. Sahu Comment C1 cont'd):

Dr. Sahu states the proposed NO_X emission limit is not BACT. Dr. Sahu states that Sunflower and KDHE should evaluate if a NO_X emission limitation less than 0.05 lb/MMBtu is technically and economically feasible.

KDHE Response:

See KDHE Response to Comment 5.
The selected NO_X BACT for H2 consists of a layered combination of LNB, OFA, and SCR. The NO_X BACT emissions limitation for H2 is based on the maximum degree of reduction for the combination of these technologies. Steam generator vendor NO_X emission rate guarantees are also based on the combination of combustion NO_X controls and SCR. The achievable NO_X emission rate at the SCR inlet will be influenced by the burner configuration (i.e., wall-fired or tangential-fired) as well as operating constraints related to meeting CO and VOC emissions limitations, which will be established during the boiler design phase.

In updating its Application, Sunflower evaluated whether a NO_X emissions limitation lower than 0.05 lb/MMBtu is technically feasible and determined that it is not.[33] *This analysis was submitted to KDHE in response an earlier informal comment by EPA.*

The NO_X BACT emission limitation of 0.05 lb/MMBtu applied over rolling 30-day periods is supported by recent permitting activity for similar sources using similar technology combinations and by actual NO_X emission measurements from best performing operating units utilizing the combination of combustion NO_X controls and SCR. As Sunflower concluded, considering the available data from the nine best NO_X performing sources, including two of the four W.A. Parish units (6 and 7) located in the Houston-Galveston-Brazoria ozone non-attainment area, an emission limit of 0.05 lb/MMBtu on a 30-day rolling average basis is the lowest BACT limit consistently achievable at H2.

Following formal comment by EPA, Sunflower updated this analysis of the W.A. Parish facility. The analysis expands the period from four to five years (2005 thru 2009) and includes all four large units at W.A. Parish (units 5 through 8). The outcome is unchanged.

Comment 77 (Dr. Sahu Comment C1 cont'd):

Dr. Sahu questions how KDHE can conduct a technical review of the application without engineering details on the NO_x control system.

KDHE Response:

Details of the NO_X control system that the commenter is requesting will be established at later stages of project development. Normally, detailed specification and design of the equipment to be included in a new power plant proceeds after the receipt of a construction

[33] See Appendix M of the updated application materials.

permit. Requiring engineering design details of the emission control equipment to be a condition of the permit unreasonably limits the ability of the owner at later stages of the project to incorporate the latest technological developments into the engineering, procurement, and construction of the project. The engineering details requested are not needed to complete the BACT analysis.

Comment 78 (Dr. Sahu Comment C1.1):

The application states, without any support, that the boiler-out NO_x level will be 0.25 lb/MMBtu. This is wrong. Numerous PRB-fired coal boilers, currently operating (and operating since the last five years) have much lower boiler out NO_x emission rates. In any case, there is absolutely no support for the contention that the boiler out NO_x emissions levels, with the LNB+OFA will be as high as 0.25 lb/MMBtu. Rather, it should be closer to 0.10 lb/MMBtu on a 30-day average basis, especially for a properly run, baseload unit, like H2.

KDHE Response:

This commenter's data show that for select facilities without an SCR but including other NO_x controls (such as low-NO_x burners and overfire air) are achieving average monthly emission rates less than the 0.20 lb/MMBtu (Dr. Sahu incorrectly used 0.25 lb/MMBtu which is the uncontrolled baseline rate used for the cost analysis) assumed by Sunflower as the steam generator outlet rate for H2. According to the commenter, this must lead to a lower BACT limit for H2 when the SCR control is taken into consideration. The commenter is incorrect.

Actual operating data from the best performing sources with SCR and other NO_x controls, that are carefully maintaining NO_x performance, indicate that an emission limit of 0.050 lb/MMBtu on a 30-day rolling average is appropriate, given the performance of these systems as a whole. Use of a lower NO_x outlet rate in conjunction with 90% removal of NO_x to arrive at a lower NO_x emission rate is not supported by the data. 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 for determining BACT.

If the comments about boiler outlet and achievable NO_x emission limits were correct, one would observe substantial periods of emissions of NO_x at a level at or below 0.015 lb/MMBtu. However, the data evaluated by Sunflower for the best performing sources show essentially no reported operational emissions at such levels.

See KDHE Response to Comment 5.

This suggests that the inference drawn by the commenter is, at best, purely theoretical and is unsupported by actual operating performance. As such, it cannot be the basis for a BACT determination.

Comment 78 (Dr. Sahu Comment C1.1 – cont'd):

Dr. Sahu indicates that the baseline NO_X emission rate used in the economic assessment of SCR at Table 4-11 of the BACT analysis is incorrect.

KDHE Response:

The baseline NO_X emission rate used in the economic evaluation of SCR options at Table 4-11 of the BACT analysis is a conservative estimate of the NO_X emission rate at the inlet to the SCR without LNB/OFA. This baseline emission rate was used to establish the cost effectiveness ($/ton of NO_X removed) of the SCR options evaluated in Table 4-11. Use of a lower baseline NO_X emission rate in the economic assessments, as suggested in the comment, would result in an increase in the cost per ton of NO_X removed.

Comment 79 (Dr. Sahu Comment C1.2):

There is no data from vendors provided with the H2 permit application to support these low SCR efficiencies or why higher SCR efficiencies cannot be obtained. Modern SCRs routinely achieve NO_x removal efficiencies greater than 90%. More than 30 units have achieved greater that 90% NO_x reduction based on 2005 data. 90% NO_x removal was achieved on 10,000 MW of coal fired generation in 2004. Many coal-fired units have been guaranteed to achieve greater than 90% NO_x reduction and are achieving greater than 90% reduction. H2's BACT analysis must demonstrate why the proposed SCR cannot achieve even a minimum of 90% NO_x reduction years from now when SCR retrofits on old subcritical boilers fired on PRB coals are doing better today. The application contains no site-specific or technical factors that would preclude SCRs from achieving at least 90% NO_x reduction, even with lower boiler out emissions in the range of 0.10-0.15 lb/MMBtu.

KDHE Response:

Actual operating data from the best performing sources with SCR and other NO_x controls, that are carefully maintaining NO_x performance, indicate that an emission limit of 0.050 lb/MMBtu on a 30-day rolling average is appropriate, given the performance of these systems as a whole. Use of a lower NO_x outlet rate in conjunction with 90% removal of NO_x to arrive at a lower NO_x emission rate is not supported by the data. For example, the comment that 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 for determining BACT.

If the comments about boiler outlet and achievable NO_x emission limits were correct, one would observe substantial periods of emissions of NO_x at a level at or below 0.015 lb/MMBtu. The data evaluated for the best performing sources show no reported operational emissions at such levels. This suggests that the inference drawn by the commenter is not supported by actual operating performance. As such, it cannot be the basis for a BACT determination.

Comment 80 (Dr. Sahu Comment C1.3):

Based on the discussions above, I believe that the NO_x BACT that is appropriate for H2 is 0.02 lb/MMBtu on a 30-day average basis, excluding startup and shutdown. Sunflower's support for its H2 BACT level is erroneous since it relies exclusively on a look-back analysis of actual operating data from existing units (none of which are subject to low permit limits and therefore have no incentive or compulsion to achieve good performance). The selected BACT level is also deficient because it uses the wrong BACT standard. The application does not evaluate, for example, why levels lower than 0.05 lb/MMBtu, are not BACT.

KDHE Response:

See KDHE Response to Comments 5, 76, 77, 78, and 79.

The commenter presents boiler NO_X emission rate data for various boilers not equipped with SCRs and implies that the H2 steam generator should have similar NO_X emission rates at the inlet to the SCR. It is inappropriate to compare boiler outlet NO_X levels at different facilities without carefully analyzing the CO and VOC emissions limitations of the other facilities, including the emission monitoring requirements. Also, wall-fired boilers tend to form more NO_X during combustion than tangential-fired boilers. The vast majority of the NO_X emissions data presented by the commenter are from tangential-fired boilers. These data do not adequately represent the potential range of NO_X emission rates from new PRB- fired boilers over a range of burner configurations, with CO and VOC emission limitations that represent BACT for H2.

The postulated BACT NO_X emissions limitation provided by the commenter is not technically feasible. Instead, the record shows that no NO_X emissions limitation lower than 0.050 lb/MMBtu is technically feasible as discussed above.
The NO_X BACT analysis was not based exclusively on the analysis of actual operating data from existing units. This was just one of the elements used to determine the NO_X BACT emissions limitation. The NOx BACT analysis included an evaluation of whether a lower NO_X emission limitation is technically feasible. It was determined that it was not. The data used in these assessments are based on the best performing facilities determined from NO_X CEMs data.

Comment 81 (Dr. Sahu Comment C1.4):

Even relying on the look-back approach to set BACT, the permit fails to set the correct BACT limit. Units achieved levels that were lower than 0.05 lb/MMBtu in 2007 and 2008.

KDHE Response:

Documentation was submitted to KDHE containing information to consider in determining the appropriate BACT emissions limitations for H2. The BACT analysis for H2 follows EPA's five step "top-down" BACT determination process, which is described in Section 1.3

of the BACT Analysis at Part 4.0 of the Application, as updated. The BACT determinations were conducted on a case-by-case basis taking into consideration, among other things, the achievability of an emissions limitation. Sunflower evaluated the latest proven technologies and compared H2 to similar facilities recently receiving permits and their emissions limitations. Many of the permit emissions limitations that were considered in the BACT review have yet to be demonstrated, because the plants have not started operations.

KDHE, as part of the permitting process require applicants to review technical literature regarding the current performance levels of air pollution control technologies. This information, as well as the detailed evaluation of recent emissions data from similar facilities were presented in Sunflower's BACT analyses, used to determine the BACT emissions limitations for each of the pollutants.

Comment 82 (Dr. Sahu Comment C1.5):

It is incorrect that there is a trade-off between lower NO_x and lower CO values. Newer low NO_x burners can achieve low NO_x as well as low CO values.

KDHE Response:

Relatively low combustion CO levels can be obtained while maintaining relatively low boiler NO_x emissions. However, it is well known that there is an inverse relationship between combustion NO_x and CO emissions; and the papers cited by the commenter do not demonstrate otherwise. As CO emissions are decreased, the resultant NO_x will increase since control of CO is dependent upon fuel blend, flame temperature, combustion residence time, oxygen in the combustion zone, fuel to air ratio, mixing, boiler and burner design, etc. Low CO and low NO_x are competing mechanisms and thus a balance must be chosen in the boiler design. 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 CO and VOC.

CO is a product of incomplete combustion (PIC). CO formation 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. 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 fuel and air during combustion. It is not possible to minimize these emissions without increases in emissions of NO_x.

CO and VOC are not specifically controlled by any post-combustion emission controls, though they are affected by the same combustion design consideration for NO_x. Impact to NO_x emissions is an appropriate environmental consideration (See Application Part 4.0, Section 7.1.2.1). As stated in the NSR Workshop Manual, at p. B.49, one environmental impact that could be examined is the trade-off between emissions of the various pollutants resulting from the application of a specific control technology.
NO_x emissions from coal-fired boilers are typically of greater concern to regulators then are CO and VOC emissions. Utilities account for roughly one quarter of all NO_x emitted in the US, and 90% of that comes from coal-fired boilers. CO emissions from utility boilers are a relatively small percentage of total U.S. combustion sources. The majority of 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.
NO_x is clearly of greater regulatory concern than CO and VOC and accordingly, NO_x control takes precedence over CO and VOC.

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 OFA) to achieve the greatest overall reduction. CO and VOC formation can be reduced only 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.

As noted above, there is no requirement that a BACT emissions limitation be the lowest established permit limit. The emissions limitations in the permit balances competing considerations that result in a project with the best available control technologies in the aggregate.

Comment 83 (Dr. Sahu Comment C1.6):

The averaging time for the proposed NO_x BACT limit of 0.05 lb/MMBtu (30-days) is not as stringent as the proposed NO_x limit for the Taylor Energy Center which had a proposed limit of 0.05 lb/MMBtu but on a 24-hour average or the Trimble County Unit 2 which also has a NO_x limit of 0.05 lb/MMBtu on a 24-hour average. Of course, as discussed earlier, Plant Washington (an almost identical unit) has a permit limit of 0.03 lb/MMBtu on an annual average basis. Arguably, these are more stringent limits.

KDHE Response:

For general information regarding NOx BACT limit, see KDHE Responses to Comments 76 and 77.

The Taylor Energy Center project was cancelled in 2007 before a final permit was issued. No conclusion can not be reached regarding BACT rates that the final permit would contain or the rates attainable at the plant.

The Trimble County Unit 2 NO_x emissions limitation is not based on a BACT determination, since the project netted out of PSD review for NO_x. Trimble's NO_x emissions limitation is expressed in terms of tons/day, not lb/MMBtu. The reference to 0.05 lb/MMBtu 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.

Regardless of the different opinions that have been expressed concerning Trimble County 2 and Taylor Energy Center, an evaluation of the best NO_x -performing units, including all 4 units at W.A. Parish, found that no unit has ever performed at 0.05 lb/MMBtu on a 24-hour basis.

Comment 84 (Dr. Sahu Comment C2):

The Proposed SO_2 Emission Limits are not BACT. Dr. Sahu asserts that the SO_2 limits are inadequate. The table below shows how the permit limit translates into control efficiencies, assuming the uncontrolled SO_2 values, also shown in the table below. The maximum efficiency expected of the SO_2 dry-scrubber proposed as the BACT control is 93.33%.

Table 6. Control Efficiencies for SO_2

Uncontrolled SO_2 (lb/MMBtu)	SO_2 Permit Limit (30 day average) (lb/MMBtu)	Calculated Control Efficiency of Scrubber
1.23	0.085	93.09%
0.9	0.085	90.56%
0.9	0.060	93.33%

KDHE Response:

See KDHE Response to Comments 63 and 64.

The removal efficiencies cited reflect the effect of dry scrubbers. However, SO2 control for H2 consists of both low sulfur fuel and the dry scrubber. Thus, to make a valid comparison, the effect of the low sulfur fuel must be taken into account. When the baseline is properly set to allow a proper comparison, the removal efficiency of the low sulfur coal and dry scrubber to be used by H2 taken together is equal to or greater than that of bituminous coal and a wet scrubber, and the resulting emissions limitation is comparable or more stringent.

Comment 84 (Dr. Sahu Comment C2) - cont'd

The Plant Washington permit was recently issued by Georgia EPD (April 8, 2010). The proposed Plant Washington unit is almost identical to H2. Among other limits for SO2, the

controlling permit requirement for Plant Washington is a requirement that it meet a minimum of 97.5% SO2 removal from the wet scrubber. Plant Washington's permit also requires that this control efficiency be maintained over a 30-day rolling average basis, using 2 SO2 CEMS, one located at the inlet and one at the outlet of the wet scrubber. The calculated permit limits for SO2 would be at H2, simply assuming that it meet the Plant Washington 97.5% removal efficiency. The limits range from 0.023 – 0.031 lb/MMBtu, depending on the uncontrolled SO2 value assumed.

KDHE Response:

The 30 day rolling SO2 emission limit for Plant Washington is 0.069 lb /MMBTU. Permit Condition 2.13.g. This is less stringent than the 0.060 lb/MMBTU 30 day limit for H2 SO2 emissions in the Holcomb 2 permit. The reason for the higher limit despite the commenter's claim of higher removal efficiency at Plant Washington stems from the authorized fuel there, i.e., PRB coal with up to a 50/50 blend of Illinois high sulfur bituminous coal, which has a higher sulfur content than PRB. The uncontrolled SO2 emission rate is 3.46 lb/MMBtu. The commenter does not offer a valid comparison, because he does not recognize the lower sulfur emissions attributable to using a "cleaner" lower sulfur coal. The comment fails to take into account the fact that the higher inlet sulfur concentration from the 50/50 blend coal at Plant Washington will result in faster reactions and a higher removal rate through the scrubber than the lower sulfur inlet concentration at H2. The net effect is a lower BACT emissions limitation for H2 and fewer emissions.

Comment 84 (Dr. Sahu Comment C2) – cont'd:

Plant Washington's permit contains separate SO_2 limits for annual, 24-hour and 3-hour averaging times, which H2's proposed permit does not. It is not clear how just having a 30-day rolling average limit will protect against violations of the 3-hour and 1-hour SO_2 NAAQS.

KDHE Response:

See KDHE Response to Comment 15.

Comment 85 (Dr. Sahu Comment C2.1):

Dry versus Wet Scrubber. A dry scrubber cannot achieve a removal efficiency of 97.5%. Therefore, the proper BACT control for SO_2 for H2 should be a wet scrubber.

KDHE Response:

Wet FGD historically has been applied to high sulfur coal projects. In some cases Wet FGD has been applied to low sulfur coals, but it has not achieved the same percentage reduction as high sulfur coal applications. That is because chemical reactions that remove SO_2 are faster if the SO_2 concentrations are higher. Although Wet FGD might achieve a slightly higher percentage SO_2 removal from the low sulfur coal to be used by H2 than Dry FGD

will, the difference is not significant. Based on energy, economic, environmental and other factors in addition to the level of control achievable by Wet FGD for low sulfur coal , Dry FGD is the best overall control technology for H2.

Comment 85 (Dr. Sahu Comment C2.1) – cont'd:

The SO_2 BACT analysis for H2 did not provide any technical details beyond some generic discussions of the various types of dry and wet scrubbers that are in the market today, it is true that a dry scrubber (of any design) will not be able to achieve anywhere close to the SO_2 removal efficiencies achievable by using any of the various wet scrubber designs. The fact that this central consideration (i.e., removal efficiency) was not given the proper weight makes the SO_2 BACT analysis and its conclusions wrong.

KDHE Response:

This statement is misleading because it does not take into account the low sulfur content of the PRB coal, which reduces the inlet concentration to the scrubber as well as the scrubber outlet concentration. There is an overlap in performance capabilities of Dry and Wet FGD, on low sulfur coal.

Comment 85 (Dr. Sahu Comment C2.1) – cont'd:

It is simply not true that the "vast majority" of units burning low sulfur PRB or other western coals, in general, use dry scrubbers rather than wet scrubbers. Even if the "vast majority" standard were applicable in a BACT determination, which it is not, I have provided a table below that refutes this non-factual statement entirely. Shown in the table are numerous units at various plants in many states that use any of several designs of wet scrubbers for SO_2 control. The fact is wet scrubbers have been and continue to be preferred for PRB units. As discussed above, a case in point is the Plant Washington unit.

KDHE Response:

The commenter identifies 80 plants, all of which burn PRB coal and are equipped with Wet FGD and therefore demonstrate that Wet FGD is the favored control technology to be installed on PRB-fueled plants. However, a review of the commenter's table, while referencing the CAMD database for SO_2 emission rates for calendar years 2007 through 2009, identifying the year of first service for the generating unit, and the first year that scrubber operation commenced, and other information generally available to interested parties, reveals otherwise.

Of the 80 facilities listed only 43 use PRB coal; 37 do not. Also contrary to the commenter's representation, only 55 are equipped with operating Wet FGD; four have Dry FGD; and 21

do not have FGD at all. Of the 37 units actually using PRB-south as a primary coal source, only 20 are equipped with operating Wet FGD; two have Dry FGD; and 15 have neither.

There are several factors that influence choices for FGD technology, as Sunflower clearly explained in its BACT analysis. Unit vintage and regulatory structure at the time of decision, geography and transportation availability, local mine availability and associated jobs, fuel sulfur content, water availability, and experience relating to the type of equipment to be operated are but a few of these factors.

Construction on 33 of the identified units was commenced before any NSPS requirements were enacted. Fuel switching opportunities and other, often complicated, factors guide utilities, usually in response to federal and state regulations or enforcement actions, and have sometimes resulted in scrubber retrofits on these units.

Construction on 40 — exactly half — of these units occurred under NSPS Subpart D requirements, when wet scrubbers or "compliance coal" was sufficient to meet emission limitations.[34] *Many of these initially operating Wet FGD on local coals — Dry FGD was not yet available — were later fuel-switched to PRB. Some equipped with a scrubber have, after fuel switching, continued to operate it; some have opted to cease operation of the scrubber. Indeed, some of the abandoned scrubbers are now being refurbished to meet new federal regulatory requirements.*

Additionally —

- *Many of the units identified as burning PRB coal obviously do not burn it, as can be distinguished by the annual average SO_2 emissions rates for PRB coals generally between 0.60 and 1.2 lb/MMBtu.*
- *Many of the units identified as being equipped with scrubbers obviously are not so equipped, again as can be distinguished by emission rates for PRB coals, as indicated by the previous bullet.*
- *Much of the coal burned in the plants sited in Arizona, New Mexico, Colorado, and western Wyoming do not burn PRB coal; rather they burn local fuels. Transportation, geography, and local fuels impact the equipment decisions in substantial ways. These fuels influenced early FGD technology decisions*[35] *which in turn influenced later decisions, especially in retrofit situations.*
- *Much of the coal initially burned in Texas was lignite, which is a higher sulfur low-rank fuel that for plants constructed after 1970 would have required a scrubber.*

[34] Note: Units on which construction commenced before September 1978 had to meet 1.2 lb/MMBtu emissions limitations. For higher sulfur fuels, this required flue-gas desulfurization; for PRB and certain other low-sulfur coals, no scrubber was required to meet this limitation. However, units with construction commencing after that date were subject to 40 CFR 60Da and thus were required to install scrubbers of a regardless of their SO_2 emissions. The Clean Air Act Amendments of 1977 also established the PSD program with its BACT analysis obligations.

[35] Wet FGD was developed earlier because much of the fuels used were from local high-sulfur mines. Many plants were actually located at the mine mouth.

These fuels influenced early FGD technology decisions, which in turn influenced later decisions, especially in retrofit situations.[36]

- *Much of the coal initially burned in Missouri and Kansas was higher-sulfur local coals. These fuels influenced early FGD technology decisions, which in turn influenced later decisions, especially in retrofit situations.*
- *Dry FGD became popular beginning in the mid-1970's as the Clean Air Act amendments required scrubbers even on those plants using low-sulfur coals. Dry FGD was, and is, a lower cost alternative when low-sulfur fuels are selected.*

Notably, the commenter does not include in his list 19 large electric utility PRB-fueled units that are equipped with Dry FGD, including: Holcomb 1 operated by Sunflower; Rawhide 1 operated by Platt River Power Authority;; Comanche 1, 2, and 3, and Pawnee 1 operated by Xcel Energy ; Springerville 1, 2, and 3 operated by TEP; Wyodak 1 and Wygen 1, 2, and 3 operated by Black Hill Resources, Walter Scott 3 and 4 operated by MidAmerican Energy; GRDA 2 operated by Grand River Dam Authority; Weston 4 operated by Wisconsin Public Service; Southwest 2 operated by City of Springfield, MO Municipal Utilities; and Hawthorn 5 operated by KCP&L. Further, there are 27 other units equipped with Dry FGD using other fuels, including 17 on bituminous coal, 5 on PRB-north, 4 on lignite, and one on waste coal; there are also 18 smaller units using various coals that are equipped with Dry FGD.

Of the 19 large units using PRB coal and otherwise comparable to H2 equipped with Dry FGD — but not identified by the commenter — eight were subject to BACT analysis requirements. All eight selected Dry FGD.

In summary, of the 14 units burning PRB coal that were developed after BACT requirements took effect, the score is Dry 8, Wet 6. Therefore, as a complete rigorous analysis demonstrates, none of the commenter's sweeping assertions are accurate.

Comment 85 (Dr. Sahu Comment C2.1) – cont'd:

The point about dry scrubbers being better at controlling other pollutants as compared to wet scrubbers cannot be answered in the abstract. Even if it were true, it cannot be a determinative factor for rejecting wet scrubbers for SO2 control. At best, this can be a consideration as part of the environmental aspect of the BACT analysis. But, the fact is the selection of the actual design of scrubber type, whether wet or dry, and how it is operated will determine to what extent other pollutants will be removed. It is not a law of nature or of physics that dry scrubbers, in all cases, regardless of design or operation, are always more effective in removing other pollutants such as acid gases, sulfuric acid mist, fine particulates, etc. as compared to any type of wet scrubber, regardless of its design or operation.

[36] Large unit-train shipments of PRB coal enabled large quantities of the low-sulfur "compliance coals" to be transshipped long distances.

KDHE Response:

The control of other pollutants using the dry scrubber was not the determinative factor in choosing the dry scrubber. It was a consideration as part of the BACT analysis, because the overall environmental impact is an important factor in that analysis.

Dry FGD performs better in controlling fine PM and SAM emissions than does a wet FGD. In the Wet FGD, the PM control equipment is located upstream from the Wet FGD absorber. Entrained scrubber slurry and fine SAM aerosols which escape the Wet FGD absorber's mist eliminator may contribute to increased PM emissions. In fact, Plant Washington will require sorbent injection to control fine PM, SAM, and other acid gases.

H2 would consume approximately 3 to 3.5% more fuel with a Wet FGD than with a Dry FGD system to achieve the same net electricity output.

A Wet FGD produces waste, primarily gypsum, which requires disposal. Although gypsum has useful applications in the construction sector, Holcomb Station's location away from this market makes the gypsum present in bottom ash and fly ash useless. Gypsum is also used in agricultural applications, however, Midwest soils have a high alkaline concentration and therefore gypsum is not useful in this region. Materials must be landfilled on site, as would any additional material generated by a Wet FGD.

A Dry FGD has no wastewater discharge, whereas a Wet FGD usually involves dewatering scrubber sludge and the wastewater being treated and discharged. This greater water use by a Wet FGD supports the use of a Dry FGD for H2. Holcomb Station has no existing wastewater treatment system. New evaporation lagoons or a wastewater discharge system would have to be permitted, installed, and operated on the site, raising additional economic and environmental issues.

All of these factors weighed in favor of the dry scrubber and, when coupled with the comparable levels of control actually achievable by both approaches, helped tip the balance in favor of Dry FGD as the best available control system for H2.

Comment 85 (Dr. Sahu Comment C2.1) – cont'd:

Third, as to water use, the factual record is simply incomplete. Of course wet scrubbers use more water than "dry" scrubbers. But what is the incremental water use? After all, dry scrubbers also use water. Typically, they use anywhere from 50-60% less water than wet scrubbers. But how is this material? After all, both H1 and H2 will use wet cooling towers for thermal control. Cooling towers require significant amount of make-up water. What is the expected make-up water requirement for the cooling towers? And, how does the incremental water use in a wet versus dry scrubber compare with the likely significantly greater make-up water required in the cooling tower? In fact, if water is such a scarce commodity, why are H1 and H2 not air cooled instead of being water cooled. Neither the application nor the KDHE review discusses these relevant technical factors. Thus, this factor, without any factual basis, cannot be used to reject wet scrubbers.

KDHE Response:

Water consumption was taken into account as one of the environmental factors considered in choosing Dry FGD over the Wet FGD. It was not the primary reason for rejecting the Wet FGD. The evaluation was holistic in approach, and all factors were considered.

Facilities strive to use the least water intensive methods reasonably available in day-to-day operations Dry cooling creates a significant parasitic load that would reduce plant efficiency. That increases the amount of coal that must be burned — and the amount of air pollutant emissions to generate the required electricity.

Comment 85 (Dr. Sahu Comment C2.1) – cont'd:

The issue of synergy, that is simply not a factor in the H2 BACT analysis. The fact that the existing unit uses a certain control technology cannot be the basis by which this same control technology becomes BACT for a new unit at the same plant –no matter how much synergy and how beneficial it is to the operator. If this were the case, existing, out-dated control technologies, would, in effect determine BACT. That would defeat the central purpose of a BACT analysis – which is to properly consider technology-forcing pollution controls at the optimum time, namely when a unit is to be newly constructed.

KDHE Response:

The fact that H1 uses Dry FGD was not the basis for the determination that the same control technology is BACT for H2. It was part of the entire analysis and identified as one of the advantages of implementing Dry FGD technology, specifically related to the cost analysis. Annualized cost for installing and operating a Wet FGD is approximately $4.3 million greater than a Dry FGD. There are existing supporting systems in place and operating reliably that can support the Dry FGD.

Comment 85 (Dr. Sahu Comment C2.1) – cont'd:

Top-controls that are cost-effective, as the wet scrubber definitely is in the present case, by Sunflower's own analysis, cannot be rejected simply based on high incremental costs.

KDHE Response:

Wet FGD was not rejected simply based on incremental costs. Economic considerations are appropriately weighed in the BACT analysis. Installing a Wet FGD is approximately $19.3 million more expensive than the installation of a Dry FGD, leading to an incremental control cost for Wet FGD relative to Dry FGD of $11,164 per ton removed.

See KDHE Responses to Comments 84, 86, and 87.

Comment 86 (Dr. Sahu Comment C2.2):

Scrubber Efficiency.
Wet scrubber can be designed to achieve 99% control of inlet SO2 or better. At a minimum better than 98% control for PRB coals is begin required today, much less many years from now , when H2 is likely to become operational. Athors from Advatech, a scrubber vendor and the Southern Company, note the following: "….A third Advatech scrubber installation is at Alabama Power's Plant Miller, which has four coal-fired boilers each with 660MW nameplate capacity. Four single-tower DCFS scrubbers have been constructed at this plant, three of which began operation in 2010 with the fourth scheduled for initial operation in 2011…" "[A]labama Power's Plant Miller has four 660MW nameplate capacity coal-fired boilers which primarily fire low-sulfur Powder River Basin (PRB) coal. Four single-tower DCFS scrubbers have been constructed and three of the scrubbers have already begun operation in 2010. Because of the lower sulfur concentration (0.4% S, 398ppm-d) in the coal fuel, a single tower DCFS was designed for 98% SO2 removal, and a self priming jet air sparger (JAS) system was applied as an oxidation device….."

***KDHE Response*:**

BACT emission limits are based on mass emission rates, not on the removal efficiency of the control device. The ultimate goal of BACT analysis is to require the applicant to install the best available technology based on the specific existing circumstances to assure emissions are as low as reasonably possible.

In reviewing the paper cited by the commenter, the coal that is used at the Alabama Power Plant Miller is a blend of subbituminous and eastern bituminous coal. There is a higher removal efficiency when the overall sulfur content is higher than when using western low sulfur coal. The paper does not mention what the heat based rate emissions are for the Miller plant, therefore, a comparison cannot be made between the Miller plant and H2. The paper cited by the commenter covers only a two day initial performance test conducted over February 1-3, 2010. The paper states that the PRB coal is 0.4% sulfur, yielding an FGD inlet sulfur concentration of 352 ppm and a Unit 3 initial performance result of 98.65% SO_2 removal. No emission levels (lb/MMBtu), heat input, or load factors are given. These test results are not a valid basis for setting BACT emissions limitations for H2, given the short duration and lack of information on operating conditions. Emissions limitations must be "achievable in practice," which means achievable under the worst foreseeable circumstances. Emissions limitations that are set must be achievable under the most adverse circumstances which can reasonably be expected to recur. More stringent emissions limitations can be rejected based on the absence of data showing that the more stringent rate has been consistently achieved over time.

Comment 86 (Dr. Sahu Comment C2.2) – cont'd:

SO2 levels below 0.02 lb/MMBtu are being achieved today. The Isogo Unit 1, a 600 MW supercritical unit in Japan, using a ReACT FGD has a permit limit of 0.02 lb/MMBtu. Actual data from the Pleasant Prairie Unit 1, a PRB unit with a wet scrubber shows that this unit has

been achieving SO2 levels of 0.019 or 0.020 lb/MMBtu consistently throughout 2008 and 2009 on a monthly and annual average basis. Since it is not constrained with such a limit, I believe that its performance can be further improved.

***KDHE Response*:**

The Isogo Unit 1 limit is 0.05 lb/MMBtu. The 0.02 lb/MMBtu limit is for Isogo Unit 2, which commenced commercial operation in July 2009. There is no reliable information to confirm if Unit 2 actually is achieving 0.02 lb/MMBtu. The document referenced in the comment does not state the sulfur content of the coal that is used at Isogo or the removal efficiency of the dry ReACT FGD. Therefore, it is impossible to compare either the Isogo Unit 1 or the Unit 2 SO_2 emissions rates achieved to H2.

With respect to Pleasant Prairie Unit 1, the emissions data was evaluated and calculated the mean 30-day rolling average to be 0.026 lb/MMBtu. Pleasant Prairie Unit 1, which has been operating for only a few years, has not yet experienced a scrubber operation disruption which could cause daily emission rates that correspond to uncontrolled emissions of SO_2. Such a disruption is anticipated over the life of a facility and could cause a significant increase in the 30-day rolling average using a Wet FGD, as illustrated by the experiences at other units.

Comment 86 (Dr. Sahu Comment C2.2) – cont'd:

Mitchell power station Unit 3 (Alleghany Power), a 292-MW generating unit near Pittsburgh, was retrofitted in 1982 with a magnesium enhanced lime ("MEL") wet FGD system pursuant to a Consent Decree. Data is available for four months during 1983 and 1984 for that unit. The daily average SO2 emission rate was 0.009 lbs/MMBtu and the daily average SO2 removal efficiency was 99.76%. The maximum monthly average during these four months was 0.029 lb/MMBtu, corresponding to a 99.72% SO2 reduction. Thus, over 99% reduction of SO2 was being achieved more than two decades ago.

***KDHE Response*:**

The unit referenced in the comment (Mitchell 3) is a 27 MW diesel fired unit and emissions from this unit are not comparable to H2.

Comment 86 (Dr. Sahu Comment C2.2) – cont'd:

A 2003 paper discussing the actual operating performance of the Chiyoda JBR or CT-121 wet scrubber technology in Japan notes that SO_2 removal efficiency of greater than 99% was achieved for all load levels and that a "[s]table SO_2 removal efficiency of over 99 percent" was achieved. Additionally, Chiyoda's experience list shows at least three instances of 99% removal.

***KDHE Response*:**

BACT emission limits are based on mass emission rates, not on the removal efficiency of the control device. The ultimate goal of BACT analysis is to require the applicant to install the best available technology based on the specific existing circumstances to assure emissions are as low as reasonably possible.

The inference drawn by the commenter from the data cited is unfounded. The vast majority of CT-121 wet scrubbers have not continuously achieved 99% removal efficiency. The, only two of the CT-121 units referenced achieved 99% removal efficiency. The other units listed by the Internet source had reported removal efficiencies that ranged from 82 to 98%.

As for the Shinko-Kobe site, the paper referenced to support the contention that 99% removal efficiency is achievable with the CT-121 is based on a facility that had been in operation for only one year in Japan. Such results have not been duplicated in the United States.

Comment 86 (Dr. Sahu Comment C2.2) – cont'd:

Mitsubishi Heavy Industries ("MHI"), another reputable vendor of wet scrubbers has a design called the High Efficiency Double Contact Flow Scrubber ("DCFS"), which has achieved SO_2 removal efficiencies as high as 99.9%. A presentation on the DCFS scrubber highlights the fact that it can be designed to achieve SO_2 removal efficiencies as high as 99.9% on a unit that burns high sulfur coals without the use of buffer additives. The manufacturer, MHI, guarantees SO_2 removal of 99.8%. A 2004 paper discussing the DCFS scrubber technology notes that this technology was recently selected at least two years ago by TVA for their Paradise Plant Unit 3, which will start up in early 2007. This paper also reports on several recent commercial operating successes with this technology "including super high desulfurization performance (i.e., 99.9%) with a single absorber." The paper also notes that the COSMO oil Yokkaichi unit is an outstanding example of high SO_2 removal by a single counter current DCFS. Commercial operation at COSMO began in 2003, and the FGD system has achieved a cumulative availability of 100% since startup. The system is designed at 99.5% and operates at 99.9% SO_2 removal efficiency.

***KDHE Response*:**

Please refer to earlier KDHE Response to Comment 86 (Sahu c2.2).

BACT emission limits are based on mass emission rates not on the removal efficiency of the control device. The ultimate goal of BACT analysis is to require the applicant to install the best available technology based on the specific existing circumstances to assure emissions are as low as reasonably possible.

The inference drawn by the commenter from the data cited is unfounded. First, the facilities referenced have petcoke and/or residue fire boilers, and not PC coal-fired boilers. Additionally, the reference provided indicate the first Greenfield DCFS system in the U.S. as being installed at the TVA Paradise Station Unit 3. Evaluation of DCFS performance at the TVA Paradise Station Unit 3 was included in the publicly-available Plant Washington air

permitting, showing removal efficiencies less than 99%, and an updated evaluation of TVA data available for calendar year 2008 yielded the same result.

Comment 86 (Dr. Sahu Comment C2.2) – cont'd:

A different variant of the wet scrubber technology –FLOWPAC – has demonstrated an SO_2 removal efficiency of over 99%. From November 2002 to March 2003, Karlshamn Unit 3 operated for 2152 continuous hours while firing a heavy fuel oil with an average sulfur content of 2.4%. The SO_2 emissions during this period were kept to 21 mg/Nm3, which is an SO2 efficiency of 99.5% with an S efficiency of 99%. During this period the FGD system was 100% available.

***KDHE Response*:**

BACT emission limits are based on mass emission rates not on the removal efficiency of the control device. The ultimate goal of BACT analysis is to require the applicant to install the best available technology based on the specific existing circumstances to assure emissions are as low as reasonably possible.

The commenter's reference for this technology indicates that the referenced unit is located in Sweden, and that the studies cited all focused on the use of oil and not coal. The FLOWPAC was designed to achieve 97.4% SO_2 removal when firing 3.5% sulfur fuel oil. Removal efficiency is higher on a high sulfur fossil fuel. While the Karlshamn unit achieved 99% during the testing as indicated in the comment, there is no indication that such a removal efficiency could be sustained long-term or that it would be achievable on a coal-fired unit.

Comment 86 (Dr. Sahu Comment C2.2) – cont'd:

Another vendor, Alstom, recently discussed high efficiency scrubbing on high sulfur fuels. As noted in the paper "[t]o date, the wet flue gas desulfurization system has achieved 100% availability while achieving the plant SO_2 emissions limits throughout the operating duration . . . as indicated . . . the WFGD system has achieved SO_2 removal efficiencies up to 99+% without the use of organic additives."

***KDHE Response*:**

BACT emission limits are based on mass emission rates not on the removal efficiency of the control device. The ultimate goal of BACT analysis is to require the applicant to install the best available technology based on the specific existing circumstances to assure emissions are as low as reasonably possible.

The Meliti Echalada Electric Steam Plant in Florina, Greece is equipped with a limestone based, Wet FGD system supplied by ALSTOM. The performance data for this plant show that, the SO_2 removal efficiencies varied from 94.9% to 99.2%. The data fail to indicate that the 99% SO_2 removal efficiencies have been achieved over the entire duration of the ALSTOM Wet FGD operation. The data also fail to provide evidence that the 99% reduction

would be applicable for all coals, since the evaluation involved a unit utilizing lignite coal with a sulfur content ranging from 0.4% to 2.7%.

Comment 86 (Dr. Sahu Comment C2.2) – cont'd:

The Coal Utilization Research Council within the Electric Power Research Institute (CURC/EPRI) concluded in its September 2006 Roadmap that up to 99% SO_2 removal for FGD was commercially available in 2005. The CURC/EPRI Roadmap also projects removals of up to 99.6% in 2010 and 99.9% in 2015.

***KDHE Response*:**

A table within the indicated reference shows a projected SO_2 removal rate of only 98-99% by 2025. While there is a table in the document indicating that SO_2 reduction in 2005 ranged from 90 to 99%, a later table indicates 90 to 95%. Nothing in the document indicated that 99+% was projected for the years 2010 and 2015.

Comment 87 (Dr. Sahu Comment C2.3):

H2's SO_2 BACT limit should not be any higher than 0.020 lb/MMBtu, on a 30-day average basis. The minimum wet scrubber efficiency should be 98% at all times, except startup and shutdown, and this should be measured using two SO_2 CEMS, one at the inlet and the other at the outlet/stack – similar to Plant Washington. The permit should also include appropriate SO_2 BACT limits for other averaging times, including 1-hour, 3-hour, 24-hour, and annual.

KDHE Response:

BACT emission limits are based on mass emission rates not on the removal efficiency of the control device. The ultimate goal of BACT analysis is to require the applicant to install the best available technology based on the specific existing circumstances to assure emissions are as low as reasonably possible.

Please refer to KDHE Response to Comments 85 and 86 (Sahu C2.1 and C2.2)..

As final support for the claim that wet scrubbers have been and continue to be preferred for SO_2 control, the commenter presents a table identifying approximately 90 units that purportedly burn PRB coal and have wet FGD systems. This claim is based on numerous inaccuracies. For example, the commenter's list includes lignite-fired units (two Oak Grove units) and nine units (Four Corners and San Juan) that burn coal from New Mexico. There are other examples of units where the commenter's claims are unfounded. For example, the four Colstrip units have venture scrubbers, which were primarily installed for PM control and are not true Wet FGD systems. Further, Plant Miller chose Wet FGD not because of PRB coal, which is burned there, but to have the ability to continue to be able to burn locally available Alabama coal, which has higher sulfur content

In summary, the commenter's contentions that Wet FGD rather than Dry FGD is BACT SO_2 control technology, that the permit must include a sulfur reduction efficiency requirement, and that the BACT emissions limitations for SO2 should be lowered all are without merit.

Comment 88 (Dr. Sahu Comment C3):

The proposed limit of 0.0037 lb/MMBtu on a three-hour average basis does not represent BACT for H2SO4. The BACT analysis fails to carefully consider several options to minimize H2SO4 emissions. The entire record fails to demonstrate how the limit is the best achievable. Design and operational details of this pollution control train should have been discussed in the application. There is no demonstration that the emission limit based on the maximum degree of reduction has been selected. The application notes there are other facilities have limits lower than 0.004 lb/MMBtu but contains no reasoned explanation is offered for why H2 cannot meet these lower limits. The application also provides stack test data, including those collected at H1 in 2004 – indicating that lower levels of SAM are possible and measurable using proper (i.e., properly conducted EPA Method 8A or the Controlled Condensate Method). So, its concerns relating to measuring SAM are unfounded. In short, there is simply no basis proposed BACT emission rate for SAM. The expected SO_3 and SAM emission from this PRB-fired unit are likely to be inherently low, and assuming low conversion SCR catalysts as well as a pollution control train consisting of sorbent injection, baghouse, and wet FGD, a BACT limit of 0.0010 lb/MMBtu is recommended for SAM.

KDHE Response:

The commenter focuses on removal results from limited studies around individual components (e.g., air heaters and baghouses) and makes assumptions that removal results are simply additive. The commenter presented no data to support his analysis.

Section 4 of the Application, as updated, contains a BACT analysis for SAM. Sunflower considered a Dry FGD and fabric filter, Wet FGD and ESP, or fabric filter and Wet ESP 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 systems are not used because the expected inlet SO_3 levels into the Wet ESP in this configuration would be so low that little removal would take place.

The commenter suggests that emissions of SAM might be reduced by use of a lower conversion SCR catalyst. Constraining the SO_2 to SO_3 oxidation rate of the SCR catalyst can also affect the activity of the catalyst for NO_X reduction. The NO_X emissions limitation for H2 is based on the maximum degree of reduction of NO_X for the combination of low NO_X burners with OFA plus SCR. Sunflower will utilize low SO_2 to SO_3 conversion rate SCR catalyst, consistent with the catalyst formulation requirements for meeting the NO_X emissions limitation. The imposition of an additional restriction on the SO_2 to SO_3 conversion rate in selection of the SCR catalyst is not demonstrated technology.

The commenter cites the SAM emissions limitations in recent permits that are below the H2 0.0037 lb/MMBtu emissions limitation, including facilities identified in Table 4-31 of the Sunflower BACT analysis. The cited permits do not define for BACT for H2.

The State of Texas has not relied on the Parish 8 emission limits in determining more recent SAM BACT emission rates for the 8 TXU units (0.0037 lb/MMBtu); the Spruce unit (0.0037) built by the City of San Antonio; Sandy Creek unit (0.0037) built by LS Power. Santee Cooper Cross Units 3 and 4 netted out of PSD for SAM along with NO_X and SO_2. Santee Cooper Cross Units 3 and 4 were not required to conduct a BACT analysis for SAM. Santee Cooper has proposed two similar units (Pee Dee Units 1 and 2) which initially proposed a substantially higher limit of 0.0075 lb/MMBtu as BACT for SAM.

The BACT analysis evaluates the BACT emissions limitations for recently permitted PC-fired boilers, including projects using similar fuels and similar air quality control system configurations. Sunflower considered recent SAM stack test reports, including projects using similar fuels and similar air quality control system configurations, in its determination of the BACT emissions limitations for SAM. The variability in the observed test results, even for facilities with similar designs and fuel supplies, and the need to maintain a compliance margin in emissions limitations militate against a lower SAM BACT emissions limitation for H2.

The commenter proposes a BACT emissions limitation for H2 of 0.001 lb/MMBtu. The commenter neither provides details of the basis for this proposed limitation nor cites any operating data that show consistent compliance with such a proposed SAM emissions limitation.

Sunflower conducted a proper BACT analysis for SAM that eliminated alternative control options and determined a BACT emissions limitation based on both limitations established as BACT elsewhere and an analysis of SAM stack test results from similarly configured facilities using similar coal supplies. KDHE concurs with the permit BACT emissions limitation for SAM of 0.0037 lb/MMBtu.

Comment 89 (Dr. Sahu Comment C4):

The Proposed PM/PM_{10} Emission Limits Are Not BACT. These limits may be "consistent" with $PM/PM_{10}/PM_{2.5}$ limits for other facilities, but do not appear to have been set considering what is achievable using current baghouse technology. The outlet concentration depends more on the design of the fabric filter, the choice of filter materials, and the manner of operation and maintenance of the filters. Yet, the application or the record does not contain any detailed technical discussion of any of these aspects. the filterable $PM/PM_{10}/PM_{2.5}$ limit(s) should be reassessed and based on the actual capabilities of the best types of coated bag filter available. At a minimum, the limit(s) should take into account the numerous low test data results that are provided and other similar data that are available from other states. The total $PM/PM_{10}/PM_{2.5}$ limit(s), which includes the condensable (which will all likely be $PM_{2.5}$ in size or smaller) should be reassessed as well to realistically reflect the BACT degree of control of the major condensables, namely H_2SO_4 and certain VOCs. It can be no greater

than 0.010 lb/MMBtu, on a 24-hour average basis. The total PM/PM10 limits should be no greater than the proposed 0.018 lb/MMBtu, but on a 24-hour average basis (and without the likelihood that they may be relaxed to 0.025 lb/MMBtu, as proposed). The total $PM_{2.5}$ limit should also be much lower.

KDHE Response:

The Florida test data cited did not include information necessary to assess the validity and representativeness of the data, including control equipment type, fuel type, process information, or quality control procedures used during the testing. Almost 30% of the emission rates were greater than the filterable PM (PM, filterable PM_{10} and filterable $PM_{2.5}$) emissions limitations in the permit, i.e., 0.012 lb/MMBtu on a 30-day rolling average basis. There is significant variability in the Sahu referenced tested PM/PM_{10} in power plants as a result of the EPA test method measurement of condensables. The test method has not, historically measured condensable particulate matter accurately nor consistently.

KDHE has determined that fabric filters were chosen because they are the technology that can achieve the highest degree of control of filterable PM emissions. The cited data suggest that in order to meet the limitations in the permit, a high level of performance will be required from these fabric filters. All of those higher rates relied upon by the commenter would be violations of the Sunflower permit limitations. The filterable PM limitation in the permit is consistent with these results, including consideration of the need to establish emissions limitations that can be consistently attained.

Sunflower conducted a proper BACT analysis for filterable PM and total PM10/PM2.5 that eliminated alternative control options and determined a BACT emissions limitation based on both limitations established as BACT elsewhere and an analysis of stack test results from similarly configured facilities using similar coal supplies. KDHE concurs with the permit BACT emissions limitation for filterable PM/PM10/PM2.5 of 0.012 lb/MM Btu and total PM10/PM2.5 of 0.018 with a contingency limit of 0.025 lb/MMBtu.

Comment 89 (Dr. Sahu C.4) – cont'd:

The total PM/PM10/PM2.5 limit(s), which includes the condensable (which will all likely be PM2.5 in size or smaller) should be reassessed as well to realistically reflect the BACT degree of control of the major condensables, namely H2SO4 and certain VOCs.

KDHE Response:

There is no justification for the duplicative analysis.
It has been demonstrated in the control technology analysis section of the permit application that the H_2SO_4 and VOC ("major condensable") emissions limitations are BACT. There is no need to reassess the total $PM/PM_{10}/PM_{2.5}$ emissions limitation in the permit. The Application discusses in detail at Part 4, Section 5.2.1.3 and Appendix K the uncertainties associated with addressing condensable particulate matter, given that the available

measurement techniques are still under close scrutiny. The test method has not, historically measured condensable particulate matter accurately and consistently.

Comment 89 (Dr. Sahu C.4) – cont'd:

The permit limit for filterable PM/PM10/PM2.5 for Plant Washington is 0.010 lb/MMBtu on a 24-hour average basis, to be monitored using CEMS. In addition, the total PM/PM10 limit is 0.018 lb/MMBtu, on a 24-hour average basis and the total PM2.5 limit is 0.0123 lb/MMBtu on a 3-hr average basis.

KDHE Response:

Plant Washington is not operating, so there are no data indicating that permit levels are in fact achievable over the life of the plant.

As noted above, almost 30% of the measured filterable emission rates cited by the commenter from the Florida test data are greater than the filterable PM/PM_{10}/$PM_{2.5}$ emissions limitation of 0.012 lb/MMBtu in the permit. Imposition of a more restrictive 24-hour average for the filterable PM/PM_{10}/$PM_{2.5}$ limitation is not warranted.

Given the uncertainty surrounding the accurate measurement of condensable particulate matter, using a 0.018 lb/MMBtu, 24-hour average for the total PM_{10}/$PM_{2.5}$ emission limitation is similarly unwarranted.

Due to the limited test data and the uncertainties associated with the EPA-required condensable particulate matter test method, a consistent total PM_{10} emissions rate for H2 of 0.018 lb/MMBtu may not be achievable. A contingency limitation of 0.025 lb/MMBtu is prudent. The difference in the two values and the compliance requirements established in the permit direct the result of these uncertainties. If the initial performance test does not indicate that the emissions limitation of 0.018 lb/MMBtu is consistently achievable, then either the emissions limitation indicated by the initial performance test, contingent upon approval by KDHE, will be incorporated into a revised permit, or additional testing will be conducted.

Comment 90 (Dr. Sahu Comment C5):

The applicant's and KDHE's BACT analysis for $PM_{2.5}$ is significantly flawed. Rather than conduct an independent BACT analysis for filterable $PM_{2.5}$, the company and KDHE simply relied on the BACT analysis for filterable PM_{10}. As I have shown above, there were several $PM_{2.5}$ controls that the applicant and KDHE failed to fully evaluate. Further, the proposed total $PM_{2.5}$ BACT limit is based on BACT determinations for VOCs, H_2SO_4, SO_2, and NO_x which are also flawed as discussed in these comments. Thus, the proposed emission limits both the filterable and total $PM_{2.5}$ fractions fail to reflect BACT and must be re-analyzed.

KDHE Response:

KDHE believes the BACT analysis was performed in compliance with all applicable Requirements.

Comment 90 (Dr. Sahu Comment C5 – cont'd):

At page 36 of his report, Dr. Sahu indicates that KDHE's proposed emission limitation for H_2SO_4 and VOC fail to reflect BACT and, therefore, the total $PM_{2.5}$ limit fails to reflect BACT.

KDHE Response:

In the control technology analysis section of the Application, H_2SO_4 and VOC emissions limitations are BACT. There is no need to reassess the total $PM_{2.5}$ emissions limitation.
See KDHE Response to Comment 90.

Comment 90 (Dr. Sahu Comment C5) – cont'd:

At page 36 of his report, Dr. Sahu states; "The media Ryton, for example, is commonly used in similar applications for PM control. This media removes 99.9% of larger particles, but operates at far lower efficiencies for the smaller particles. Thus, other media must be considered in a $PM_{2.5}$ BACT analysis."

KDHE Response:

Sunflower has not selected the filter media that will be used for the H2 filter bags. Filter media selection for the H2 filter bags will be determined during the detailed design stage of the project. Filter media mentioned by the commenter, as well as other filter media, will be considered for the H2 filter bags. The ultimate filter media selection will consider the latest technological developments at the time of decision and will address factors such as filterable $PM_{2.5}$ and condensable $PM_{2.5}$ removal efficiencies, pressure drop, bag life, compatibility with flue gas chemistry and temperatures, and effectiveness with potential mercury sorbents such as activated carbon.

Citations used by the commenter to characterize the collection efficiency of various filter media are based on lab tests. While these data are useful, they cannot be considered representative of full scale power plant operations, and long-term field testing is required to properly characterize emissions. To date, there are very little filterable $PM_{2.5}$ particle size field data publicly available.

Filterable $PM_{2.5}$ emission rates are not totally dependent on the type of filter media (bags). There are other factors within the fabric filter control system that influence the level of

filterable $PM_{2.5}$ emissions (e.g., air to cloth ratio, bag cleaning frequency and intensity, bag life, and QA/QC during bag fabrication and installation). An analysis of all the relevant applicable options will be performed before the design and type of filter is determined.

Comment 90 (Dr. Sahu Comment C5) – cont'd:

At page 37 of his report, Dr. Sahu states that the size distribution of filterable $PM_{2.5}$ emissions will be different for different types of bags. Therefore, the applicant should have obtained the particle size distribution data and the baghouse outlet emission rates from baghouse vendors for the various types of bags available in order to characterize filterable $PM_{2.5}$ BACT emissions for H2. EPA bag testing data is referenced in Footnote 78.

KDHE Response:

See KDHE Response to Immediate Preceding Comment.

Babcock & Wilcox and Kansas City Power & Light (KCP&L) examined the impact on emissions and operating conditions due to a change in fabric filter media at KCP&L's Hawthorn Unit 5 after 3.5 years of operation with the original equipment manufacturer (OEM)-supplied filter bags. The replacement filter media was a membrane over polyphenylene sulfide (PPS), which is noted for low filterable PM emissions. The new media resulted in significantly lower filterable PM emissions than the initial OEM needle felt filter media, but significantly higher condensable PM emissions were observed. The net result of the filter media change has been a fairly consistent level of total PM emissions. This field test of various filter media demonstrates the need to carefully assess filter media under actual power plant operating conditions, rather than solely relying on laboratory test data measuring only filterable PM2.5 collection efficiency.

Comment 90 (Dr. Sahu Comment C5) – cont'd:

At page 37 of his report, Dr. Sahu states that the applicant should have evaluated the various types of bags available in its top-down BACT analysis for PM2.5. He also indicated that a bag leak detection system should also be considered as part of the BACT determination.

KDHE Response:

See KDHE Response to Immediate Preceding Comment H2 will use a CEM system for direct measurement of filterable PM. The use of a bag leak detection system is not necessary for compliance monitoring. A final design for the fabric filter system will include a bag leak detection system in order to assist in operation and maintenance of the fabric filter system.

Comment 90 (Dr. Sahu Comment C5) – cont'd

At page 37 of his report, Dr. Sahu states that a wet ESP placed after a fabric filter would eliminate significant amounts of $PM_{2.5}$ emissions and that the applicant failed to evaluate this combination of controls.

KDHE Response:

This comment represents a purely theoretical assessment of additional $PM_{2.5}$ control. A Wet ESP has never been installed in this type of configuration.

Sunflower did evaluate the cost-effectiveness of installation of a Wet ESP downstream of a Dry FGD/fabric filter system. The cost-effectiveness of this application of a Wet ESP would exceed $66,000/ton of $PM_{2.5}$ removed. (See Part 4 Section 6.1.4.1 of the BACT analysis in the Application, as updated).

Comment 90 (Dr. Sahu Comment C5) – cont'd

At page 38 of his report, Dr. Sahu states that the applicant did not properly consider the Advanced Hybrid Particulate Collector (AHPC).

KDHE Response:

Sunflower initially considered electrostatic fabric filters. See page 4 of 7 of Appendix E of the Application, as updated. Sunflower eliminated this technology from further consideration at H2 due to unacceptable performance at full-scale demonstration. The experience with this technology at Otter Tail Power's Big Stone plant in South Dakota, referenced by the commenter, is summarized in Appendix E. A number of problems were encountered during the DOE-sponsored test program; and the plant owner replaced the system with a conventional pulse jet fabric filter at the end of the program.

Comment 90 (Dr. Sahu Comment C5) – cont'd

At page 39 of his report, Dr. Sahu states that neither Sunflower nor KDHE fully evaluated (1) Compact Hybrid Particulate Collector (COHPAC), (2) Indigo Particle Agglomerator, (3) Wet ESP, and (4) Wet Membrane ESP.

KDHE Response:

An evaluation of Wet ESP technology as described in Comment 86 (Sahu C.2.2) above. *Sunflower initially considered the Indigo Particle Agglomerator. As described in Appendix E to Sunflower's Application, as updated, this technology option was eliminated from further consideration because the technology has only been applied upstream of Dry ESPs and has not been demonstrated in combination with fabric filters.*

COHPAC is a technology that has been applied only downstream of ESPs as a polishing device for underperforming ESPs. There have been no applications of COHPAC downstream of fabric filter systems as will be used for H2.

Wet Membrane ESP is simply a variant of Wet ESP technology. Conventional Wet ESP technology for utility boiler application utilizes metal collecting electrodes, whereas Wet Membrane ESP technology utilizes fabric membranes as a replacement for the metal

collecting electrodes. The technical reference concerning Wet Membrane ESP technology that was cited by Dr. Dean, see KDHE Response to Comment 196 (Dean 6), compared the performance of a membrane design to a conventional metal tube design at a small pilot-scale slip-stream from a coal-fired unit. Under test conditions the membrane design performed somewhat better than the metal tube design. This technology is not demonstrated on large-scale facilities using coal as a fuel. Thus, there is insufficient engineering information available to enable the thorough evaluation of this control technology required to determine whether it is feasible and whether its performance is consistently predictable.

Comment 90 (Dr. Sahu Comment C5) – cont'd

At page 39 of his report, Dr. Sahu summarizes that the PM2.5 BACT is flawed because Sunflower and KDHE failed to fully evaluate certain technologies and due to flawed BACT determinations for VOCs, H2SO4, SO2, and NOX.

KDHE Response:

The commenter's conclusion is not well-taken, for the reasons discussed in responses to the comments regarding the BACT determinations for $PM_{2.5}$, VOCs, H_2SO_4, SO_2, and NO_X.

Comment 91 (Dr. Sahu Comment C6):

The proposed CO and VOC emission limits are Not BACT. There is no trade-off regarding NO_x and CO or VOC emissions from the boiler, much less at the stack, with the opportunity for further NO_x reduction at the SCR. The CO limit proposed is not BACT because there are several other units with limits that are lower. BACT for CO should be no less stringent than 0.10 lb/MMBtu measured on a 30- day average basis or even 24-hour average basis – with compliance to be demonstrated using CO CEMS. The VOC BACT limit should be expressed with the correct number of significant digits and .should be no greater than 0.0024 lb/MMBtu on a 3-hour average basis, with compliance to be demonstrated using a stack test.

KDHE Response:

The statement referring to the trade-off between NO_X emissions and CO/VOC emissions is not accurate. The commenter has separated the pollutants to advocate his position. Such an approach does not recognize the physical and chemical realities of the combustion process.

As discussed in Part 4.0, Sections 3.1.1.1, 7.1.1.1, 7.1.2.1, 7.2.1, 8.1.1.1, 8.1.2.1 and 8.2.1 of Sunflower's Application, as updated, a trade-off does exist between NO_X emissions and CO/VOC emissions. This is discussed in Part 4.0 of the Application, as updated, which includes a table (Table 4-25, page 4-107 and Table 4-29, page 4-121) that limits in other permits reflect this tradeoff.

Combustion is a complex process, the steam generator designer has to design the combustion process to control the CO and VOC emissions. As these emissions are decreased, the resultant NO_X will increase since control of VOC and CO are dependent upon fuel blend,

flame temperature, combustion residence time, oxygen in the combustion zone, fuel to air ratio, mixing, steam generator and burner design, etc. Low CO and VOC and low NO_X are competing mechanisms and thus a balance must be chosen in the design.

Steam generators 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. Instead NO_X, CO, and VOC are dependent variables and therefore are affected simultaneously. The contents of the tables referenced above are replicated below in Table 7 to illustrate that while plants referenced by the commenter may have lower CO or VOC limits, these same facilities generally have higher NO_X limits. Specifically, Intermountain Power and Thoroughbred NO_X limits are 0.07 lb/MMBtu and Santee Cooper Cross is 0.08 lb/MMBtu, both higher than the 0.05 1b/MMBtu emissions limitation in the Holcomb 2 permit.

Only the Desert Rock and Plant Washington permits include limits that are relatively low for all three pollutants. These plants have not been constructed and thus are of lesser value in this analysis than a facility that has been in operation.

Sunflower has inquired of a potential EPC contractor regarding whether the Plant Washington limits may be guaranteed as a package, with the following responses:

- *NO_X at 0.05 lb/MMBtu can be guaranteed.*

- *CO at 0.12 lb/MMBtu may be guaranteed, based on the demonstrated capability of burner hardware and controls to meet this 30-day average; but a limit lower than 0.12 lb/MMBtu may require exclusion or limitation of startups, shutdowns, and load changes (pulverizer in/out of service) and may require commercially unproven equipment and controls.*

- *VOC at 0.003 lb/MMBtu would be guaranteed, but not a lower limit.*

The Desert Rock permit was remanded, so there has been no demonstration that the permit's emissions limitations are achievable.

Table 7 is shown on the following page.

Table 7. Comparison of Permit Limits Issued for Coal

Coal Plant	NOx Limit lb/MMBtu	CO Limit lb/MMBtu	VOC Limit lb/MMBtu	Status of Plant	Coal Type and Plant Size
Santee Cooper Cross Units	0.07	0.15 (30-day)	0.0024 (3-hr)	Operating	Bit + petcoke/ PC/ 660 MW each (2)
Intermountain Power Unit 3	0.07	0.15	0.0027 (3-hr)	Permit Oct 2004	Bit or blend Bit & Sub bit / PC / 950 MW
Big Cajun II, Unit 4	0.07	0.135 (30-day)	0.0034	Permit Dec 2008	Bit or PRB / PC / 675 MW
Comanche Unit 3	0.080	0.13 (8-hr rolling)	0.0035	Permit Jul 2005	PRB/ SCPC / 750 MW
Oak Creek / Elm Road	0.07	0.12 (24-hr)	0.0035 (24-hour)	Permit Jan 2004	Bit / SCPC / 615 MW each (2)
Prairie State	0.07	0.12 (24-hr block)	0.004 (3-hr block)	Permit Jan 2005	Illinois #6 / PC / 750 MW each (2)
Dallman Unit 4 City of Springfield	0.05 0.06 (w/ SSM)	0.12 (3-hr block)	0.0036 (3-hr block)	Operating	Bit / PC / 250 MW
Duke Cliffside	0.07	0.12	0.003	Permit Mar 2009	Bit / SCPC / 800 MW
Longview Power	0.07	0.11 (3-hr rolling)	0.004 (3-hr rolling)	Permit Mar 2004	Bit / SCPC / 750 MW
Thoroughbred Generating Station	0.07	0.10 (30-day rolling)	0.0072 (30-day)	Permit May 2006	Bit / PC / 750 MW each (2)
Desert Rock	0.06 (24-hr block) 0.05 (30-day)	0.10 (24-hr block)	0.003 (3-hr)	Permit Jul 2008	Western Bit/ SCPC / 750 MW each (2)
Trimble Co Unit 2	Net out	0.10 (30-day rolling)	0.0032 (3-hr rolling)	Permit Feb 2008	Bit / SCPC / 750 MW
Plant Washington	0.05	0.10	0.0024	Permit April 2010	Bit. + petcoke / PC/ 850 MW

Sunflower approached the determination of BACT emissions limitations for these three pollutants in a comprehensive fashion, recognizing the interrelationships in the formation, relative level of concern, and impact of each. 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 determining BACT emissions limitations.

It is inappropriate to simply look at one pollutant at any particular facility without considering the emissions limitations of other pollutants. The emissions limitations contained in these recent permits and the holistic approach to evaluating NO_X, CO, and VOC, demonstrate that the H2 emissions limitations of 0.12 lb/MMBtu for CO and 0.003 lb/MMBtu for VOC are BACT.

Comment 92 (Dr. Sahu Comment C7):

The permit should specify the minimum injection rate to achieve a minimum of 90% removal of mercury from what is expected in the coal. There is simply no reason the mercury emission rate should be any greater than the Plant Washington mercury emission rate. Test results provided show irrefutable evidence that lower mercury emission rates than H2's proposed 0.02 lb/GWh mercury limit have been achieved in practice, including as measured by CEMs and on a long term basis. Consequently, H2's proposed mercury limit is unsupportable.

KDHE Response:

See KDHE Responses to Comments G, 52 and 53. Mercury emissions will be limited by state-only conditions in the Holcomb 2 permit.

Mercury test data for H1 are relevant because H2 will be very similar to H1 in design and operation. The performance level in the permit is based upon actual reductions in mercury concentration demonstrated at H1 and then extrapolated for highest mean coal mercury concentration.

The permit H2 mercury emissions limitation of 0.020 lb/GWh corresponds to a control efficiency that is better than all but one of the percent reduction levels listed in Table 2 of the commenter's report. This emissions limitation also corresponds to the lowest of the mercury emissions limitations promulgated by EPA for all fuels in its (now vacated) mercury NSPS standard. Under these circumstances, there is no basis for any mercury removal efficiency as a permit requirement.

Comment 93 (Dr. Sahu Comment D1):

IGCC should be selected as BACT. IGCC is far superior in controlling emissions of NO_X, SO_2, and several other harmful pollutants than the supercritical technology proposed, except for VOC emissions. Environmentally, IGCC is clearly a better choice, producing less

mercury, among other emissions, and solid waste, and using less water. The overall superiority of IGCC technology in plant efficiency, controlling SO_2, NO_X, and PM, as well as other toxic chemicals together with other environmental benefits clearly justifies the selection of IGCC technology over the supercritical PC technology proposed for H2.

KDHE Response:

Please refer to Response to KDHE Comment 39 (Sierra Club VI A).

Comment 94 (Dr. Sahu Comment D2):

If for some reason IGCC is not selected as BACT, then clearly USPC should be selected as BACT. As explained in the report of Bill Powers, USPC is available technology that should have been considered for H2. The BACT analysis must be redone to include both IGCC and USPC, and the public must be given an opportunity to comment on the new BACT analysis.

KDHE Response:

Please refer to KDHE Response to Comment 1 (EPA 1).

Comment 95 (Dr. Sahu Comment D2) :

H2 is a Major Source of HAP Emissions. It is Subject to the Case-by-Case MACT determination provisions. KDHE has failed to propose MACT limits for Sunflower H2.

KDHE Response:

Please refer to KDHE Responses to Comments G, 52, and 53.

D. COMMENTS FROM MR. BILL POWERS, P.E., SUBMITTED ON BEHALF OF EARTHJUSTICE (Comments 96-105)

Comment 96 (Mr. Powers Comment II):

Tri-State/Sunflower have obligation under CAA to consider any process that converts coal to electric power in a BACT evaluation. Any process that is capable of converting PRB coal to electric power must be considered in the BACT evaluation.

KDHE Response:

Please refer to KDHE Response to Comment 39 (SC VI.A).

The objectives of the Expansion Project are identified in Part 1.0 of the permit application. The selection of an SCPC-fired steam generator as its basic generation technology is not a

BACT issue. It is an issue of defining the source to be permitted in this first instance. Definition of the source is the responsibility of the applicant.

Comment 97 (Mr. Powers Comment III):

Tri-State/Sunflower can be required by the KDHE to include Natural Gas Combined Cycle in the scope of the BACT evaluation.

KDHE Response:

Please refer to KDHE Response to Comment 39 (SC VI.A).

KDHE does not have this authority. It is Sunflower's responsibility to evaluate alternatives to make a reasoned determination of the lowest cost of energy for its consumers.

Comment 98 (Mr. Powers Comment IV):

Black & Veatch (B&V) Analysis of Alternatives is flawed for failure to consider the CO_2 reduction benefits of Ultra-Supercritical PC or the cost advantages of IGCC when CO_2 capture is necessary

KDHE Response:

Please refer to KDHE Response to General Comment 39 (SC VI.A).
At this time, KDHE does not have regulations in place limiting CO_2 emissions. Nor do federal regulations currently require BACT limits on CO_2 emissions. KDHE must administer the Kansas air permit program based on currently applicable rules and regulations. Sunflower's Application is in compliance with and satisfies all applicable existing environmental laws and regulations.

As CO_2 emissions reductions are not required for H2 under existing law, there was no reason for Black & Veatch to consider that subject.

Comment 99 (Mr. Powers Comment V):

B&V consciously excluded USPC Technology, and detailed analysis of the appropriate IGCC Technology for CO_2 capture, from Holcomb Studies.

KDHE Response:

Please refer to Comments 1, 37, 39, 96 and 98. Since CO_2 capture is not a requirement. for H2, therefore, would not be a requirement for its consultant to undertake this analysis.

Comment 100 (Mr. Powers Comment VI) :

Failure to include USPC Technology undermines B&V August 2006 and June 2010

studies and basis for selecting SCPC for Holcomb. The Turk plant already under construction is USPC.

KDHE Response:

Please refer to KDHE Response to Comment 1. Sunflower has stated it is aware of Mr. Duellman's testimony for AEP in the Turk "Hempstead County proceeding" and acknowledges improvements in efficiencies that may someday be consistently achievable with USPC technology. AEP is the largest coal-based generating fleet in the United States and has many times in the past taken the lead in advancing generation and transmission technologies. AEP has often been successful in its endeavor; sometimes not.[37]

Sunflower has indicated, the small not-for-profit cooperatives involved in Expansion Project *cannot assume comparable responsibility for uncertain reliabilities that arise from being the pioneers to advance USPC technology in the United States. As discussed in Comment 1, recent problems plaguing the Comanche 3 and Iatan 2 generating units confirm Sunflower's evaluation relating to reliability as a primary basis for the technology it has selected.*

Comment 101 (Mr. Powers Comment VII) :

Failure to consider SCPC and IGCC with CO_2 capture prevents informed decision making by KDHE. B&V provides no basis in the June 2010 study for the capital cost differential between IGCC and SCPC increasing from 20 percent in the August 2006 study to 70 percent in the June 2010 study. B&V's justifications for rejecting IGCC do not hold up under close scrutiny. B&V relies on analysis of first generation IGCC demonstration projects to assert lower reliability for IGCC technology. Numerous second generation IGCC plants have been built since approximately 2000 that incorporate the lessons learned from the first generation projects to assure high reliability.

KDHE Response:

Please refer to Comments 37, 39, and 98. Since CO_2 capture is not required for H2, consideration of that subject at the expense of Kansas taxpayers is not necessary to KDHE's informed decision on Sunflower's Application

Comment 102 (Mr. Powers Comment VIII) :

Evaluation of Natural Gas Combined Cycle Should Have Been Required by KDHE. The June 2010 B&V study does not reflect the dramatic decrease in natural gas prices that occurred between the initial August 2006 study and 2010, or the dramatic increase in the capital cost of pulverized coal units over the same time period. These developments have reversed the cost-effectiveness of natural gas combined cycle plants and pulverized coal

[37] The Tidd PFBC project at Brilliant, Ohio is an example of an unsuccessful project by AEP. The gas turbine operated in the PFBC flue gas environment but failed to meet performance requirements for reasons unrelated to the PFBC technology. See: http://www.osti.gov/bridge/purl.cover.jsp;jsessionid=779D42A82E62AE27000618E2947F615F?purl=/786183-HMtEXL/native/.

plants relative to 2006. Natural gas combined cycle plants are demonstrably more cost-effective, in terms of levelized cost-of-energy, in 2010. The assertion in the Tri-State/Holcomb January 13, 2010 air permit application (p. 1-12) that natural gas combined cycle generation is too expensive for baseload needs is incorrect. A new natural gas combined cycle plant will produce lower-cost electricity than the proposed SCPC unit. Natural gas combined cycle generation would also reduce CO_2 emissions by nearly 60 percent compared to the proposed SCPC unit.

KDHE Response:

This comment is incorrect as a matter of both law and fact. Please refer to Comments 39 (SC VI.A) and 97 (PE III).

Comment 103 (Mr. Powers Comment IX):

Distributed solar PV meets renewable portfolio compliance target identified by Tri-State at comparable cost to SCPC generation and with no CO_2 emissions.

KDHE Response:

KDHE is not authorized to address to renewable portfolio compliance targets connection as part of the application review. Please refer to Comment 37.

Part 1 of the Application, as updated, at 1-12, indicates renewable energy sources, including solar, are not an available alternative to H2:

> ***Renewable energy (wind, solar, hydro, etc.) and biomass resources were not selected****. While renewable forms of electricity generation are becoming more viable, they cannot economically satisfy the large base-load requirements of the Participants. Pursuant to a voluntary, unwritten agreement reached by Governor Kathleen Sebelius and the investor-owned and cooperative utilities in 2007, Sunflower and Mid-Kansas already operate wind resources that satisfy the voluntary target of 10 percent of projected retail capacity obligation for 2010. Midwest Energy likewise meets this voluntary commitment. Additionally, the Sunflower-State Agreement contains further requirements for Sunflower's use of renewable energy sources.*

See also, In re Prairie State Generating Co., PSD Appeal No. 05-05, Slip op. at 41 (EAB 2006), aff'd sub nom Sierra Club v. EPA, 499 F.3d 653 (7th Cir. 2007) (finding similar responses from Illinois EPA regarding use of wind and solar in lieu of the proposed coal-fired power plant sufficient to respond to comments calling for consideration of alternatives). Solar photovoltaic is not a baseload resource and costs prohibitively more than SCPC (based on all-in levelized cost of energy).

Comment 104 (Mr. Powers Comment X):

KDHE did not perform a BACT analysis for CO_2. Setting aside the legal question whether BACT is required for CO_2, it is clear that CO_2 emissions can be minimized by increasing the

efficiency of the electrical generation process, or by capturing and sequestering the CO_2 produced in appropriate underground formations, or by alternative means of generation like natural gas combined cycle or solar PV that have inherently lower CO_2 emissions.

KDHE Response:

Please refer to Comments 37, 39, 97, 98, 99, 101, and 103.

Comment 105 (Mr. Powers Comment XI):

BACT for CO_2 would be distributed solar PV. It would result in zero CO_2 emissions at a cost incrementally less than the LCOE for the proposed SCPC unit (at the time of the 2016 start date) without considering the impact of CO_2 emission fees. Two additional low CO_2 emission scenarios, solar PV combined with natural gas combined cycle generation and stand-alone natural gas combined cycle generation, have lower levelized cost-of-energys than the proposed SCPC unit without considering the impact of CO_2 emission fees. The cost per ton of CO_2 removed approaches zero, $3/ton, for IGCC with 90 percent CO_2 capture when the cost of a nominal $15/ton CO_2 emission fee is included in the cost of generation for the proposed SCPC unit.

KDHE Response:

Please refer to KDHE Responses to Comments 103 and 104.

E. COMMENTS FROM GREAT PLAINS ALLIANCE FOR CLEAN ENERGY (GPACE) (Comments 106-139)

Comment 106 (GPACE Comment A.1.):

Coal Types and Associated Sulfur Content. Limiting sulfur to 0.5% on an annual average weight basis is not sufficient. In fact, based on USGS data, the ability to limit coal to 0.5% sulfur is suspect. Sulfur content of PRB coal (USGS data) indicates average sulfur content of 0.74%. The issue of coal sulfur content is further developed in section B.10 of these comments.

KDHE Response:

Please refer to KDHE Response to Comment 118.

Comment 107 (GPACE Comment A.2.):

The 5% Kansas Coal Requirement Under Kansas Law. GPACE states that a new coal-fired unit is built in Kansas should comply with Kansas law. In reviewing the draft air permit for the proposed plant, no emissions or economic modeling whatsoever can be found regarding the statutory requirement to use at least 5% of Kansas coal in the plant's fuel mix. GPACE claims this omission is especially glaring regarding SO_x emissions and the

likelihood that Kansas coal will contain high levels of sulfur, impacting the unit's ability to achieve adequate controls. Such non-compliance could be avoided if the project is adequately prepared and the draft permit includes sufficient modeling to demonstrate the applicant's willingness to comply with the Kansas statute. It appears that this exclusion of specific modeling data could lead to a violation of current state law.

KDHE Response:

Sunflower will be obligated to fully comply with all Kansas statutes. However, K.S.A. 66-1280 does not require Sunflower to use Kansas coal at all times and under all conditions. The pertinent section of the Kansas law (K.S.A. 66-1280) reads as follows:

> *(a) Any new coal-fired electricity generating facility in Kansas, construction of which commences on or after the effective date of this act, shall purchase Kansas coal for at least 5% of its coal requirements. For the purposes of this section, ''Kansas coal'' shall have the meaning ascribed thereto in K.S.A. 2008 Supp. 79-32,228, and amendments thereto.*
>
> *(b) The provisions of this section shall apply if the cost of the Kansas coal, including costs of transportation and handling at the new coal-fired electricity generating facility, is:*
>
> *(1) Competitive to the cost of the out-of-state coal supply the owner or operator of the new coal-fired electricity generating facility is using to meet its remaining coal supply requirements;*
>
> *(2) sold on comparable contractual terms and specification; and*
>
> *(3) of an acceptable quality for use in the new coal-fired electricity generating facility.*
>
> *This section shall not apply if the use or purchase of Kansas coal will result in the owner or operator of the new coal-fired electricity generating facility violating its air permit or a contractual obligation to which the owner or operator is subject.*

New Section 31 requires Sunflower to use Kansas coal in the operation of H2 under certain circumstances. For example, if Sunflower determines that Kansas coal is not of "competitive cost" or "an acceptable quality" or would cause Sunflower to violate its air permit, it is under no obligation to purchase and use the coal. The relative economic benefits and assumptions cited in the comment are not relevant to the issuance of the permit or the establishment of applicable emissions limitations. The air quality modeling performed to demonstrate compliance, meets all applicable regulatory requirements and guidance.

Comment 108 (GPACE Comment A.3.):

KDHE Independent Demonstration. The Significant Impact Levels and increment consumption determinations are not well explained. Best Available Control Technologies (BACT) selection rationale as determined by the KDHE (rather than the applicant) should be presented in the public record.

The applicant requested the pre-construction monitoring required under the Prevention of Significant Deterioration (PSD) be waived. KDHE states, "As approved by KDHE, in lieu of pre-application ambient monitoring data, the facility will use representative monitoring data for these pollutants from state monitoring sites located at Cedar Bluff and Dodge City" (page 10, Air Quality Impact Review). KDHE does not explain its rationale that these sites, located more than 50 and 80 miles distant, are representative of background concentrations at the HEP site.

KDHE Response:

For SILs information, please refer to KDHE Response to Comment 43.

For information about BACT please refer to Section III.B. KDHE has reviewed and concurred with the emission estimates and BACT reviewed contained in the permit application and in the public record. The permit summary sheet summarizes KDHE's conclusions.

See KDHE response to Comments 47 and 49 for information on using data from existing monitoring sites. The monitors selected for use in the H2 ambient impact analysis are located at sites that are characteristic of air quality across a broad region, including the area where Holcomb Station is located. In western Kansas, there is little industrial activity, and the regional airshed remains consistent across much of the state. The locations of air monitoring stations and the distances from Holcomb Station to these stations were clearly identified.

Both the Cedar Bluff and Dodge City sites are adequate to be used in developing a reasonable, worst case estimate of the air quality impacts of the proposed Holcomb expansion. The Cedar Bluff monitoring site was used to establish $PM_{2.5}$ and SO_2 background values. This site was established by KDHE to provide a regional look at ambient air quality in central and western Kansas and to serve as the Kansas background site. It is the closest monitoring site for $PM_{2.5}$ and SO_2 to the proposed Holcomb expansion project. KDHE has mapped and reviewed the point source emissions inventory and reviewed the number and location of ground level and elevated point sources of $PM_{2.5}$ and SO_2 emissions as part of the original siting of the monitor and as part of the review process for the Holcomb expansion. We have concluded that Cedar Bluff is very good for use as a $PM_{2.5}$ and SO_2 background site due to the very limited number of large $PM_{2.5}$ and SO_2 point sources in that part of Kansas and surrounding states.

The Dodge City monitor location site meets the criteria of providing representative, current data of sufficient quality. It is the closest PM_{10} monitor to the proposed Holcomb expansion.

The Dodge City monitor provides a regional look at ambient air quality in southwest Kansas. Using PM_{10} results from the Dodge City monitoring site to establish a background value for the Holcomb expansion is appropriate as the number and type of sources of PM emissions in the vicinity of the Dodge City site are similar to those for Holcomb.

Comment 109 (GPACE Comment B.1.):

Emission Limits. The draft permit does not provide any short term emission limits.

KDHE Response:

Please refer to KDHE Response to comment 42 for NO_x and SO_2.

Results from the screening modeling for CO showed the predicted effect of H2 to be less than five percent of the significance threshold for the 1-hour and 8-hour standard. Thus, a short term limit for CO was not deemed necessary to protect the NAAQS since the impact of the proposed project is well below the significance impact level.

Emission estimates used for the purposes of the permit, in air quality dispersion modeling, and other requirements are representative of maximum expected emission rates for time periods applicable to meet regulatory requirements and protect the NAAQS. Therefore, additional permit limits are not needed.

Comment 110 (GPACE Comment B.2.):

Potential CO_2 Issues. Neither the application, the draft permit, nor the permit summary address CO_2 emissions, controls and the very real regulations that will apply in January 2011.

KDHE Response:

Please refer to KDHE Response to Comments I, 208,209 and 210.

There is no current requirement that Sunflower consider "carbon" or CO_2 capture and sequestration alternatives. KDHE has addressed in the draft permit all applicable legal requirements in accordance with all current requirements. Future changes in statutory or regulatory requirements applicable to Holcomb 2 will be applied to Sunflower accordingly.

Comment 111 (GPACE Comment B.3.):

Natural Gas as BACT. The application's BACT review fails to properly take into account natural gas as a "clean fuel" option.

KDHE Response:

Please refer to KDHE Response to Comments 39, 150,151, and 156 .

Comment 112 (GPACE Comment B.4.):

BACT for Greenhouse Gasses and Related Issues. The application similarly fails to make any BACT determination – or *any* emissions limits or controls determinations – for greenhouse gases such as carbon dioxide.

KDHE Response:

Please refer to KDHE Response to Comments I, 38, 209, and 210.

Comment 113 (GPACE Comment B.5.):

Coal Selection Study and Out-of-State Customers Issues. The KDHE should address the degraded air quality in Kansas to serve out of state customers.

KDHE Response:

KDHE does not regulate commerce between states. The final permit does include emission limitations along with monitoring and recordkeeping requirements to ensure air quality protection.

Comment 114 (GPACE Comment B.6.):

State Energy Efficiency Issues Customers Issues. The applicant does not address how energy efficiency plans are to be incorporated into its planning.

KDHE Response:

While energy efficiency efforts are welcomed by KDHE, these are beyond the jurisdiction and authority of the state. Please refer to KDHE Response to Comment A.

Comment 115 (GPACE Comment B.7.):

Coal Plants Shutting Down in other Areas of the Country. KDHE should address why a coal plant burning coal from Wyoming should be built in Kansas.

KDHE Response:

Please refer to KDHE Response to Comment 152.

KDHE does not regulate commerce between states. The final permit does include emission limitations along with monitoring and recordkeeping requirements to ensure air quality protection.

Comment 116 (GPACE Comment B.8.):

Particulate Matter (PM), PM_{10} and $PM_{2.5}$. The permit application and draft permit specify total PM_{10} and $PM_{2.5}$ limits of 0.018lb/MMBTU with compliance demonstrated by six 120-minute tests. If the tests don't show "consistent compliance" (pg 9, Draft Permit 9/21/10) then the limit for PM_{10} and $PM_{2.5}$ emissions can be changed to 0.025 lb/MMBTU. It appears that Sunflower does not anticipate meeting the 0.018 lb/MMBtu limit as annual emissions at 0.018 lb/MMBtu would be 685 tpy rather than the proposed 748 tpy. At the upper-range of 0.025 lb/MMBtu, total PM_{10} and $PM_{2.5}$ emissions would be 952 tpy. PM emissions – limited in the draft permit to 0.012 lb/MMBTU would be estimated to be 458 tpy. Where does the 512 tpy emission limit in table B-1.1 originate? Please confirm what emission rate was used in proposing the emission limits in the draft permit and shown in Table B.1-1 above. KDHE needs to make the facility's permit limits internally consistent.

PM, PM_{10}, and $PM_{2.5}$ should have short term emission limits. Further, it appears that Sunflower will be using the CMS results as if all PM is PM_{10} and $PM_{2.5}$; however, this interpretation is not clearly articulated in the draft permit or permit summary. Please confirm if the above understanding is correct and provide clarification in the Draft Permit.

KDHE Response:

Please refer to KDHE Response to Comments 59 and 132.

The 512 tons per year emission limit is calculated from a filterable PM limit of 0.012 lb/MMBtu from H2, combined with other particulate sources that are part of the expansion project.

Per 40 CFR Part 60.48a (o) and (p) from Subpart Da-"Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978"; an owner or operator may elect to install, evaluate, maintain, and operate either a COMS or a CEMS measuring PM emissions discharged from the affected facility to the atmosphere and record the output of the system accordingly.

Emission estimates used for the purposes of the permit in air quality dispersion modeling and other requirements are representative of maximum expected emission rates for time periods applicable to meet regulatory requirements and protect the NAAQS. Therefore, additional permit limits are not needed.

Please refer to the permit language clarifying PM, PM_{10}, and $PM_{2.5}$. The CMS results will include filterable PM. PM_{10} and $PM_{2.5}$ will include filterable and condensable particulate.

Comment 117 (GPACE Comment B.9.):

Ozone. Why does the latest AQIA not evaluate VOCs for ozone compliance if CAMx modeling was performed previously?

Why was the potential nonattainment status for ozone at the region not addressed? In the event that new ambient air quality standards are released prior to the issuance of this permit, Sunflower and KDHE should demonstrate how public health is achieved. Why was the proposed secondary standard not addressed in the application, the air quality impact analysis, the draft permit summary, nor the draft permit itself?

KDHE Response:

KDHE does not require a PSD permit applicant to perform ozone modeling, as there is no approved model, including the CAMx model, to assess ozone impacts from a single source. The analysis provided by Sunflower was consistent with demonstrations made by other applicants across the country and adequately demonstrated that emissions from H2 should not impact compliance with the 8-hour NAAQS.

Sunflower's Application addresses all applicable legal requirements. Future changes in statutory or regulatory requirements applicable to Holcomb 2 will be applied to Sunflower accordingly. Please refer to KDHE Response to Comment 48.

Comment 118 (GPACE Comment B.10.):

Sulfur Dioxide (SO_2). GPACE asserts that limiting sulfur to 0.5% on an annual average weight basis is not sufficient and based on USGS data, the ability to limit coal to 0.5% sulfur is suspect claiming sulfur content of PRB coal (USGS data) indicates average sulfur content of 0.74%.

KDHE Response:

Please refer to Section III.A and KDHE Response to Comment 42. The CAA does not require KDHE to implement the new regulatory requirements contained in the comment (1-hour SO_2 NAAQS).

Sunflower is obligated by the permit terms and conditions to satisfy all emissions limitations established by the permit, regardless of coal quality and regardless of any Kansas statutory coal use requirements.

While the Application reflects Sunflower's present intention to rely on coal supplies primarily from the Powder River Basin in Wyoming, it also provides for comparable coal from other sources. Purposefully, the permit does not limit Sunflower's coal to any single source or supply so long as the coal meets the criteria necessary to enable Sunflower to meet the emissions limitations in the permit (including the BACT emissions limitations, the average annual fuel sulfur content, and the constraints related to assuring the 10 and 25 tons per year emissions limitations for HAPs are not exceeded in any rolling 12-month period).[38]

[38] Historically Sunflower has used three to five different mines each year to meet its energy production obligations. The current coal contracts require fuel sulfur content to be no greater than 0.5%. That sulfur value, combined with a minimum heat value of 8100 Btu/lb, yields the 1.23 lb-SO_2/MMBtu permit limitation.

The permit conditions relating to coal sampling and analysis provide adequate assurance the coal will meet the permit conditions.

Sunflower will monitor the inlet sulfur content of coal burned in the operation of H2 to ensure compliance with all permit sulfur content requirements. If Sunflower does not comply with all such requirements, it will be subject to the consequences provided by applicable law. Sunflower's coal contract requires sulfur levels to be no greater than 0.5%, and there is no reason to believe that it will not be able to procure sufficient low-sulfur coal for use by H2 to meet its permit obligations.[39] *The recent historical sulfur analyses for 575 individual coal samples from deliveries to H1*[40] *in years 2005 through 2009 ranged between 0.28% and 0.38% percent annually*[41]*. This is a strong indicator that fuel supply quality can be controlled contractually to meet the 0.5% sulfur permit requirement.*

Considering only the USGS PRB coal data in reaching conclusions disregards common coal contract terms management and/or blending methods in use today to achieve compliance with express contract or permit limitations.

Comment 119 (GPACE Comment B.11.):

Nitrogen Dioxide (NO_2). Nitrogen Dioxide (NO_2) emissions should have permit limits commensurate with demonstrating compliance with a one-hour NAAQS.

KDHE Response:

Please refer to Section III.A. The CAA does not require KDHE to implement the new regulatory requirements contained in the comment (1-hour NO_2 NAAQS).

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[39] Sunflower previously provided KDHE with an analysis of 4588 PRB mine samples reported for 17 mines in the PRB based upon data provided to the USDOE for calendar year 2004 (see e-mail from Wayne Penrod to KDHE dated 11/19/10 and permit record). This data was used to calculate the upper 97.5% confidence interval value for fuel SO_2. A cursory review of the tabled data indicates that nine of these mines could supply the fuel without presenting any need to blend them to comply with the 1.23 lb/MMBtu Dry FGD inlet SO_2 limitation.

This conclusion can only be enhanced by an identical presentation of PRB sulfur data for 2009. This analysis of 5962 PRB mine samples reported for 18 mines in the PRB based upon data provided to the USDOE for calendar year 2009. This data was used to calculate the upper 97.5% confidence interval value for fuel SO_2. A cursory review of the tabled data indicates that 13 of these mines could supply the fuel without presenting any need to blend them to comply with the 1.23 lb/MMBtu Dry FGD inlet SO_2 limitation. A copy of this summary page is also attached.
Further, other mines supply their own blended fuel from different seams (as at Jacobs Ranch) or from different zones within a seam to meet contract guarantee requirements. Finally, Sunflower could choose to blend different fuel supplies on-site, as it did during the 2004 mercury control test-burn demonstration. Sunflower calculates that only 3 mines in the PRB (Absaloka, Rosebud #6, and Wyodak) would be unable to supply substantial amounts of coal without encroaching on the 1.23 lb/MMBtu Dry FGD inlet limitation, unless more sophisticated blending operations were undertaken.

[40] A single composite ASTM mine sample analysis accompanies each unit train delivery.

[41] Fuel sulfur weighted average analysis – all trains: 2005 – 0.38%, 2006 – 0.29%, 2007 – 0.28%, 2008 – 0.32%, 2009 – 0.33%.

Please refer to KDHE Response to Comment 42.

Comment 120 (GPACE Comment C.1):

Hazardous Air Pollutants (HAPs) - Hydrochloric Acid (HCl). Sunflower estimates HAP emissions from HEP using stack test data from H1. The HAP emissions appear very low from H1. Our analysis indicates the HCl emissions should be considered a major source of HAPs.

KDHE Response:

Please refer to KDHE Response to Comments 51, 52 and 53. Sunflower used actual coal test data to reference the HCl emission estimate generated using the EPRI emission factors and the site specific test measurements to enable coal sampling and analysis methods to provide assurance of non-major status. The chlorine content of the PRB coal was 7 µg/g during the test period. The chlorine data relied on by the commenter appears to be based on the detection limit of the older test methods (50 to 200 µg/g)[42] that were widely used in analyzing coal samples before 2001 and thus not indicative of the actual chlorine content of PRB coal samples. In contrast, the analyses performed by Sunflower had a detection limit between 6-22 µg/g. Ultimately, Sunflower relied on the actual H1 test data in preparing the HCl emission estimate for H2. See also KDHE's Response to Comment 13.

Comment 121 (GPACE Comment C.2):

Hazardous Air Pollutants (HAPs), Hydrofluoric Acid (HF). Using information from EPRI and from the USGS related to PRB coal, HF emissions would be estimated at 13.98 tpy (97% control, 2% bypass). Like for HCl above, this acid exceeds major source thresholds.

KDHE Response:

Please refer to KDHE Response to Comments 51, 52, and 53.

Sunflower also used actual coal test data to reference the HF emissions generated using the EPRI emission factors. Based on that data, the fluorine content of the coal is 80 µg/g, and Sunflower relied on the actual H1 test data in preparing the HF emission estimate for H2. See also KDHE Response to Comment 13.

[42] ASTM D4208-02 Standard Test Method for Total Chlorine in Coal by the Oxygen Bomb Combustion/ION Selective Electrode Method.

Comment 122 (GPACE Comment C.3):

Metal HAPs. The calculations for metals HAPs needs to be more clearly explained. The emission rates using EPRI emission factors are three times greater than when using H1 data, according to the applicant. It is unknown if these emission rates from H1 are an appropriate basis for the emission estimate. It is also unknown if the proposed emission rates include periods during which emissions are uncontrolled (startup, shutdown, malfunction, bypass).

KDHE Response:

Sunflower's metallic HAPs emissions estimates are provided in Part 1 of the updated Application materials. As shown on page 1-28, the total metal HAPs emissions estimate is 2.02 tons per year using the H1 test data. In addition to the discussion provided in Part 1, Sunflower also provided an analysis[43] describing the methodology followed to estimate metallic HAPs emissions in the original February 2006 Application. KDHE has reviewed those data, which were available for public review during the comment period.

The permit requires verification of the accuracy of these Sunflower estimates by post-construction stack testing. Additionally, the permit contains effective limits on the H2 PTE, specifically through the application of the Dry FGD and fabric filter; and compliance with these emissions limitations is assured by the permit's monitoring, recordkeeping, and reporting requirements.

Comment 123 (GPACE Comment C.4):

HAP Performance Testing and Records. HAP performance testing should be conducted both at the inlet to the control device and at the stack exhaust. The inlet data will be used to establish an emission factor during bypass periods. The draft permit should address both the inlet and outlet testing requirements. Additionally, bypass time should be limited in the permit to both a duration for any single event as well as total bypass time for a rolling 12 month period.

KDHE Response:

HAP testing at the inlet to the control and at the stack exhaust is included in the final permit for HF and HCL. These two HAPs are the main contributors to the bulk amount of HAPs emissions. Additional performance testing for other HAPs is included in the Compliance and Other Performance Testing section of the final permit.
There is no bypass of the FGD.

Comment 124 (GPACE Comment D.1):

General Modeling Comments**.** Why did Sunflower not include in the refined analysis receptors that did not exceed the SIL?

[43] Estimates for Hazardous Air Pollutants – Holcomb Generation Expansion (H2, H3, and H4) – Appendix L.

KDHE Response:

The purpose of the required air quality analysis as directed by EPA 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 (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable NAAQS or PSD increment.*[44]

As further delineated by EPA:

> *When a violation of any NAAQS or increment is predicted at one or more receptors in the impact area, the applicant can determine whether the net emissions increase from the proposed source will result in a significant ambient impact at the point (receptor) of each predicted violation, and at the time the violation is predicted to occur. The source will not be considered to cause or contribute to the violation if its own impact is not significant at any violating receptor at the time of each predicted violation. In such a case, the permitting agency, upon verification of the demonstration, may approve the permit.*[45]

According to EPA's guidance document, if an exceedance is modeled at a receptor but the proposed project does not have a significant impact at that receptor at the time of the predicted violation, then it is not causing or contributing to that exceedance. If the initial significant impact modeling indicates that the proposed project does not have a significant impact at a receptor at any time during the 5-year modeled meteorological period (i.e., all impacts from the proposed project are less than the relevant SIL), then there is no possibility that the refined modeling will show that when additional sources are added into the model that the impacts from the proposed project will exceed the SIL. Removal of any receptors at which the proposed project demonstrates that all impacts over the entire 5-year modeled meteorological period are less than the relevant SIL is appropriate.

Comment 124 (GPACE Comment D.1) cont'd:

In the August 2010 modeling, Sunflower used meteorological data provided by KDHE. GPACE claim that it is inappropriate to run the model with meteorological data missing.

KDHE Response:

The meteorological data compiled for AERMOD are deemed valid and representative by KDHE. The number of calms and missing data reported when AERMOD was run are not unusual. Substitution of data from another meteorological station site should only be done

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44 EPA DRAFT NSR Workshop Manual. Chapter C: The Air Quality Analysis, page C.1. 1990

45 EPA DRAFT NSR Workshop Manual. Chapter C: The Air Quality Analysis, page C.52. 1990

when it can be clearly shown that the substitution station is representative of the primary station.

As detailed in Section 1.5.4 of Part 5.0 of Sunflower's Application, as updated, the data was processed by KDHE and provided to Sunflower for use in the air dispersion model.

Comment 125 (GPACE Comment D.2):

Oxides of Nitrogen (NO_x) Modeling. Sunflower did not complete Significant Impact Modeling for Holcomb Expansion Project (HEP). Instead, Sunflower assumed the modeled concentration for the HEP would exceed the SIL for the NO_2 1-hour standard and extended the receptor grid 50 km. This designated significant impact area includes modeled concentrations from the HEP of 5 µg/m3 which is less than the SIL of 7.5 $\mu g/m^3$. This is not consistent with the methodology Sunflower implemented for the Cumulative modeling of SO_2 and PM_{10} where receptors with modeled concentrations from HEP less than the SIL were removed. Why did Sunflower extend its receptor grid to 50 km for the 1-hour NO_2 modeling?

KDHE Response:

Please refer to Section III.A. The CAA does not require KDHE to implement the new regulatory requirements contained in the comment (1-hour NO_2 NAAQS).

A preliminary analysis was not conducted to evaluate the SIL and whether or not the Expansion Project would exceed the SIL because, as indicated in Section 2.1 of the August 2010 NO_2 modeling report, it was reasonably assumed that the significant impact area would extend to 50 km. The air modeling analysis for NO_2 is different from the analysis used for other pollutants (PM_{10}, CO, SO_2) because most of the emissions from the stack are nitric oxide (NO) rather than NO_2, which is the oxide of nitrogen for comparison with the NAAQS. AERMOD is a Gaussian dispersion model that uses a single meteorological station and is essentially limited to a maximum distance of 50 km. Its use beyond this distance yields uncertain results.

Sunflower used a lower, more conservative SIL for NO_2 than the SIL established by KDHE in the September 22, 2010 memorandum. This approach is acceptable since the facility may choose to take a more conservative approach in their analyses.

Comment 125 (GPACE Comment D.2) cont'd:

Why is the 1-hour NO_2 emission factor for H1 listed to be 1,814.5 lb/hr in the PSD Application but in the modeling runs the emission factor used 1,558.94 lb/hr?

KDHE Response:

Please refer to Section III.A. The CAA does not require KDHE to implement the new regulatory requirements contained in the comment (1-hour NO_2 NAAQS).

The NO_2 limit for H1 used for modeling purposes is 1558.94 lb/hr. This limit is calculated from the name plate heat input rate of 3390 MMBtu/hr times the acid rain permit limit of 0.46 lb/hr. The 1-hr NO_2 emission rate included on Table 7, page 12 for H1 from the Sunflower Air Dispersion Modeling Analysis – NO_2 1-hr NAAQS Update 8/19/2010 is incorrect due to a typographical error. Thus, there is no need to revise the refined modeling.

Comment 125 (GPACE Comment D.2) cont'd:

The applicant must justify and obtain Regional EPA Office approval for the modeling protocol. The approval of the Regional EPA Office for this modeling approach was not referenced in the applicant's submittal and is not a part of the public record.

KDHE Response:

Please refer to Section III.A. The CAA does not require KDHE to implement the new regulatory requirements contained in the comment (1-hour NO_2 NAAQS).

Please refer to KDHE Response to Comment 46.

As to the specific point that PVMRM needs to be approved by the EPA Region in question, all modeling data, databases, assumptions, and results were provided to EPA Region 7 for review and comment. EPA provided official comments on October 22, 2010, and the agency's response specifically addressed PVMRM. In this response, EPA did not object to Sunflower's use of the PVMRM model. Instead, EPA indicated only that there needed to be sufficient justification for the use of the model, the modeled parameters, and that KDHE follow the guidance set forth in the EPA June 28, 2010 memorandum discussed in detail above. All aspects of that memo were adequately addressed, which allows for the use of PVMRM to demonstrate compliance with the new 1-hour NO_2 NAAQS.

Comment 125 (GPACE Comment D.2) cont'd:

The applicant and KDHE should consider the EPA Guidance regarding the NO_2/NO_x conversion ratio. The applicant uses the national default value of 0.75 and GPACE requests justification for the use of this ratio instead of the upper bound NO_2/NO_x ratio of 0.90.

KDHE Response:

Please refer to Section III.A. The CAA does not require KDHE to implement the new regulatory requirements contained in the comment (1-hour NO_2 NAAQS).

A value of 0.75 was used for the ambient equilibrium NO_2/NO_x ratio in the modeling runs, which was determined to be appropriate for this modeling scenario. AERMOD has a default setting of 0.90 (90%), but a review of this information indicated that this does not correspond with current EPA practices and modeling demonstrations outlined in 40 CFR 51 Appendix W. Tier 2 (ARM) of the Appendix W three-tier approach recommends the use of an empirically derived NO_2/NO_X ratio of 0.75 (75%) on an annual basis. Referring to the memorandum issued by Tyler Fox on June 28, 2010, the Tier 2 methodology is explained in greater detail, and the justification for when and where the 0.75 ratio is discussed.

In general, for low-level releases with limited plume rise, peak hourly NO_x impacts are likely to be associated with night-time stable/light wind conditions. Since ambient ozone concentrations are likely to be relatively low for these conditions, and since low wind speeds and stable atmospheric conditions will further limit the conversion of NO to NO_2 by limiting the rate of entrainment of ozone into the plume, the 0.75 national default ratio will likely be conservative for these cases.

A review of the database used for the NO_2 NAAQS inventory reveals that the dominant stack heights are approximately 30 feet, making them all low level releases. In the inventory of 387 sources, the average stack height was 32.5 feet and the median stack height was 27.8 feet, demonstrating that these sources are characterized as low level releases. While there are some taller stacks in the overall model, it is not necessary to increase the ratio to 0.9 to account for these few sources and lead to an over prediction of the impacts from the predominantly low-level releases prevalent in the model. This is further demonstrated by examining the results of the 1-hour NO_2 model and understanding that the high impacts that are recorded are primarily a result of the low-level release stacks, further emphasizing the appropriateness of using 0.75 as the ratio.

Of greater significance is that 0.75 is also the value EPA used in its risk and exposure assessment to support the new 1-hour NO_2 NAAQS, and is appropriate or conservative for the modeling for this project.[46] *As EPA has used this ratio in their assessment of the 1 hour NO_2 NAAQS, it was determined that it was also appropriate to use for the modeling of this project. As such, the ratio was set to 0.75.*

Sunflower provided documentation of NO_2/NO_x in stack ratios and references, which contain justifications for their use, in the Air Dispersion Modeling Analysis for Compliance with the Nitrogen Dioxide 1-Hour NAAQS, submitted August 19, 2010, pages 13-15. KDHE has reviewed these ratios and concurs with their usage.

All modeling data, databases, assumptions, and results were provided to EPA Region 7 for review and comment. EPA provided official comments on October 22, 2010 and KDHE Response to Comment 27 specifically dealt with PVMRM. In this response, EPA did not object to the use of the PVMRM model or the defaults values used (i.e. NO_x/NO_2 conversion ratio).

[46] EPA Doc. # EPA-452/R-08-008a, "Risk and Exposure Assessment to Support the Review of the NO_2 Primary National Ambient Air Quality Standard" (Nov. 2008).

When determining the nearby sources to include in the inventory, KDHE followed 40 CFR Part 51, Appendix W, §8.2.3.b. (adopted by reference in K.A.R. 28-19-350(d)):

> *All sources expected to cause a significant concentration gradient in the vicinity of the source or sources under consideration for emission limit(s) should be explicitly modeled. The number of such sources is expected to be small except in unusual situations. Owing to both the uniqueness of each modeling situation and the large number of variables involved in identifying nearby sources, no attempt is made here to comprehensively define this term. Rather, identification of nearby sources calls for the exercise of professional judgment by the appropriate reviewing authority...*

Many factors went into KDHE's decision concerning which nearby sources are expected to cause a significant concentration gradient, including availability of accurate emissions data.

An inventory of all NAAQS sources was provided by KDHE for an area extending 100 km from Holcomb Station. This inventory was thoroughly reviewed and each individual source categorized so as to properly assign the specific type of activity to each source. This allowed for accurate categorization in the modeling analysis.

Comment 125 (GPACE Comment D.2) cont'd:

GPACE requests additional justification and rationale for the use of the PVMRM, the background data used, its variability over time, and the missing data procedures used. According to the PSD Application the background concentration to fill in missing data from the ozone data is 37 ppb. Why was 34 ppb used for the modeling runs?

KDHE Response:

Please refer to Section III.A. The CAA does not require KDHE to implement the new regulatory requirements contained in the comment (1-hour NO_2 NAAQS).

Please refer to Response to Comments 27 and 46. KDHE concurs with the use of the PVMRM as the most accurate method of modeling NO_2 emissions from the project.

KDHE approved a value of 34 ppb for missing ozone data, and that value was used by Sunflower in the modeling. The Sunflower report contains a typographical error that incorrectly states the 37 ppb value.

Comment 125 (GPACE Comment D.2) cont'd:

The modeling for NO_2 includes a limit on the hours of operation for H1GEN and H2GEN for non-emergency operations. Are these limitations included in the permit?

KDHE Response:

Please refer to Section III.A. and KDHE Response to Comments 46 and 42. The CAA does not require KDHE to implement the new regulatory requirements contained in the comment (1-hour NO_2 NAAQS).

Limitations for H1GEN are not in the permit. There is no regulatory provision that requires permit limitations on existing sources at Holcomb Station due to the 1-hour NO_2 NAAQS. The 9AM to 6PM limit for non-emergency purposes for H2GEN is included in the permit.

KDHE developed an inventory, including 1-hour emission rates, in accordance with 40 CFR Part 51, Appendix W and supplied it to Sunflower for use in their model.

Comment 126 (GPACE Comment D.3):

Sulfur Dioxide (SO_2) Modeling. GPACE states that the SO_2 emission rates for H_2 are four times too low. The emission rates for worst case SO_2 emissions from HEP (as demonstrated previously in these comments) used in the modeling were more than four times too low. Additionally, nearby sources may not be accurately reflected in the emission inventories to the KDHE. It may be necessary to use the facilities' permits to determine worst case short term emissions.

KDHE Response:

Please refer to Section III.A. The CAA does not require KDHE to implement the new regulatory requirements contained in the comment (1-hour SO_2 NAAQS).

Please Refer to KDHE Response to Comment 42.

The 1-hour SO_2 rate Sunflower used (4,089 lbs/hr) to conduct dispersion modeling includes startup, shutdown and maintenance periods as per 40 CFR Part 51 Appendix W. KDHE developed an inventory in accordance with 40 CFR Part 51, Appendix W and supplied it to Sunflower for use in their model.

Comment 127 (GPACE Comment D.4):

$PM_{2.5}$ Modeling. "Sunflower should have used the most conservative approach in assessing whether refined modeling should be pursued. Since Sunflower used SIL's more than three times higher than the finalized levels, the modeling should be redone, and the public should have the opportunity to review and comment."

"The protocol for the refined modeling needs to detail how $PM_{2.5}$ emission rates of nearby sources will be determined. The EPA's Surrogate Policy no longer applies. The rationale and conclusions should be made available for public review along with the finalized refined modeling."

KDHE Response:

Please refer to Section III.A. The CAA does not require KDHE to implement the new regulatory requirements contained in the comment ($PM_{2.5}$ SILs).

Please Refer to KDHE Response to Comment 25, which defines how Sunflower has demonstrated compliance with the requirement to show that the source does not significantly impact the $PM_{2.5}$ NAAQS.

The KDHE Response to Comment 25 explains why refined modeling is not required to demonstrate compliance with the $PM_{2.5}$ NAAQS.

Since significance modeling indicated impacts less than the SIL, no refined modeling was done. Therefore, no nearby source inventory was supplied by KDHE for $PM_{2.5}$.

Please refer to the KDHE memorandum issued September 22, 2010 explaining the rationale for the $PM_{2.5}$ SILs.

Comment 128 (GPACE Comment D.5):

Ozone Modeling**.** "KDHE completed CAMx modeling; however, the CAMx modeling was used to demonstrate Visibility Impacts, only. Ozone was not specifically addressed. Since CAMx was completed for visibility purposes, and since CAMx is used in nearby states to demonstrate compliance with the 8-hour ozone standard, it is an acceptable model to assess compliance with the NAAQS for ozone…

KDHE Response:

Please Refer to KDHE Response to Comment 48.

Sunflower conducted an assessment of the potential impacts from both VOC and NO_x on ozone formation due to Holcomb 2. This information was submitted in Part 6.0 of the Application. The specific information regarding ozone compliance demonstration is contained in Section 1.1 of Part 6.0 and is a qualitative assessment of the ozone impacts. As indicated in the KDHE Air Quality Impact Analysis Review, EPA does not yet have an approved methodology for evaluating the 8-hour ozone standard.

EPA has in other permits recommended a qualitative approach to an ozone analysis, which was conducted for this project and indicates that Holcomb 2 will not cause a significant increase in the ambient ozone concentrations in the area. This was evaluated with respect to the current ozone monitored values in various areas, and all indicated compliance with the current 8-hour ozone NAAQS.

40 CFR Part 51, Appendix W addresses single source modeling for ozone. There is no guideline single-source model for ozone impact analyses in Appendix W. Estimating the ozone impact due to a single source is possible when using a regional ozone modeling

analysis. However, the modeling dataset needs to be appropriate for the intended use and the KDHE CAMx visibility dataset is not appropriate for an ozone analysis due to the grid spacing and the lack of a performance evaluation.

Holcomb Station is a facility located in rural Kansas, with no nearby nonattainment areas for ozone. The nearest ozone nonattainment area encompasses all or parts of six counties near Denver, Colorado. The nearest edge of this area (the eastern edge of Arapahoe County) to Holcomb Station lies approximately 300 km to the west-northwest. The predominant north/south wind pattern in this region will transport emissions from the Expansion Project away from the Denver, Colorado area. For these reasons, additional air quality modeling is not required.

Comment 128 (GPACE Comment D.5) cont'd:

In rural areas, NO_x can be a limiting factor for ozone formation. Thus, modeling for ozone should be completed to demonstrate compliance with the existing 0.075 ppm since nearly 2000 tpy of NO_x are being added to the air shed.

In addition the application should consider the potential nonattainment with the proposed 8-hour primary limits of 0.06 to 0.07 ppm as well as the proposed secondary standards."

KDHE Response:

Please refer to the discussion of ozone modeling above in this comment and to the KDHE Response to Comment 128 above.
EPA has not issued a final revision to the proposed 8 hour ozone NAAQS. As a result, the permit decision need not address the proposed standard.

Comment 129 (GPACE Comment E)

Increment Consumption. The applicant should provide documentation related to the available increment. What was the basis for the available increment as listed in the application? KDHE should provide a rationale for its acceptance of the modeled increment consumptions.

KDHE Response:

PSD increments are a limit on air quality impacts as defined in 40 CFR 52.21. PSD increments as defined in 40 CFR 52.21 are limits to increases in ambient pollutant concentration over the baseline concentration.

Air dispersion modeling to demonstrate compliance with the NAAQS and PSD Class II increment was conducted in full accordance with federal and state guidelines. Significant impact modeling, refined modeling (i.e., modeling conducted with additional NAAQS and/or increment consuming sources) was conducted for NO_2, SO_2 and PM_{10}. KDHE supplied nearby source inventory information to Sunflower for all NAAQS and increment consuming sources within the allotted study area. Guidelines in 40 CFR Part 51 Appendix W were

followed to compile the nearby source inventory. These sources were then factored into the air model. Compliance with all standards was demonstrated utilizing these sources.

Comment 130 (GPACE Comment F):

Best Available Control Technology (BACT). BACT determinations as presented in the permit summary are not incorporated in the permit.

KDHE Response:

Please refer to KDHE Response to Comments 39, 40, and 41.
A full BACT analysis was conducted for all pollutants required and the BACT limits were incorporated into the PSD permit.

Comment 130 (GPACE Comment F), cont'd:

NO_X. The Permit Summary does not identify which of the following options was selected:
In Combustor with post Combustion:

- LNB and OFA plus Selective Catalytic Reduction (SCR) (60% reduction)
- LNB and OFA plus Selective Catalytic Reduction (SCR) (72% reduction)
- LNB and OFA plus Selective Catalytic Reduction (SCR) (80% reduction)

Whichever option has been selected should be identified in the Permit Summary and in the Draft Permit. Additionally, the reduction requirement should be included in the Draft Permit.

KDHE Response:

Please Refer to KDHE Response to Comments 77, 78, 79 and 83.
BACT is an emissions limitation, not a removal efficiency. Please refer to CAA 169(3) and 40 CFR 52.21(b)(12).

Comment 130 (GPACE Comment F), cont'd:

SO_2. The Permit Summary states that BACT is Dry FGD with 92% removal. The 92% removal should be incorporated into the Draft Permit as a permit requirement.

KDHE Response:

Please refer to Comments 84, 85, 86, 87.
BACT is an emissions limitation, not a removal efficiency. Please refer to CAA 169(3) and 40 CFR 52.21(b)(12).

Comment 130 (GPACE Comment F), cont'd:

PM, PM_{10}, and $PM_{2.5}$ at the Boiler. The Permit Summary states BACT will be fabric filters with 99.81% reduction. The control efficiency should be incorporated into the Draft Permit.

Demonstration with compliance requirements should occur more frequently than the 30 day cycle as is proposed by the applicant and incorporated into the Draft Permit by KDHE.

KDHE Response:

Please refer to Comments 89, 90.

BACT is an emissions limitation, not a removal efficiency. Please refer to CAA 169(3) and 40 CFR 52.21(b)(12).

Comment 131 (GPACE Comment G1), cont'd:

Compliance Determinations – General comments. The permit summary (not the federally – enforceable permit itself) states that the BACT determinations for CO, VOC, and mercury may be revised if the limits specified in the permit cannot be consistently achieved. First, a BACT limit should not be set if there is concern that the unit cannot meet the standard. Second, modeling, increment consumption, preconstruction monitoring, and applicable regulations are based on the emission factors as proposed by the applicant. The construction permit should not provide the pathway for relaxation of permit conditions, especially not using a draft memo from 1985.

KDHE Response:

Please refer to KDHE Response to Comments 73, 91, and 92.

KDHE reviewed Sunflower's BACT analyses for VOC's and CO outlined in Section 4 of the permit application. These analyses describe the logic behind the variations of the amount of pollutants due to hierarchy amongst the criteria pollutants.

In regards to the mercury limit, KDHE Response to Comment 92 outlines the reasoning and regulatory requirement for the mercury limits contained within the permit. Mercury is not subject to regulation under PSD. Therefore, the mercury limit is not a BACT review. Sunflower has signed an agreement stating that the combined mercury emission levels from H1 and H2 will not increase from the current emission level of H1 and that the permit will include a mercury limit of 0.020 lb/GWh forH2, which is an 80 percent reduction from the previous NSPS limit .

KDHE has and continues to follow the guidance from the 1985 memo referenced. The memo, amongst other items, addresses public participation requirements for PSD permits.

There is a public participation requirement if the permit limits, for any pollutant, are relaxed for any reason.

Comment 132 (GPACE Comment G2):

PM. The application states PM_{10} and $PM_{2.5}$ (filterable + condensable) limits will be 0.018 lb/MMBtu based on six 120-minute tests. However, if the facility cannot "consistently achieve" this emission "limit" then the draft permit allows for PM emissions of up to 0.025 lb/MMBtu.

What emission rate is considered BACT? Why specify two different emission "limits" with an almost 50% difference? The KDHE should provide its rationale for this permit condition for public review and consideration. Also, why should the determination be based on stack testing rather than on the continuous monitoring system results?

As mentioned previously in these Comments, the PM, PM_{10}, and $PM_{2.5}$ emission limitations are not internally consistent. The relationships between the BACT determination, the control efficiency of the baghouses, and the annual emission limits should be consistent.

KDHE Response:

Please refer to KDHE Response to Comments 59, 89, 90.

The emission rate in the permit is considered BACT and multiple emission rates were utilized for reasons outlined in the comments referenced and in Part 4 of the permit application.

40 CFR 60.48Da(p) allows for the use of a PM CEM as an alternative to meeting the compliance provisions specified at 40 CFR 60.48Da(o) related to opacity:

> *The owner or operator may elect to install, evaluate, maintain, and operate a CEMS measuring PM emissions discharged from the affected facility to the atmosphere and record the output of the system as specified in paragraphs (p)(1) through (p)(8) of this section…*

A continuous monitoring system for PM is required to demonstrate compliance with the filterable PM emissions limitation. There is no continuous monitoring system available to monitor PM_{10} or $PM_{2.5}$ alone. There is no continuous monitoring system available to monitor condensable particulate emissions.

Comment 133 (GPACE Comment G3):

Mercury. Page 16 of the draft permit seems to indicate that Sunflower may choose either a stack test or a CEMS. GPACE would ask that KDHE specifically identify how compliance will be demonstrated especially in light of the following guidance from EPA:
"However, EPA encourages all States to consider requiring continuous monitoring (except perhaps for very small, low-emitting sources) to ensure continuous compliance, rather than relying on infrequent, short-duration data from stack tests".

KDHE Response:

Please refer to KDHE Response to Comment G.

The permit contains the following continuous monitoring requirements:

> *Within 180 days after initial full-load operation of the steam generator, Sunflower shall install and operate a continuous monitoring system, either a CEMs or sorbent trap, to monitor and record emissions of mercury as required by the permit.*

Comment 134 (GPACE Comment H):

Preconstruction Monitoring. What is KDHE's rationale for waiving the one year baseline monitoring data requirement? GPACE states that the H2 modeled concentration for PM10 is 12.28 ug/m3 and this exceeds the Significant Monitoring Concentrations (SMC) so pre-construction monitoring is required. GPACE also suggests that other pollutants be monitored as well.

GPACE states that the H2 modeled concentration for PM10 is 12.28 ug/m3 and this exceeds the Significant Monitoring Concentrations (SMC) so pre-construction monitoring is required. GPACE also suggests that other pollutants be monitored as well.

KDHE Response:

Refer to Section III.A. The CAA does not require KDHE to implement the new regulatory requirements contained in the comment ($PM_{2.5}$ SMC).

Refer to KDHE Response to Comments 47, 49, and 108.

KDHE has the discretion to waive site-specific preconstruction monitoring and allow the use of existing data if it is representative, of sufficient quality, and current. The data used by Sunflower at the direction of KDHE satisfy those criteria.

Comment 135 (GPACE Comment I.1):

Visibility Impacts. GPACE comments that just because the size of the proposed expansion is reduced does not mean that the visibility impact is necessarily reduced since emissions, stack heights, flow rates, temperatures, and meteorological conditions should be considered also.

GPACE also comments that the modeling did not include PM emissions relying on the fact that NO_x and SO_2 emissions were by far more significant and this may not be acceptable to the FLM. GPACE comments on the lack of criteria for the visibility impairment analysis; specifically related to Scott Lake and the City of Holcomb.

KDHE Response:

Refer to KDHE Response to Comment 29.

PM emissions were modeled. Table 1 in the 2007 CALPUFF summary report shows that NO_x, SO_2 and PM were all modeled, with the PM broken out into Coarse Particulate Matter, Fine Particulate Matter, and Elemental Carbon Particulate Matter, as is required to be entered for the CALPUFF model.

The Sunflower Expansion Alternative Visibility Analysis Using the CAMx Modeling System dated June 19, 2007, explains that NOx and SO2 dominate the visibility impact. Therefore, PM was not included in the CAMx modeling analysis.

The Federal Land Manager (FLM) provided no comment on the current project. The use of the 2007 analysis in lieu of a separate analysis for H2 alone was not required, and the FLM did not communicate a problem or objection.

A Class II visibility analysis was conducted for the H2 project and submitted with the Application. Section 1.3 of Part 7.0 of the application specifically addressed the local visibility impacts associated with H2. This analysis was conducted on both Scott Lake and the City of Holcomb, and the visibility impacts submitted. A PSD construction permit application must include a visibility analysis as per 40 CFR 52.21(o). EPA's DRAFT NSR Workshop Manual goes on to clarify this requirement in Chapter D, Section II.D, "Visibility Impairment Analysis." EPA clearly outlined this analysis indicating that it is to be conducted "within the area affected by applicable emissions" by stating, "[n]ote that the visibility analysis required here is distinct from the Class I area visibility analysis requirement."

EPA goes on to further indicate which modeling guidance to follow and states that while, "[it] was designed for Class I area impacts…the outlined procedures are generally applicable to other areas as well." The guidance referred to in the DRAFT NSR Workshop Manual was intended for Class I analyses, and the criteria to measure them against are for Class I areas. There is no data or guidance on Class II areas, as EPA has never stated to what degree visibility impairment is acceptable in such areas.

Comment 136 (GPACE Comment I.2):

Ozone NAAQS Secondary Standard. "The application does not provide the secondary analysis, and the permit summary only discusses the impact to vegetation in a limited way without mentioning the proposed standard. In many cases the secondary standard is more restrictive than the primary standard. The NAAQS will apply to operations as well as construction. Sunflower should review its emissions to determine if it will meet the proposed secondary standards. KDHE should analyze information from Sunflower and make its conclusions available for public review."

KDHE Response:

EPA has not issued a final revision to the proposed secondary ozone NAAQS. As a result, the permit decision need not address the proposed standard.

Comment 137 (GPACE Comment J):

Specific Comments on the Permit's Proposed Conditions. In addition to other comments, GPACE listed the following comments on specific verbiage in the draft permit on the following pages listed below. GPACE indicated these are separate items from other comments and should be addressed if this permit is to be issued.

Page 4 of Permit:

1. 40 CFR 60, Subpart IIII should be listed as an applicable requirement.

2. Sulfur should have a shorter time for demonstrating compliance. The short term modeling assumptions should be translated to % sulfur and included as no less than 30-day rolling average sulfur content.

3. "Western" coal should be defined.

Page 6 of Permit:

1. Neither the application nor the permit rationale from KDHE explains how the Sunflower project could be less than 10 tpy HAP. EPRI data indicates the facility's potential emissions exceed major source thresholds. 112(g) review should be conducted prior to the issuance of this permit.

2. PM, PM_{10}, and $PM_{2.5}$ emissions need to be defined more clearly. PM, as determined with Method 5, will capture PM_{10} as well.

Page 7 of Permit:

1. Boiler NO_X limits: Although start up and shut down emissions are discussed and an hourly emission limit is assigned, there is no real limit on startup – a start up event could go on indefinitely. Start up limits should be established limiting the time of start up to a discrete period.

2. Cooling Tower: Cooling tower emissions are a function of recirculation rate, drift eliminator design, and total dissolved solids in the circulating water. The proposed permit condition does not include limits on the volume of recirculating water.

Page 9 of Permit:

1. PM emission limits: KDHE indicates the boiler will be using a continuous monitoring system for PM on page XX. Demonstration of compliance with the established BACT should be based on continuous monitoring data rather than on shorter term stack testing.
   - One of the purposes of construction permitting is to establish BACT. 0.018 to 0.025 lb/MMBTU total PM_{10} and $PM_{2.5}$ emission factors are significantly different. The permit should identify expected emissions. If testing indicates noncompliance with

those limits then the facility should be deemed out of compliance. Any changes to the construction permit – not just those related to BACT for particulate matter – should be subject to public review and comment.

- Particulate matter emissions during start up and shut down of the boiler are not limited in this draft permit. There is no limitation on operating without fabric filters. There is no limit on the total length of start up.

Page 11 of Permit:

1. SO_2 inlet should be limited with a shorter time period. XXX recommends 30 day rolling averages rather than annual averages.

2. Permit Conditions #1: GPACE has previously identified in these comments its concern regarding the SO_2 inlet emission limit of 1.23 lb/MMBtu. Is HEP going to have a CEMs at the inlet to the scrubber?

KDHE Response:

Page 4 of Permit:

1. *The above mentioned NSPS has been adopted in Kansas regulation K.A.R. 28-19-720 and is included in the final permit.*

2. *Please refer to KDHE Response to Comments 15 and 42. There are now action levels in the Permit Conditions, Monitoring and Reporting portions of the permit.*

   A permit condition has been added to address 1-hour SO_2 emissions. If the total SO_2 emissions from H2 exceed 4089 lb/hour during any 1-hour period, the facility is required to notify KDHE, and could be required to conduct an air dispersion modeling analysis.

3. *The final permit specifies the fuel for H2 as Powder River Basin (PRB) sub-bituminous coal or other western coal. No further description is necessary since the final permit includes various emission limits that have to be met by the facility.*

Page 6 of Permit

1. *Refer to KDHE Response to Comment 52.*

   The application of SO_2 and particulate matter BACT control technology on H2 also reduces the level of emissions of HAPs. Based upon testing on the similarly-equipped H1 source, there is no potential that H2, controls considered, will emit any single HAP in an amount equal to or greater than 10 tons annually, and there is no potential that H2, controls considered, will emit HAPs in any combination in an amount equal to or greater than 25 tons annually. Compliance with the HAPs requirements in this permit will verify H2 is not a major source of HAPs. Sunflower provided information in Appendix L in the

updated Application materials, to show potential to emit (post permit) from H2 is below major source thresholds for HAPs.

2. *The term "PM" has been clearly explained in the permit to mean that particulate matter (existing as solid) emitted by a steam generator that can be quantified by analysis using USEPA-approved Reference Method 5.*

   The term "PM_{10}" as used in the permit means that particulate matter (existing as solid, liquid, and gaseous form) emitted by a steam generator that can be quantified by analysis using EPA Reference Methods 5 and 202 or by Methods 201A and 202 or by Other Test Method (OTM) 27 (with cyclone sizing devices appropriate for the quantification of PM_{10}) and /OTM28 or other such USEPA-approved methods.

   The term "$PM_{2.5}$" as used in the permit means that particulate matter (existing as solid, liquid, and gaseous form) emitted by a steam generator that can be quantified by analysis using EPA Reference Methods 5 and 202 or by Methods 201 (or 201A) and 202 or by Other Test Method (OTM) 27 (with appropriate cyclone sizing devices appropriate for the quantification of $PM_{2.5}$) and OTM28 or other such USEPA-approved methods.

<u>Page 7 of Permit</u>:

1. *Refer to Comment 40.*

   H2 is designed as a base load facility and, as such, startup and shutdown of H2 should be infrequent. For baseload units, there is no requirement to limit hours of startup and shutdown. Limiting hours of startup and shutdown is not feasible. The end of startup and the beginning of shutdown are dependent on control device temperature, rather than on the time it takes to complete the process. The time it takes for the inlet to the control device to reach the temperature required to initiate or terminate control device operations depends on how long the unit has been shut down.

2. *The permit includes the following language for the cooling tower:*

   > *The cooling tower for Holcomb 2 shall be equipped with commercially available high efficiency drift eliminators with a maximum total liquid drift not to exceed 0.0005 percent of circulating water flow rate. Compliance with this requirement is demonstrated by maintaining records of the vendor-guaranteed maximum total liquid drift. No chromium-based water treatment chemicals will be used in the circulating water system and thus the requirements of 40 CFR Part 63, Subpart Q shall not apply.*
   >
   > *PM/PM_{10} emissions from each cooling tower shall not exceed 6.83 lb/hour. Total dissolved solids (TDS) in the circulating water shall not exceed 9,000 ppm by volume. The method of demonstrating compliance with the PM emission limit is limiting the TDS content of the cooling water.*

$PM_{2.5}$ emissions from the cooling tower shall not exceed 4.1 lb/hour. Total dissolved solids (TDS) in the circulating water shall not exceed 9,000 ppm by volume. The method of demonstrating compliance with the PM emission limit is limiting the TDS content of the cooling water.

The volume of recirculating water is based on the design of the unit and is not expected to vary significantly. Therefore, the permit conditions outlined above limit the emissions such that additional permit conditions are not required.

<u>Page 9 of Permit</u>:

Please refer to KDHE Response to Comments 132, 59 and 67. PM emissions are limited on a 30-day rolling average basis, and include startup and shutdown.

Limiting hours of startup and shutdown is not feasible. The end of startup and the beginning of shutdown are dependent on control device temperature, rather than on the time it takes to complete the process. The time it takes for the inlet to the control device to reach the temperature required to initiate or terminate control device operations depends on how long the unit has been shut down.

<u>Page 11 of Permit</u>:

1. *Please refer to Section III.A. The CAA does not require KDHE to implement the new regulatory requirements (1 hour SO_2 NAAQS) contained in this comment.*

   Language has been added to the permit to address short term emission concerns. If the total SO_2 emissions from H2 exceed 4089 lb/hour during any 1-hour period, the facility is required to notify KDHE, and could be required to conduct an air dispersion modeling analysis.

   Emission estimates used for the purposes of the permit in air quality dispersion modeling and other requirements are representative of maximum expected emission rates for time periods applicable to meet regulatory requirements and protect the NAAQS. Therefore, additional permit limits are not needed.

2. Yes, H2 will have a CEM at the inlet to the scrubber.

Comment 138 (GPACE Comment K):

Start Up and Shut Down Emissions. Although the Draft Permit and Summary loosely address start up and shut down operations, the Permit has no limitation on the time the HEP project can spend in startup.
The varying startup and shutdown periods are confusing and complicated. At the main boiler, there would be at least three different time periods for startup every time the unit began operations. The application and draft permit have varying definitions based on control device

temperature and pollutant. What other options did KDHE consider for defining these periods?
The permit should be written so that it is easy for the regulatory agencies and the public to assess compliance with emission limits – both under normal operations and while in SUSD. Currently, the limits have very long demonstration periods.
The draft permit and permit summary identify "Good Combustion Practices" as BACT for SUSD. However, recent PSD permits have selected specific requirements for SUSD. KDHE should establish numeric limits for startup/shutdown periods for VOC, PM_{10}, $PM_{2.5}$, SO_2, and NO_2 and provide rationale for same.

KDHE Response:

Refer to KDHE Response to Comments 7 and 40.

Comment 138 (GPACE Comment K):

Start Up and Shut Down Emissions. Although the Draft Permit and Summary loosely address start up and shut down operations, the Permit has no limitation on the time the HEP project can spend in startup.
The varying startup and shutdown periods are confusing and complicated. At the main boiler, there would be at least three different time periods for startup every time the unit began operations. The application and draft permit have varying definitions based on control device temperature and pollutant. What other options did KDHE consider for defining these periods?
The permit should be written so that it is easy for the regulatory agencies and the public to assess compliance with emission limits – both under normal operations and while in SUSD. Currently, the limits have very long demonstration periods.
The draft permit and permit summary identify "Good Combustion Practices" as BACT for SUSD. However, recent PSD permits have selected specific requirements for SUSD. KDHE should establish numeric limits for startup/shutdown periods for VOC, PM_{10}, $PM_{2.5}$, SO_2, and NO_2 and provide rationale for same.

KDHE Response:

Refer to KDHE Response to Comments 7, 40, 61, 62, 65, and 67.

Considerations of BACT options for startup and shutdown periods are discussed in Part 4.0 of the permit application.

Clarifying language has been added to the permit that states: each emission limitation established or referenced in this permit applies to the respective emission source subject to that limitation at all times, including startup, shutdown, and malfunction, unless the applicability of that limitation is expressly excluded under certain conditions as to which a different limitation is applicable under a specific provision of the permit.

Comment 139 (GPACE Comment L):

Rulemaking Process Which Will Affect the HEP. The EPA rulemaking gateway identifies the following rules in various stages of development. These rules are certainly important for KDHE and the public to consider as the decision to permit this facility is weighed.

The EPA rulemaking gateway identifies the following rules in various stages of development. These rules are certainly important for KDHE and the public to consider as the decision to permit this facility is weighed.

- Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Proposed Rule Making, July 2012)
- National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers (Final Rule, December 2010)
- National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-fired Electric Utility Steam Generating Units (Proposed Rule Making, March 2011)
- National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial & Institutional Boilers and Process Heaters (Final Rule, December 2010)
- New Source Performance Standards for Electric Utility and Industrial-Commercial-Institutional Steam Generating Units (Proposed Rule Making, March 2011)
- Prevention of Significant Deterioration for PM2.5 - Increments, Significant Impact Levels and Significant Monitoring Concentrations (Final Rule, September 2010)
- Prevention of Significant Deterioration/Title V Greenhouse Gas Tailoring Rule (Final Rule Issued; effective January 2, 2011)
- Review of the National Ambient Air Quality Standards for Carbon Monoxide (Proposed Rule Making, November 2010)
- Review of the National Ambient Air Quality Standards for Lead (Proposed Rulemaking December 2013)
- Review of the National Ambient Air Quality Standards for Ozone (Proposed Rule Making, January 2010, Final November 2010)
- Review of the National Ambient Air Quality Standards for Particulate Matter (Proposed Rule Making, February 2011)
- Review of the National Ambient Air Quality Standards for Sulfur Dioxide (final, June 22, 2010)
- Review of the Secondary National Ambient Air Quality Standards for Oxides of Nitrogen and Oxides of Sulfur (proposed rule making, July 2011)
- Revision to Pb Ambient Air Monitoring Requirements (final rule, November 2010)
- Standards for the Management of Coal Combustion Residuals Generated by Commercial Electric Power Producers (Proposed Rule Making, June 2010; Extended Public Comment Period closed November 2010)
- Transport Rule (CAIR Replacement Rule) (Proposed Rule Making, July 2010)
- National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (Final March 2010 for compression ignition; Final rule expected August 2010 for Reciprocating Engines)
- National Emission Standards for Hazardous Air Pollutants for Compression Ignition Combustion Engines

KDHE Response:

KDHE has addressed all applicable legal requirements in accordance with all current statutory and regulatory requirements. Future changes in requirements applicable to Holcomb 2 will be applied to Sunflower as required under state and federal laws and regulations. Once the affected unit commences operation, any new applicable requirements will be incorporated into the Class I Operating Permit.

F. COMMENTS FROM CLIMATE AND ENERGY PROJECT (CEP) (Comments 140-145)

Comment 140 (CEP Comment Coal Power: Regulatory and Political Landscape – 1):

Endangerment Finding. KDHE must require Sunflower Electric to model energy efficiency and natural gas in Best Available Control Technology (BACT) analyses that take into account the impact of greenhouse gas emissions, and carry out a Maximum Available Control Technology (MACT) analysis as well. In 2009, EPA issued an endangerment finding regarding GHGs. This finding is consistent with Secretary Bremby's original reasoning in denying the initial air permit. Ignoring the finding may jeopardize the Kansas State Implementation Plan under the Clean Air Act and draw EPA's direct regulation of all air permits in Kansas.

KDHE Response:

Please refer to KDHE Response to Comment 39 for discussion of natural gas as BACT.

EPA issued an endangerment finding that serves as a basis to develop regulations. EPA issued the Tailoring Rule on May 13, 2010, which will require BACT requirements for GHGs in the PSD permitting process for stationary sources beginning January 2, 2011, contemporaneous with the date GHG regulations for mobile sources become enforceable. Until then, BACT for GHGs is not applicable. Please refer to KDHE Responses to Comments D, I and Comment 37.

The national emission standards for hazardous air pollutants (NESHAPs), established by the EPA are commonly called maximum achievable control technology (MACT) standards. MACT standards are designed to reduce HAP emissions to a maximum achievable degree, taking into consideration the cost of reductions and other factors. GHGs are not regulated under the MACT standards.

Kansas is not ignoring the impacts of the endangerment finding. Kansas has adopted administrative regulations to implement the federal GHG tailoring rule and has drafted a State Implementation Plan amendment to incorporate the permitting requirements into the Kansas air program. The SIP has been submitted to EPA for review and approval.

Comment 141 (CEP Comment Coal Power: Regulatory and Political Landscape – 2):

Regulatory. KDHE must conduct a comprehensive regulatory review inventorying and assessing all federal emissions and pollution regulations underway and pending that might possibly affect the proposed plant.

KDHE Response:

The KDHE – BOA conducts a comprehensive regulatory review as part of the permit process to ensure the permit is in compliance with all regulations which are in effect at the time of permit issuance. This review of all applicable laws and regulations is part of the permit process to ensure a federally and state enforceable permit. All required emission limitations and regulations are cited in the permit.

Please refer to KDHE Responses to Public Comments G, I, L and Comments 5, 37, and 39.

Comment 142 (CEP Comment Coal Power: Regulatory and Political Landscape – 3):

Legislative. Conduct a comprehensive review of the cap and trade legislation that recently passed the House, model how it would affect the proposed coal plant, incorporate that into the economic assessments of the project, and additionally review any energy legislation introduced between October 2010 and January 2011.

KDHE Response:

KDHE keeps current with all legislation which has the potential to impact the air permitting process. If cap and trade legislation becomes law KDHE will review any impacts this may have on the air permitting process. As part of the legislative process, economic assessments are conducted to look at the overall cost versus benefits if the bills were enacted into law, however, economic assessments of proposed legislation are beyond the scope of the air permitting process.

Comment 143 (CEP Comment Coal Power: Regulatory and Political Landscape – 4):

Judicial. Conduct a comprehensive review of the potential legal complications that would ensue from issuing including but not limited to EPA intervention and lawsuits from private organizations.

KDHE Response:

There is no legal requirement and KDHE does not have the authority to conduct this type of review. KDHE's responsibility is to consider the permit application and draft a permit in compliance with applicable laws and regulations

Please Refer to KDHE Response to Comment D.

Comment 144 (CEP Comment Coal Power: Regulatory and Political Landscape – 5):

Impact to Kansas Taxpayers. Develop a fiscal note regarding the costs of comments 141, 142 and 143 (CEP comments 2, 3, and 4) estimating the potential costs to Kansas taxpayers of these regulatory, legislative, and judicial complications, in the event that the permit is issued.

KDHE Response:

This requirement is beyond the scope of the air permitting process.

Please refer to KDHE Response to Comment D.

Comment 145 (CEP Comment Coal Power: Economics and Fuel Supply – 1):

Call in Additional Expertise. KDHE should involve additional Kansas government agencies with the relevant expertise to evaluate Section 1.3.4 through 1.3.8 of the Sunflower Electric Holcomb Station Expansion PSD Permit Application. The Kansas legislature has not charged KDHE staff with the mission of evaluating reliability, energy supply and economic need for electrical generation, as discussed in these sections of Sunflower's application. Alternatively, KDHE must make its decision independent of these sections of the permit.

KDHE Response:

This requirement is beyond the scope of the air permitting process.

Comment 146 (CEP Comment Coal Power: Economics and Fuel Supply – 2):

Comparative Costs and Benefits of Energy Alternatives. In the additional analysis, KDHE and other agencies must make a comparative evaluation of the economic and environmental costs and benefits of energy efficiency, Class 4 and 5 wind, natural gas, supercritical coal, and nuclear power.

a. The environmental costs must include impacts on public health, water resources, agricultural production of crops and livestock, habitat for hunting and fishing, and recreation.
b. The economic costs must include capital costs of constructing these generation resources, as well as the impacts of a $0 carbon tax, $20 carbon tax, and $50 carbon tax.
c. Any consideration of the costs and benefits of transmission lines from the Sunflower project must now include the benefits conferred by two other extra high voltage lines now already approved and underway in Kansas – the 345 kV line from Spearville, KS to Axtell, NE, and the 345 kV double circuit line from Spearville to Wichita.

KDHE Response:

KDHE conducted the required evaluation of this air permit application. Please refer to KDHE Response to Comment D. The applicable environmental costs are addressed by the

federal Clean Air Act, the Kansas Air Quality Act, and the federal and state regulations implementing those statutes. The federal and state air laws address these issues through statutory and regulatory provisions by means of setting of air quality standards, air pollutant emissions control technology requirements, air pollutant emissions limitations, etc., as part of the national and state air programs to protect ambient air quality. Public health is taken into account as it relates to air quality.

Water resources are regulated by the Kansas Department of Agriculture. Please refer to KDHE Response to Comment C. The role of KDHE in the PSD permit review process is to evaluate Sunflower's Application in accordance with applicable provisions of existing law. A comparative evaluation regarding energy efficiency, Class 4 and 5 wind, natural gas, supercritical coal and nuclear power or transmission line benefits is beyond the scope of the air permitting process.

Comment 147 (CEP Comment Coal Power: Economics and Fuel Supply – 3):

Refer to Existing Generation Predictions**.** The additional analysis must compare the Sunflower Electric permit application's statement of need with the projections and analysis contained in Kansas Electric Generation Tables prepared by the Kansas Energy Council, "Summary of Existing Power Plants" and "Capacity and Peak Load, 2008-2028.

KDHE Response:

This requirement is beyond the scope of the air permitting process. Please refer to KDHE Response to Comment D.

Comment 148 (CEP Comment Coal: Environmental Impact and Greenhouse Gas Emissions – 1):

Evaluate Climate Change Impacts of Greenhouse Gas Emissions. As required by Kansas law, KDHE must take into account the EPA's endangerment finding on greenhouse gases. Therefore, Sunflower must consider how the plant's greenhouse gas emissions in the atmosphere impact the public health and welfare of current and future generations, in Section 7: Additional Impacts, of the permit application. At a minimum, this consideration must include:

a. The impact of projected climate change scenarios on water availability, soil moisture, average temperature, and climate variability; and

b. The impact of projected climate change on the Kansas agriculture and livestock industries, wildlife and natural habitats, impacts on hunting, fishing, and recreation.

KDHE Response:

Please refer to KDHE Response to Comment 140.

Comment 149 (CEP Comment Coal: Environmental Impact and Greenhouse Gas Emissions – 2):

Carbon budget of Kansas. KDHE must update the most recent draft of the Kansas Greenhouse Gas Inventory and Reference Case Projection, created in the course of the Kansas Energy and Environmental Policy (KEEP) advisory group, to include the affects of the proposed coal plant on the total carbon emissions and sinks of Kansas.

KDHE Response:

KDHE does not have the authority to update this draft of the Kansas Greenhouse Gas Inventory and Reference Case Projection as part of this permit review. In response to the FY2008 Consolidated Appropriations Act (H.R. 2764; Public Law 110–161), EPA has issued 40 CFR Part 98, which requires reporting of GHG emissions from large sources and suppliers in the United States. Part 98 is intended to collect accurate and timely emissions data to allow for informed policy decisions. Suppliers of fossil fuels or industrial GHGs, manufacturers of vehicles and engines, and facilities that emit 25,000 metric tons or more per year of GHG emissions are required to submit annual reports to EPA. Part 98 was published in the Federal Register *(www.regulations.gov) on October 30, 2009 under Docket ID No. EPA-HQ-OAR-2008-0508-2278. Part 98 became effective December 29, 2009.*

EPA's GHG reporting system will provide a better understanding of where GHGs are generated and will guide development of sound policies and programs to reduce emissions.

G. COMMENTS FROM CHESAPEAKE ENERGY CORPORATION (Comments 150-158)

Comment 150:

Combustion of natural gas emits significantly less greenhouse gas, particulate matter, hazardous air pollutants, mercury and lead than does the combustion of coal.

KDHE Response:

Please refer to KDHE Responses to Comment I, 37, and 39.

The comment addresses Sunflower's basic technology selection. KDHE lacks statutory or regulatory authority to redefine the source that Sunflower seeks to permit. A supercritical pulverized coal-fired steam generator was chosen as the design for H2 to meet the needs of the project. The decision to propose construction of a supercritical pulverized coal-fired steam generator as opposed to a simple or combined cycle natural gas unit is addressed in Section 1.3.9 of Sunflower's Application, as follows:

> *The long-term fuel cost associated with such resources makes energy supplied by them too expensive for the base-load needs of the Participants. These generation*

resources are more suitable for peaking and intermediate load applications, and Sunflower already operates more than 600 MW of this type resource to meet the peaking and intermediate load requirements of its owners.

KDHE has applied all existing federal and state regulations regarding control of particulate matter, hazardous air pollutants, mercury, and lead and incorporated the applicable requirements into the permit.

Comment 151:

EPA and Departments of Environmental Quality throughout the nation are beginning to consider natural gas as a Best Available Control Technology for new electricity generation and as a Best Available Retrofit Technology as an alternative to controls on existing coal-fired electricity generating units.

KDHE Response:

Please refer to KDHE Response to Comment 39 for the BACT process.

The review of Best Available Retrofit Technology is not required as part of this PSD permitting process.

Comment 152:

Utilities across the country are beginning to retire their coal fleets and look at alternatives to coal for new generation because of environmental, health and financial considerations.

KDHE Response:

Decisions to retire coal-fired units by utilities are made based on factors that are unique to each unit. These include age, condition, existing pollution controls, access to power from other sources, applicable regulations, and business decisions. Decisions by other utilities have no legal bearing on KDHE's review of Sunflower's Application. Decisions to retire units are also based on whether and how new construction is regulated in each state. The ability to receive cost recovery for a new unit can be a decisive factor in a decision to retire an existing unit. Such decisions are not made by KDHE in Kansas. The Kansas Corporation Commission has authority over rate recovery decisions in Kansas.

Comment 153:

The states of Colorado and Oklahoma are in the process of revising their respective SIPs for Regional Haze and there is evidence that emissions from the existing Holcomb facility impact the Great Sand Dunes National Park in Colorado and the Wichita Mountains Wildlife Refuge in Oklahoma, both of which are Class I areas. An additional 895 MWs at this site could exacerbate the impact.

KDHE Response:

Please refer to KDHE Responses to Comments 28 and 29.

KDHE air planning staff has had discussions with air program staff in both Colorado and Oklahoma regarding visibility impacts from existing sources and potential sources in Kansas. We have no reason to believe that either Colorado or Oklahoma will submit a Section 126 request to EPA regarding Kansas sources in the future. If the Sunflower H2 plant is constructed, KDHE will incorporate emissions from the plant into the emissions inventory and modeling work that will be conducted for the second ten-year cycle of the regional haze process.

Comment 154:

EPA is in the process of considering significant rulemakings that will impact the Holcomb Expansion, the most stringent of which will become effective on January 2, 2011.

KDHE Response:

Please refer to KDHE Responses to Comments I, 37, and 139.

Comment 155:

Not only is natural gas better for the environment of Kansas and the region, there is an abundance of this cleaner burning fuel in the United States as well as in Kansas. Natural gas serves as an environmental and economic driver to the citizens of Kansas, unlike sub-bituminous coal from Wyoming.

KDHE Response:

Please refer to KDHE Response to Comment 150 regarding Sunflower's basic technology selection. Please refer to KDHE Response to Comment 39 regarding the use of coal instead of natural gas at the proposed H2 unit. In regard to natural gas serving as an economic driver to the citizens of Kansas, the federal and Kansas statutes and regulations regarding permitting air pollution sources do not provide for regional economic factors to be included in the decision-making process.

Comment 156:

Kansas should consider diversifying the way in which power is generated in the state; approximately 73% of the total generation in Kansas is from coal-fired generating units while only 5% is derived from natural gas. With reasonably foreseeable environmental regulations, additional coal fired generation is just too risky.

KDHE Response:

Please refer to KDHE Response to Comment 39.

The diversification of electric power generation in Kansas is not an issue that is covered by the statutory or regulatory authority of KDHE. The Kansas Legislature addressed this issue in passage of H.B. 2369 which includes provisions for renewable energy.

Comment 157:

Combined cycle natural gas units are faster and less expensive to build than super-critical coal units and these cost advantages would lead to a more competitive economic climate for Kansas' utility customers and businesses.

KDHE Response:

Please refer to KDHE Response to Comment 155.

H. COMMENTS FROM CLEAN ENERGY ACTION (Comments 158-160)

Comment 158 (Clean Energy Action (CEA) 1):

An analysis of coal characteristics of various coal mines in the Powder River Basin (PRB). It is clear that the existing H1 is buying coal from a number of different PRB mines and since different mines produce coal with different qualities, KDHE needs to consider the breadth of coal qualities that might be supplying the proposed new H2. A summary of existing Sunflower coal purchases in 2010 compiled from Energy Administration (EIA) 423 reports were provided by commenter.

KDHE Response:

Please refer to KDHE Response to Comments G, 9,11, and 118 regarding coal quality and related permit issues.

Comment 159 (CEA2):

An analysis of life expectancy of the existing coal mines in the PRB and the geologic, economic, legal and transportation constraints that are likely to be faced in the future. There is no need to proceed with a coal plant until at least the following questions have been answered:

a) What is the existing life span of the mines presently supplying the Sunflower Holcomb plant?

b) What is the status of future plans for expansion and how long will those expansions extend the life span of the PRB mines that are expected to supply the sunflower Holcomb plant?

c) What economic impact is likely to be felt from increasing overburden in the proposed mine expansions?
d) What economic impact is likely to be felt from the need to reclaim the coal mines in the PRB?

KDHE Response:

Please refer to KDHE Response to Comment D.

The review of the life span of coal mines, potential mine expansions, and related economic impacts is not required as part of the PSD permitting process.

Comment 160 (CEA 3):

What will be the impact on Sunflower Holcomb proposed coal plant if it burns Kansas coal instead of Wyoming coal?

KDHE Response:

Please refer to KDHE Response to Comment 107.

I. COMMENTS FROM KANSAS SIERRA CLUB (Comments 161-167)

Comment 161:

It is unlikely that Sunflower would pursue the project without Tri-State, since Tri-State would own 695 MW of power. In June and July of this year, Tri-State conducted a series of public meetings to determine their long-term needs. Of the 15 scenarios demonstrate a need for new coal capacity, and this one assumes no costs on carbon. It shows a need of 302 MW of new coal capacity by 2026 and not an immediate need for 695 MW. KDHE should request that Tri-State document there is a near-term need for the energy that would be generated by this coal plant, which was not demonstrated by Tri-State's recent resource planning process.

KDHE Response:

Please refer to KDHE Response to Comments 31 and 32.

There are no provisions within State or Federal law that prohibits an entity from applying for a PSD permit. Whether or not the capacity for the electricity is needed from the proposed plant plays no role in the determination of the facility's compliance with the current laws and regulations that govern air quality. Therefore, KDHE has no jurisdiction in the matter of need for capacity from the Holcomb facility.

Comment 162:

KDHE should request that Tri-State document that there are concrete plans in place to move forward with construction of HII if a permit were to be issued. If KDHE is unable to get this information from Tri-State, we need to cease further misuse of KDHE's time on this permit. The permit should not be considered until there is substantial evidence that the project is needed and that the developers have legitimate plans to construct it.

KDHE Response:

Please refer to KDHE Response to Comments 31 and 32.

There are no provisions within State or Federal law that require an entity to provide additional evidence of plans to construct a project, other that the information required to be submitted as part of the PSD permit application.

Comment 163:

Did the Visibility Impacts study with Federal Land Managers include any discussion of impacts on Class II areas of significance, such as the key wetland areas /actually downwind /of the Holcomb Plant? What impacts are predicted by the modeling on these fragile wetlands and their wildlife, particularly as global climate change affects future precipitation and evaporation rates?

Neither the Great Sands Dune National Monument (GSDNM) in Colorado nor the Wichita Mountains NWR in Oklahoma is located downwind of the facility, as are Cheyenne Bottoms and Quivira NWR**.**

One of the express purposes of the PSD program of the Clean Air Act is "to preserve, protect, and enhance the air quality in national parks, national wilderness areas, national monuments, national seashores, and other areas of special natural, recreational, scenic, or historic value." The PSD title contains measures that can protect Class II areas. These Class II floor areas include the following areas: national monuments, national primitive areas, national preserves, national recreation areas, national wild and scenic rivers, national wildlife refuges, national lakeshores and seashores.

KDHE Response:

Please refer to Section III.D.1 and KDHE Response to Comment 135.

Federal Land Managers (FLMs) evaluate only visibility impacts as they relate to Federal Class I areas and none was requested by an FLM. Sunflower did conduct a visibility analysis at Scott Lake State Park, which is downwind and approximately 50 miles from Holcomb Station. This was the Class II area for visibility evaluation identified by KDHE and EPA. The analysis for this Class II area was performed using VISCREEN and the visibility impacts at Scott Lake were determined to be acceptable. The PSD Class II visibility impact

analysis required by the regulations does not assess impacts on wetlands and wildlife. Sunflower did perform a soils and vegetation impact analysis. . That analysis shows impacts to soils and vegetation to be acceptable.

Although the Great Sand Dunes National Park (Great Sand Dunes) is not generally downwind of Holcomb, it is the closest Class I area that may be downwind of Holcomb Station on certain days. Therefore, Great Sand Dunes was the target of analysis first determined by Sunflower's consultant as satisfying the regulatory requirement. It is also the closest Federal Class I area (approximately 400 kilometers from the proposed plant).

The FLM responsible for the Wichita Mountain National Wildlife Refuge (Wichita Mountain) Class I area subsequently identified that Class I area for evaluation. It is the next closest Class I area. Sunflower performed additional Class I modeling that included the Wichita Mountain, which is located SSE of Holcomb Station and is frequently downwind of the H1 stack plume, especially in winter months.

Neither Cheyenne Bottoms nor Quivira National Wildlife Refuge (Quivira) are Class I areas, so no visibility analysis for those locations was required under the regulations. The visibility analysis for Scott Lake, which is substantially closer and more frequently downwind of Holcomb Station than either Cheyenne Bottoms or Quivira was evaluated.

Comment 164:

What are the long range effects of the air emissions (VOCs, NO_x, ozone) of an expanded Holcomb Power Plant on the ozone levels in areas of Kansas already struggling to meet the recently established lower ozone standards? What will be the human health impacts? What are the potential economic impacts on the economy of the KC Metro area if regaining attainment standards is made more difficult or lengthier? How do mobile sources associated with the facility, and not included with the modeling, contribute to the production of ozone and ozone precursors?

The Kansas City Metro area is expected to be formally designated non-attainment for ozone next year. Several years ago, during development of a Clean Air Action Plan for the region, modeling done at that time indicated that as much as 1/3 of the ozone measured in the KC area was transported into the region. Even a small increase in the amount of ozone precursors from upwind sources might have a significant effect on the number of days of ozone exceedances here. The impacts on human health and the local economy could be large. Citizens in the regions are already involved in "voluntary" ozone reduction education and action. If construction of the Holcomb expansion offsets these voluntary measures, then there will be no incentive for citizens to change their behaviors as a key step towards regaining attainment status

KDHE Response:

PSD requirements do not include ozone modeling to be performed for a single source. Ozone is not directly emitted by power plants, such as Holcomb, but is formed in the

atmosphere from the emission of NO_x and VOCs from both anthropogenic and natural sources under certain conditions.

A qualitative analysis of the impact that emissions from the Expansion Project might have on ozone levels was conducted. That analysis demonstrates that the project will not cause or contribute to an exceedance of the current ozone standard. Maximum potential emissions from H2 would represent less than 1% of statewide NO_x emissions in 2012, according to EPA projections in its proposed Transport Rule (see Federal Register, Aug. 2, 2010). The primary source regions for ozone impact in Kansas City are southeast, south, and southwest of the metropolitan area, and do not include Holcomb Station.

Impacts on human health from sources of criteria pollutants are the driving force behind the establishment and refinement of NAAQS. EPA establishes the NAAQS and the methods by which the emissions from a specific source are determined to cause or contribute to an exceedance of a NAAQS. Emissions from H2 were found not to cause or contribute to a modeled exceedance of the NAAQS and thus not to have a significant impact on human health as determined by EPA. These impacts have been appropriately evaluated for all criteria pollutants emitted by the source.

H2 will not have significant impacts on the ozone levels in the Kansas City airshed. The presence, or absence, of H2 will have little impact on the long-term compliance plans for the Greater Kansas City Metropolitan Statistical area (MSA).

EPA regulations exclude direct emissions from mobile sources such as vehicles from the ambient air impact evaluation required for the issuance of a PSD construction permit for a stationary source and were not included.

The air quality modeling exercises conducted by Sunflower show there will be no significant ozone impacts at the receptors monitored in the Greater Kansas City MSA area attributable to H2.

Comment 165

Are the BACTs for VOCs and CO meaningful and enforceable? What is a "good burn practice" and how is it monitored? Are there more stringent BACTs for VOCs and CO which could be applied to this permit? At the hearing today (Aug. 2) in Overland Park, it was stated that the BACTs for VOCs and CO were "good burn practices." This implies that the BACT is determined by the operator, without additional technology or metrics for monitoring. Given that VOCs are precursors for ozone and can contain toxic gases, I would support permit conditions beyond "good burn practices."

KDHE Response:

BACT for VOCs and CO includes numeric emission limitations that are enforceable through stack testing and continuous emission monitoring. A CO CEMS will be used to continuously monitor CO emissions and demonstrate compliance with the CO limit. The CO CEMS will

also be used as a surrogate for assuring continuous compliance with the VOC limit since both CO and VOC emissions, as byproducts of incomplete combustion, are directly related to the level of combustion achieved. Compliance with the VOC limit will be demonstrated by stack testing.

There are no feasible add-on control technologies that can be applied to coal-burning sources. Because CO and VOC emissions are the product of incomplete combustion, the CO and VOC BACT emissions limitations will be achieved through good combustion practices to minimize their production.

Comment 166

A pair of new studies, one in the United States, another in Germany, report strong evidence that diabetes rates climb with increasing air pollution in the form of tiny airborne particles. If this linkage proves true, it would be of immense importance to protecting the air quality of Kansas, especially in low income/minority communities already suffering from high rates of diabetes. Holcomb is home to many Latino immigrants working in the meat-packing industries in the area. Until studies are completed on the diabetes issue, this is a health risk we can't afford. In this light, KDHE should re-examine the actual need for expansion of a particulate emitting coal-fired plant and deny the permit if Tri-State cannot demonstrate they will construct the plant within the required 18 month time frame. If they document they can construct, then KDHE should require cleaner energy alternatives be considered.

KDHE Response:

Please refer to KDHE Response to Public Comments F, 30, 31, 34, and 39.

Comment 167:

Tri-State has contracted to receive almost 80% of the plant's output. In recent regulatory proceedings, Tri-State demonstrated that they are no longer seriously considering proceeding with the Holcomb 2 project. Tri-State has prepared a complete draft of their Electric Resource Plan that will be submitted to the Colorado Public Utilities Commission. Tri-State has not identified a capacity need for the next 6 years." Holcomb 2 is mentioned on page 12 under "Resource Planning Process," as still a "potential option," however they clearly have no intention of actually exercising that option, because it would not be in the interests of their member coops and ratepayers. It would be illegal for KDHE to issue the subject permit because it would allow Sunflower to lock in inferior pollution controls. H2 will emit some 339 million tons of CO2 over the 50-year life of the plant.

KDHE Response:

Please refer to KDHE Response to Comments I, 30, 31, and 32.

J. COMMENTS FROM K. TRAN, AMI ENVIRONMENTAL (AMI) - PREPARED FOR KANSAS SIERRA CLUB) (Comments 168-172)

Comment 168:

Ozone-Requirements for Long-Range Modeling**.** The Air Quality Impact Analysis for ozone significantly underestimates the actual impact of the project.

KDHE Response:

Please refer to KDHE Response to Comment 164.

Comment 169: CAMx, Ozone Impacts. CAMx modeling confirms that Sunflower substantially underestimates the proposed project's impact on ground-level ozone at the Trego County monitor and throughout Kansas. There is an increase over the baseline ozone levels for the Goodland Monitor.

KDHE Response:

Please refer to KDHE Response to Comment 48.

Comment 170

CAMx – Conclusion for Ozone. The proposed expansion will cause a maximum increase of 5.8 ppb ozone in SW Kansas, and an increase of 1.65 ppb ozone at the Goodland monitor. It exacerbates existing violations of the 2008 ozone NAAQS and will cause two exceedances of the newly proposed NAAQS of 70 ppb.

KDHE Response:

Please refer to KDHE Response to Comment 48. There are no monitored violations of the current 75 ppb ozone NAAQS in western Kansas at the Trego County monitor. The Goodland monitoring site was a temporary site operated for two years in the early 1990's. No current or relevant ozone monitoring data for Goodland exists. The CAMx modeling performed by the commenter does not predict violations of the current ozone standard.

The AMI Environmental model relied upon by Sierra Club uses a relatively large grid spacing (36 km) for the CAMx runs. Near-field modeling predictions (i.e., at 25 km) will not be accurate with such a large grid spacing. In addition, because the original dataset was intended for a visibility analysis an ozone performance evaluation was never performed by KDHE or the commenter. For these reasons it is inappropriate to utilize these near-field ozone predictions.

Comment 171:

Discussion of $PM_{2.5}$ Impacts. There is an increase over the baseline $PM_{2.5}$ levels predicted at the Goodland monitor and at the Trego County monitor.

KDHE Response:

Although EPA has promulgated a Class II Significant Impact Level (SIL) for $PM_{2.5}$, this far-field evaluation is not required for a PSD construction permit.[47] *The results cited in the report show that for $PM_{2.5}$ there are no predicted violations or exceedances of the 24-hour $PM_{2.5}$ NAAQS, either at Goodland or at Trego County*[48] *attributable to H2. A determination of compliance with the NAAQS is based on the 8th high 24-hour value for $PM_{2.5}$ concentrations in each of the three-year periods for which the analysis is performed. The AMI analysis does not assess the 98th percentile (8th highest) 24-hour concentration. The analysis covers a 3-month period and reports the maximum overall concentrations. The results presented indicate that the predicted $PM_{2.5}$ levels are below the NAAQS.*

Comment 172:

Conclusion for $PM_{2.5}$. The proposed expansion is predicted to cause a maximum 24-hour $PM_{2.5}$ increase in concentration of 3 $\mu g/m^3$ in SW Kansas, such increase arising from direct emissions of $PM_{2.5}$ plus secondary atmospheric chemical conversion.

KDHE Response: *The maximum incremental 3 ug/m^3 impact on 24-hour average $PM_{2.5}$ concentration predicted by AMI modeling is less than the maximum incremental $PM_{2.5}$ concentration as modeled by Sunflower in its Application at a location closer to the source. The modeled $PM_{2.5}$ impact in the Application is conservative, represents the worst-case potential impact, and demonstrates compliance with the NAAQS. The modeling that was cited by the commenter*

K. COMMENTS FROM AMERICAN NATURAL GAS ALLIANCE (Comments 173-174)

Comment 173:

It is advisable for KDHE to consider the availability of robust supplies of natural gas in the state and the opportunities natural gas presents to produce power with low emissions of carbon dioxide and other pollutants. Natural gas emits half the CO_2 emissions of coal, 80% less nitrogen oxides and virtually no sulfur dioxide, mercury or particulate matter. Kansas is a net exporter of natural gas and there is new production coming online. There is enough gas being produced in Kansas to power this plant and there are major pipelines all around Finney

[47] Note that the 24-hour $PM_{2.5}$ NAAQS is a 98th percentile value, such that seven (7) exceedances are allowed at a single receptor/monitor during a calendar year without constituting a violation.

[48] The modeling did not evaluate the annual $PM_{2.5}$ NAAQS.

County to support new electricity generation from natural gas. The amount of coal produced in Kansas could only support 5 percent of the proposed coal facility's power production.

KDHE Response:

Please refer to KDHE Response to Comment 39.

Comment 174:

Unnecessary environmental sacrifices would be made if the permit to build the facility is granted.

KDHE Response:

Please refer to KDHE Responses to Comments F, 34, and 146.

L. COMMENTS FROM KANSAS RURAL CENTER (Comments 175-178)

Comment 175:

Commenter opposes permit due to the risks to water, soil, and foodstuffs from the mercury that will be emitted by this coal-fired unit, as well as the mercury and other toxic metals captured in the coal combustion waste from the plant. Methyl-mercury is a neurotoxin that bio-accumulates in food chains. In 2005, researchers reported a significant increase in the rates of autism associated with increases in environmentally released mercury in Texas. Mercury exposure can result in numerous neurodevelopmental issues in fetuses, infants, and children. Kansas had at least eight surface water bodies threatened and impaired by mercury deposition in 2010 under Section 303(d) of the Clean Water Act. For a state so heavily reliant on our crops, livestock and the water resources that sustain them, allowing an additional major source of mercury emissions (both by air deposition and from the disposal of coal combustion wastes) to threaten our agricultural system is absolute folly.

The 0.02 lbs/GwH rate of mercury emission allowed under this permit amounts to roughly 150 lbs per year of mercury entering our air, water, and soil. That does not account for the amount of mercury contained in coal combustions wastes from the plant, and currently stored in unregulated and potentially unsecure ways. According to the Toxic Release Inventory for mercury emissions, these additional 150 lbs would make the existing Holcomb power plant and the proposed expansion responsible for a combined 20% of mercury released in the State of Kansas. We do not want our air, water, and soil sacrificed for the benefit of a Colorado-based utility.

KDHE Response:

Please refer to Section III.C.2 and III.C.3, KDHE Responses to General Comments F and G, and Comments, 200, 203, 204, 205, 207, and 215.

Three years ago, legislation was passed to add additional mercury monitoring to Kansas' capabilities. Six ambient mercury monitors were added in Kansas which allowed the State to work with surrounding states and the federal government to give the citizens of Kansas more precise readings of mercury concentrations. These levels are constantly monitored and any substantial increases in these concentrations will be duly investigated. The Kansas Mercury Monitoring Network can be found at:

http://www.kdheks.gov/bar/air-monitor/mercury_monitoring.htm

Comment 176:

Regional Air Quality. Modeling required for these permits only considers the mobilization of pollutants into the atmosphere. The information available on Sunflower Electric Power Corporation's (Sunflower) website and the technical documents reviewed mention only the air dispersion modeling conducted to determine the impacts the unit will have on the local air quality. Critical details about where toxic emissions will go, and what happens when they get there are missing. Sunflower has modeled the first stage required to demonstrate efforts to contain its toxic emissions, but we are left with little information in the permit about the impacts on our health and our shared agricultural economy from the neuro-toxic pathway created by the Holcomb Station expansion.

Critical details about where these toxic emissions will go, and what happens when they get there are missing from the modeling. Sunflower has modeled the first stage required to demonstrate efforts to contain its toxic emissions, but we are left with little information in the permit about the impacts on our health and our shared agricultural economy from the neuro-toxic pathway created by the Holcomb Station expansion.

KDHE Response:

Please refer to Section III.B, Ambient Air Quality Analysis, KDHE Response to General Comments F and G, Comments,

The PSD permitting regulations at 40 CFR 52.21(o) require the owner or operator of any proposed new major source to provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of construction of the new source. The soils impact analysis conducted by Sunflower is contained in Part 7.0, Section 1.6 of the permit application. The modeled NOx, CO and SO_2 emissions from the proposed unit are well below the reference levels cited in the analysis for negative impacts on the soils and the types of native vegetation and crops that occur in the vicinity of the proposed unit.

The primary impacts of coal fired power plants on surface waters occur through acidification of lakes as a result of deposition of acids formed from acid gas emissions, and the deposition of mercury. The federal Acid Rain Program contained in Title IV of the Clean Air Act is the regulatory tool to address acid deposition from coal fired power plants. The proposed Unit 2 at Sunflower will be subject to the federal Acid Deposition Control provisions of the Clean Air Act.

EPA has announced intentions to propose a new utility MACT in near future that would address emissions of hazardous air pollutants (HAPs) from coal fired boilers. Sunflower will be required to comply with any final MACT rule by making the necessary physical or operational changes to the unit.

Comment 177

Did Sunflower model the rate of wet or dry deposition of mercury? Did Sunflower model the mass of mercury settled or rained out of the atmosphere? Did Sunflower determine the probability of mercury depositing on our streams and watercourses, our agricultural fields, and on our livestock? Because wherever these mercury compounds come down, they will be absorbed into our food and water supplies. Will this mercury be taken up by livestock and become part of our food chain, as is the case with fish in our impaired rivers and streams?

One of the most troubling parts of this process is the fact EPA is preparing new mercury regulations - just as it is for carbon dioxide, ground level ozone and ozone precursor emissions, and sulfur dioxide. EPA will develop new mercury emissions standards for coal- and oil-fired power plants under the Clean Air Act Section 112 by March 2011, the first ever federally mandated reduction requirements. The political pressure Sunflower, Tri-State and their allies have apparently brought to bear upon the KDHE is troubling in its own right.

KDHE Response:

Determination of effects from mercury on livestock and vegetation and mercury modeling are not required as part of the PSD permitting process. See KDHE Response to Comments 175 and 176 regarding the regulation of mercury emissions from coal fired power plants. KDHE operates wet deposition monitoring sites both upwind and downwind from the proposed Holcomb unit. The upwind site is located at Cimarron National Grasslands. The downwind site is at Scott State Lake. The Scott State Lake site is well positioned to evaluate any regional impacts the proposed plant would have on downwind water resources.

The KDHE Bureau of Environmental Field Services monitors and the Bureau of Water regulates stream quality. Their respective websites are:

http://www.kdheks.gov/befs/tech_svcs_section.html

http://www.kdheks.gov/water/index.html

For upcoming regulations that the Holcomb expansion may be subject to, please refer to KDHE Response to Comment 139.

Comment 178:

Due diligence for this permit is not satisfied if, under any regulation, the only question that can be answered about the proposed coal plant's emission profile is the quantity of a highly

toxic substance that is emitted. The current draft permit should be denied, or at the very least further adequate data on (especially mercury) emissions from the proposed plant be determined, modeled for regional impacts, and shared with the Kansas public.

KDHE Response:

Please refer to KDHE Response to Comments D, F, G, 34 and 146.

M. COMMENTS FROM KANSAS INTERFAITH POWER & LIGHT (Comments 179-185)

Comment 179:

One of the most egregious emitters of carbon dioxide into the atmosphere is coal plants, (producing approximately 40 percent of the nation's CO_2 emissions) thus contributing greatly to global climate change.

KDHE Response:

Please refer to KDHE Response to Comments I and 37.

Comment 180:

Coal fired plants can scar peoples lungs, destroy habitats, and pollute local water supplies with their waste. Millions of gallons of waste slurry are produced and dumped by coal plants every year.

KDHE Response:

Please refer to KDHE Response to Comments D, F and G.

No waste slurry will be generated at the facility.

Comment 181:

Coal plants use a significant amount of water to produce electricity. Therefore, we believe that approval of this permit will threaten the water supply (from the Ogallala aquifer) of hundreds of irrigation farmers and businesses in the area. In addition, the proposed plant would be using a Kansas aquifer to produce electricity that that would mostly be used outside of Kansas.

KDHE Response:

Please refer to KDHE Response to Comments C and 31.

Comment 182:

The financial investment needed for this coal plant could delay needed investment in clean and sustainable energy sources that will be so needed in Kansas' future.

KDHE Response:

Please refer to KDHE Response to Comments A and D.

Comment 183:

It is no secret that nations all over the world are implementing carbon emission trading schemes and there is a high probability some form of legislation dealing with carbon emissions will become law in the coming years. Additionally, now that the Environmental Protection Agency has listed carbon dioxide as a pollutant in its recent endangerment finding, it is bound by law to act to protect U.S. citizens.

KDHE Response:

Please refer to KDHE Response to Comments I and 37.

Comment 184:

Changes in federal legislation and/or rules might make this proposed development fiscally impractical at some point in time. Western Kansas is home to thousands of low-income families who would be negatively impacted by electricity rate hikes borne from "unforeseen" regulatory burdens. Coal-fired electricity generating plants may be targeted for regulation in the future and we would like some assurance that these additional burdens will not negatively affect low-income families.

KDHE Response:

Please refer to KDHE Response to Comments D and 139.

Comment 185:

Alternatives to coal-fired power abound. Our state is ranked #2 in wind energy potential, and has proven natural gas reserves. A natural gas fired power plant instead of the Holcomb facility would provide the fraction of power that Kansans need, be more compatible with future wind power generation, emit less air pollutants, use less water and provide dependable power without the risks and uncertainties of coal.

KDHE Response:

Please refer to KDHE Response to Comments A, D, 39 and 103.

N. TECHNICAL COMMENTS FROM INDIVIDUALS

Comment 186:

Tri-State will build just outside of Colorado because of the increasing restrictions in Colorado over coal generation, and because they perceive Kansas as lax in preserving air quality and in controlling air pollution.

While there are many scientific studies on the health and environmental dangers due to coal burning, I would like to draw your attention to a September 2010 report from the Clean Air Task Force, a nonprofit scientific research organization. The report titled "The Toll From Coal: An Updated Assessment of Death and Disease from America's Dirtiest Energy Source", reiterates that "Among all industrial sources of air pollution, none poses greater risks to human health and the environment than coal-fired power plants".

KDHE Response:

Please refer to KDHE Response to Comments D, F and 32.

Comment 187:

Much of the report addresses fine particle pollution (e.g. soot, acid droplets, metals), which is particulate matter smaller than 2.5 microns, or less than one-hundredth the width of a human hair. Being so tiny, this pollution evades the human lung's natural defenses, and is transported to vital organs. With a focus on the nation's roughly 500 coal-fired power plants, the report found that "fine particle pollution from existing coal plants is expected to cause nearly 13,200 premature deaths in 2010. Additional impacts include an estimated 9,700 hospitalizations and more than 20,000 heart attacks per year, asthma attacks, emergency room visits, hospital admissions, and lost workdays. The total monetized value of these adverse health impacts adds up to more than $100 billion per year".

In Figure 2 - "Power Plant Mortality Per 100,000 Adults", a geographic and energy matrix of the United States correlates death rates with proximity to coal burning power plants. States with more coal plants fare the worst, and those with few coal plants fare better. California with very few coal fired plants is estimated to have only 41 coal-related premature deaths in 2010. Whereas, West Virginia, with the highest dependency on coal powered electricity, ranks first in coal mortality risk.

KDHE Response:

Please refer to KDHE Response to Comments F and 39.

Comment 188:

Stack scrubbers merely move the toxins into another venue, distributed among the populace in different media. A major example is the radioactivity of both the coal and the stack emissions, fully within the purview of the Bureau of Air and Radiation's mission.

According to the US Geological Survey, coal contains radioactive elements of uranium (U), thorium (Th), and their numerous decay products, including radium (Ra) and radon (Rn). "Virtually 100 percent of the radon gas present in feed coal is transferred to the gas phase and is lost in stack emissions. In contrast, less volatile elements such as thorium, uranium, and the majority of their decay products are almost entirely retained in the solid combustion wastes. Modern power plants can recover greater than 99.5 percent of the solid combustion wastes, the concentration being approximately 10 times the concentration in the original coal." Fly ash emitted by a power plant carries into the surrounding environment 100 times more radiation than a nuclear power plant producing the same amount of energy.

The primary ways that the general public is exposed to radioactive fly ash is from groundwater seepage from fly ash land disposal (irregular exposure), and from fly ash additive to concrete used in homes and elsewhere (widespread exposure). Also, bottom ash is used widely for snow and ice control - http://www.epa.gov/rpdweb00/tenonn/coalandcoalash.html. Although the radon (Rn) in the coal goes out the coal plant stack as gas, radon gas is subsequently emitted from concrete containing fly ash in concentrations up to 10% of background radon in soil. It would be an exercise in futility to install a radon mitigation system for soil under a house, when the concrete floor and foundation itself is emitting radon.

KDHE Response:

Please refer to KDHE Response to Comments F, G, and L.

Comment 189:

Another avenue by which coal burning power plants disperse their toxins is at the mine face. Notwithstanding the multiple dangers to coal miners of radon gas poisoning, roof collapse, gas and dust explosions, and pneumoconiosis (black lung disease), the toxic dangers to the general public from coal dust is effectively transferred to coal mining country. As a result of public health and clean air regulations, coal is scrubbed at the mine with chemicals to remove impurities before shipment to coal fired power plants, and the nearby sludge ponds all contain a witches' brew of potent substances. The health and environmental danger became evidently clear on 23 December 2008 in Martin County, Kentucky, when a dam belonging to industry heavyweight Massey Energy failed, causing a toxic spill 30 times larger than the Exxon Valdez disaster.

KDHE Response:

The PSD permit process does not address coal mine activities.

Comment 190:

The site-specific impacts in Finney County are a small part of the picture. The downstream multi-state impacts of the toxic plume due to mercury and other elements, and the distant dangers to coal miners and coal mining communities are all a direct result of the coal fired

generating plant appetites for the coal. The most widely dispersed health and environmental danger is the CO2 emissions contributing to global climate disruption.

With so many better options for Kansas to supply our electric needs and create better economic opportunities, I would ask the Bureau of Air and Radiation to provide proof that Tri-State Generation & Transmission and Sunflower Electric Power Corporation have adequately addressed the full range of health and environmental dangers emanating from their proposed 895MW coal plant, in keeping with stringent criteria of evaluation.

KDHE Response:

The permit applicant has addressed all health and environmental impacts in accordance with the PSD permitting requirements. Please refer to KDHE Response to Comments D, E,F, G, I, and 39.

Comment 191:

How does Sunflower's application address the adverse synergistic combination of naturally high particulate matter and its proposed plant's un-natural emission of more particulate matter plus a large amount of NO_X?

KDHE Response:

Sunflower's Application addresses potential particulate matter (PM) and NO_x emissions from Holcomb 2 in accordance with all legal requirements.

EPA establishes health-based national ambient air quality standards (NAAQS) for the criteria pollutants, including PM, and NO_2, and determines whether air quality in a given area satisfies the NAAQS. Sunflower conducted air quality modeling in accordance with the applicable air quality permitting rules to evaluate the potential impact of the Holcomb 2 sources on the PM and NO_2 NAAQS. The modeling results demonstrate that potential emissions of PM and NO_2 will not cause or contribute significantly to any exceedance of the $PM_{2.5}$ or the NO_2 NAAQS, taking into consideration current background levels representative of the area required to be evaluated.

Comment 192:

Does Sunflower conclusively demonstrate that its design is truly the best available technology for reducing NO_X emissions?

KDHE Response:

Yes, Sunflower has demonstrated that its design is the best available control technology for potential NO_x emissions in accordance with the procedures required for conducting a BACT

analysis. Sunflower was required to conduct a top-down BACT analysis for KDHE's review according to EPA's process.[49] *There are five key steps in this process:*

- *Step 1 – Identify all potential available control technologies.*
- *Step 2 – Eliminate technically infeasible options.*
- *Step 3 – Rank remaining control technologies by control effectiveness.*
- *Step 4 – Evaluate most effective controls and document results.*
- *Step 5 – Select BACT.*

Sunflower's BACT analysis was based on demonstrated technology, available and applicable to the proposed project. Sunflower's evaluation of potential NO_x control technologies is set forth in Appendix E of its Application, as updated. The NO_x control technologies that were eliminated by Sunflower include technologies that lack commercial experience and technologies which have lower NO_x reduction capabilities than the NO_x control technologies selected for H2. A combination of low NO_x burners-overfired air-selective catalytic reduction was selected as BACT for NO_x. The NO_x emissions limit in the permit was based on established control rates achieved with demonstrated technology in similar applications. Sunflower's Application also addresses potential NO_x emissions from other Holcomb 2 sources in accordance with all legal requirements.

Comment 193:

Does Sunflower's proposed design adequately deal with SO_2?

KDHE Response:

Yes, Sunflower's proposed design adequately addresses potential SO_2 emissions from H2 and other Holcomb 2 sources in accordance with all legal requirements.
Sunflower conducted a BACT analysis to select the SO_2 emissions control technology for H2. Sunflower's evaluation of potential SO_2 control technologies is set forth in Appendix E of its Application, as updated. A number of the technology options that were initially considered for H2 were eliminated by Sunflower due to lower SO_2 reduction capabilities than the dry flue gas desulfurization (FGD)) SO_2 control technology selected.

Sunflower also conducted a BACT emissions limitations analysis for the H2 steam generator and other Holcomb 2 sources of SO_2 emissions as described at Part 4.0, Section 4.2, of the Application, as updated. The BACT emissions limitations and the SO_2 emissions control technology to be employed the are consistent with permits recently issued by other regulatory agencies that have similar obligations under the Clean Air Act (CAA).

The updated Application also reduced the proposed H2 tier-I emission limitation to 0.06 lb/MMBtu, the same as for the Wet FGD-equipped Iatan 2. The H2 tier-2 limit of 0.085 lb/MMBtu is retained in the event that the operator or owner determines that a higher-sulfur coal is to be used for reasons that could include improvements in the reduction of mercury

[49] Table B-1. – Key Steps in the "Top-Down" BACT Process, p. B.6, *New Source Review Workshop Manual*, Draft October 1990.

emissions. Both of these limitations are consistent with reductions in SO_2 of about 94%, consistent with those for Iatan 2 and other recently permitted facilities and therefore represent the proper application of BACT principles.

Comment 194:

Is it appropriate to accept Sunflower's proposal to use less than best available technology for SO_2?

KDHE Response:

Please refer to KDHE Response to Comment 193.

Comment 195:

Does Sunflower's application adequately consider the Indigo MAPSystem™ alternative for SO_2, mercury, NO_X, and particulate matter removal?

KDHE Response:

Yes, the Sunflower application considered this and other alternative control systems for SO_2, mercury, NO_x, and particulate matter removal.

The Indigo MAPSystem is identified as a technology suited for application on smaller capacity coal fired boilers. This technology has undergone pilot scale trials and continues to progress through development phases. The suite of emission control technologies selected by Sunflower for controlling SO_X, , and $PM_{10}/PM_{2.5}$ at H2 have been shown by Sunflower to be BACT for each of these pollutants. Mercury control at H2 will incorporate activated carbon injection or sorbent injection to meet the permit emissions limitations for that pollutant.

The application of MAPSystem technology is primarily intended for retrofit applications on smaller units and would be installed upstream of existing ESPs. The technology performance levels referenced by the commenter are from pilot-scale tests, which do not ensure that comparable emission reductions will be achieved at commercial scale.
A feature of the MAPSystem is the Indigo Agglomerator, which is reported to enhance chemical reactions and remove fine PM (generally referred to as $PM_{2.5}$). The use of the Indigo Agglomerator was initially considered by Sunflower as a potential $PM_{10}/PM_{2.5}$ control option. As described in Appendix E of the updated Application, this technology option was eliminated from further consideration, as it has been applied only upstream of ESPs and has not been demonstrated to be effective in combination with fabric filters. Since H2 is proposed to be constructed with a fabric filter, which has very high collection efficiencies for fine PM, an Indigo Agglomerator would serve no purpose for H2.

Comment 196

Does Sunflower's application adequately consider these alternative strategies: sodium bi-carbonate injection to achieve SO_2, HCl, HF, and fly ash reductions, the

DynaWave™/Membrane WESP (wet electrostatic precipitator) system to achieve SO_2, SO_3, Hg^{+2} reductions, and the switched-mode-power-supply (SMPS) precipitator for fine particulate removal ($PM_{2.5}$).

KDHE Response:

The Sunflower application adequately considered these and other alternative control systems for SO_2, SO_3, HCl, HF, mercury, and particulate matter removal.

The commenter discusses the collateral benefits that may one day be achieved by the three alternative systems identified in this comment. Sunflower has relied upon the proven collateral benefits in achieving SO_2, SO_3, mercury, H_2SO_4, PM_{10}, $PM_{2.5}$, and HAPs emission reductions with Dry FGD/PAC injection/fabric filter systems. (Although a Wet FGD was considered in the SO_2 BACT analysis, it was determined not to be BACT for H_2SO_2 emissions.)

Dry sorbent injection processes are being considered as retrofit options for removing SO_2, HCl, HF, and H_2SO_4. These dry sorbent injection options are not as effective in removing acid gases as the Dry FGD/fabric filter system that will be used for H2 and therefore do not represent BACT for SO_2 and H_2SO_4.

The technical paper concerning the DynaWave/Membrane WESP technology referenced by the commenter describes the combination of two technologies: the DynaWave Reverse Jet Scrubber and Membrane Wet ESPs. While the paper discusses typical inlet conditions and SO_2, SO_3, and PM removal efficiencies that can be achieved by the combined systems, the paper does not present any information concerning the effectiveness of actual combined installations of these two technologies. The primary function of a downstream Wet ESP is reduction of H_2SO_4 and PM. Sunflower considered the use of Wet ESP as part of its H_2SO_4 and $PM_{2.5}$ BACT analyses and determined in each case that a Wet ESP is not BACT.[50]

At pilot-scale testing, the membrane Wet ESP also has indicated reductions of oxidized mercury (Hg+2). The mercury control technology selected for H2 is capable of higher mercury removal than the co-benefits observed in the pilot-scale testing of the membrane Wet ESP that was presented in the technical paper identified by the commenter.[51]

The application of Switch Mode Power Supplies (SMPS) for powering ESPs is one of a number of options for attempting to improve ESP collection efficiency. There is some evidence that SMPS provides improved collection for some ESP applications compared to ESPs powered by conventional transformer-rectifier (TR) sets. However, almost all new PC-fired power plants include a fabric filter for PM, based on that technology's superior PM collection efficiency over all particulate sizes, including $PM_{2.5}$. In this case, fabric filter technology was determined to be BACT for H2 PM_{10}/$PM_{2.5}$ emissions, as it represents the best technology for controlling such emissions.

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[50] See Sections 6.1.4.1 and 9.1.1.1.3 of Part __ of the Application, as updated..

[51] This is in part because almost all of the mercury present is in the elemental, rather than the oxidized, form.

Sunflower's analysis considered the collateral benefits that arise from the primary emissions control technologies for H2, including which benefits that have been proven or measured on H1. The combined effectiveness that accrues from the deployment of the Dry FGD/PAC injection/fabric filter suite of control technologies is superior to any other commercially available technology. The technologies identified by the commenter do not constitute BACT for H2 for any pollutant and are not otherwise required for H2 on either legal or factual grounds.

Comment 197:

Hitachi has developed techniques for implementing oxy-fuel combustion technology on existing power plants, and one of the papers says, "Only minimal modifications to the boiler house equipments and limited alterations to the air quality control system will be needed." This technology substantially reduces NO_x as well as CO_2. Has oxy-fuel combustion technology been properly considered in best available alternatives to the proposed design of the Holcomb Expansion Project?

KDHE Response:

Oxy-fuel combustion systems are being developed as a possible alternative for carbon dioxide (CO_2) capture and storage (CCS) for coal-fired power plants for both retrofit applications and for new unit or re-powering applications. However, oxy-fuel combustion technology is not a proven technology, especially on large steam generators, with only a few pilot plants worldwide. The comment that only minimal modifications will be needed to boiler house equipment and air quality control system is unproven. Therefore, to the extent that this technology has the potential to reduce NO_x emissions, it is not BACT for H2.

Under current law, there is no requirement of CO_2 capture at H2. The DOE National Energy Technology Laboratory (NETL) estimates that construction of a new oxy-fuel power plant would increase the cost of electricity by about 65 percent and reduce the net plant efficiency by approximately 25 percent, as compared to a new air-oxidized PC-fired power plant without CO_2 capture.

The implication that Sunflower must evaluate oxy-fuel in the design of the Expansion Project is not well-founded. Such an evaluation is not a requirement of the PSD permitting process. For these reasons, construction of an oxy-fuel combustion system facility would fundamentally re-define the source that is the subject of Sunflower's Application. There is no lawful basis for such a redefinition to be imposed on the Expansion Project.

COMMENT 198:

Does Sunflower's application adequately consider instrumentation that measures particulate matter by scattered light?

KDHE Response:

The statutory and regulatory provisions that address the monitoring of potential PM emissions from Holcomb 2 do not require the use of scattered light technology instrumentation. Sunflower Holcomb 2 is subject to opacity limits in accordance with federal regulation (40 C.F.R. Part 60, Subpart Da, NSPS for Electric Utility Steam Generating Units) and with state regulation (K.A.R. 28-19-650).

As specified in the Sunflower Holcomb 2 permit, the requirement to continuously monitor the opacity of visible emissions from Holcomb 2 does not apply because a continuous monitoring system for PM is to be installed, calibrated, maintained, and operated to demonstrate compliance with filterable PM emission limitations established in the permit. The exemption from opacity monitoring requirements is allowable at 40 C.F.R. 60.42Da(b) and 60.48Da(p) and qualifies as "other applicable air quality regulations" in K.A.R. 28-19-650(a).

A continuous PM monitor (PM CEMS) is required by the permit (see Monitoring Requirements #1). This requirement is included as a replacement for the opacity monitor that was originally proposed in 2006, and is now allowed under EPA NSPS for PM to be installed in lieu of an opacity monitor.

Comment 199:

How does Sunflower's application adequately account for and deal with the addition of arsenic to the biosphere by gaseous discharge and solid waste?

KDHE Response:

The Sunflower Holcomb 2 air permit requires testing for trace metals, including arsenic, at the stack in accordance with EPA-approved methods and with the provisions in the permit. EPA has announced intentions to propose a new utility MACT in near future that would address emissions of hazardous air pollutants (HAPs) from coal fired boilers. Sunflower will be required to comply with any final MACT rule by making the necessary physical or operational changes to the unit.

Fly ash and bottom ash from coal-fired power plants are classified as non-hazardous industrial solid wastes. Industrial solid waste management is outside the scope of this air permit. Standards for industrial landfills that receive fly ash and bottom ash are contained in Kansas administrative regulations in Chapter 28, Article 29 authorized by Kansas statutes in Chapter 65 Article 34. Requirements for landfill liners and cover are addressed in the industrial landfill permitting process. KDHE's Bureau of Waste Management administers the industrial solid waste program with which Sunflower's industrial solid waste management plan will need to comply.

Comment 200:

How is Sunflower proposing to prevent long-term hazardous-material volatilization (of semi-volatile compounds) and seepage into groundwater after rainfall?

KDHE Response:

Fly ash and bottom ash from coal-fired power plants are classified as non-hazardous industrial solid wastes. Standards for industrial landfills that receive fly ash and bottom ash are contained in Kansas administrative regulations in Chapter 28, Article 29, authorized by Kansas statutes in Chapter 65 Article 34. Requirements for landfill liners and cover are addressed in the industrial landfill permitting process. KDHE's Bureau of Waste Management administers the industrial solid waste program with which Sunflower's industrial solid waste management plan will need to comply.

Comment 201:

Does the Holcomb Expansion Project proposal adequately consider effluent mineralization as an alternative way to remove pollutants from flue gases which convert potentially harmful substances to relatively passive forms?

KDHE Response:

The commenter references conference papers from Air Quality VII, October 2009, that describe effluent (flue gas) mineralization in the context of carbon management, namely CO2 capture and sequestration. Sunflower Holcomb 2 is subject to PSD review, including BACT, for NO_x, SO2, CO, PM/PM10, Sulfuric Acid Mist, and VOC due to a net significant increase in emissions for each of these regulated pollutants. Sunflower was required to prepare a BACT analysis for KDHE's review according to EPA's top-down BACT analysis process. [52] *Section 4.1.2.1 of Part 4.0 of the updated Application describes the environmental advantages and disadvantages of Wet FGD and Dry FGD systems as part of Sunflower's SO_2 BACT analysis. The potential for limestone forced oxidation (LSFO) Wet FGD systems to produce synthetic gypsum*[53] *is addressed in this review. A serious unresolved issue with such systems is their potential to limit the beneficial use of the FGD wastes.*

One paper referenced in the comment (<u>Mineralization of Carbon Dioxide (CO_2) from Coal Combustion Flue Gas</u>, by Weber, Reddy, and Fahlsing) provides a review of laboratory-scale tests, which examine the capture and mineralization of flue gas CO_2 by fly ash. Direct mineralization of CO_2 may at some point in the future become a method of sequestering captured CO_2, as other researchers are studying that possibility; but these concepts are at the early stages of development. CO_2 emissions limits and controls are not included in the Sunflower Holcomb 2 permit and are not required by current federal or state regulations in effect.

[52] Table B-1. – Key Steps in the "Top-Down" BACT Process, p. B.6, *New Source Review Workshop Manual,* Draft October 1990.
[53] Gypsum is a naturally occurring mineral.

Comment 202:

Why does Sunflower's "Control Technology Analysis" not mention 2004 mercury test program and the success achieved during that test? And why does Sunflower not propose to include a substantial improvement that has been successfully demonstrated at its own facility?

KDHE Response:

Mercury emissions limits are set in the NSPS for Electric Utility Steam Generating Units at 40 C.F.R. Part 60 Subpart Da (60.45Da). The NSPS mercury emissions limit for Sunflower is 0.097 lb/GWh. Emission of mercury is limited by state-only conditions in the permit, and Sunflower has agreed to a limit of 0.020 lb/GWh. This limit is well below the NSPS emissions limitation.

Mercury is not a pollutant regulated under New Source Review, and Sunflower is not required to include mercury controls in its control technology analysis for the permit application nor is Sunflower required to include discussion of any mercury emissions control experiments. EPA has announced intentions to propose a new utility MACT in near future that would address emissions of hazardous air pollutants (HAPs) from coal fired boilers. Sunflower will be required to comply with any final MACT rule by making the necessary physical or operational changes to the unit.

The test program referenced by the commenter was reported to KDHE, and is referenced in the 2006 permit application, and in the updated Application at Appendix L. Specifically, Sunflower found the injection of brominated powdered activated carbon (PAC), the addition of a bromine solution to the coal, and the blending of a Western Colorado bituminous coal with PRB coal enhanced capture of mercury from the stack gas effluent. These practices are not precluded by the permit from being utilized at Holcomb 2. Sunflower will install PAC or sorbent injection equipment for the Holcomb 2 steam generator so that it can be used as necessary to achieve the emission limitation established.

Comment 203:

Why does Sunflower not propose to use best available technology that has been proven to work for them? How well does Sunflower's proposed treatment of mercury from PRB coal succeed in capturing mercury and in keeping it from re-entering the biosphere later? And why does Sunflower not propose to include a substantial improvement that has been successfully demonstrated at its own facility?

KDHE Response:

Mercury emissions limits are set in the NSPS for Electric Utility Steam Generating Units at 40 C.F.R. Part 60 Subpart Da (60.45Da). The NSPS mercury emissions limit for Sunflower is 0.097 lb/GWh. Emission of mercury is limited by state-only conditions in the permit, and

Sunflower has agreed to a limit of 0.020 lb/GWh. This limit is well below the NSPS emissions limitation.

The statutory and regulatory provisions that address potential mercury emissions from H2 do not require either the use of BACT or MACT emissions control technology or the inclusion of a BACT-based or MACT-based emissions limitation in the permit. However, Sunflower's Application addresses all statutory and regulatory issues applicable to potential mercury emissions from H2; and the permit provisions relating to potential mercury emissions from H2 satisfy all applicable statutory and regulatory requirements.

EPA has announced intentions to propose a new utility MACT in near future that would address emissions of hazardous air pollutants (HAPs) from coal fired boilers. Sunflower will be required to comply with any final MACT rule by making the necessary physical or operational changes to the unit.

The commenter quotes sorbent material utilization savings from a conference paper on the Luehr Filter with Reaction Chamber / Recycle Process and asks why Sunflower has not considered using a technology that has been proven to work for them. Sunflower has not used the referenced process nor are they required to consider it in the permit application. KDHE's air permit for the Sunflower Holcomb 2 plant establishes air emissions limitations for regulated pollutants, it does not establish standards for material utilization. Sunflower will install powdered activated carbon or sorbent injection equipment for the Holcomb 2 steam generator.

Sunflower is not precluded by the permit from using any mercury control system available to achieve the mercury emissions limitations in the permit. The test referenced in the comment was for a period slightly less than 30 days; and the other methods demonstrated might prove to be just as effective. Accordingly, the technology (other than some type of injected sorbent) ultimately to be used has not been determined.

Comment 204:

Does Sunflower's application adequately describe the extent to which Sunflower might later decide to recycle waste material and the potential dangers associated with such a practice? And if mercury encapsulated in wall-board leaks out to that extent, how easy might it be for the un-encapsulated mercury in Sunflower's waste dump to escape?

KDHE Response:

The statutory and regulatory provisions that establish the air quality issues that must be addressed by Sunflower's Application do not require consideration of the issues posed by this comment. See KDHE Response to Comments 199, 200 and 203. The reuse of coal combustion products (CCP) in commerce is encouraged by the statutes and regulations applicable to these materials. The decision on whether and how coal combustion products are reused in commerce is specific to each plant, the control equipment at the plant, and the markets available to the plant.

Fly ash and bottom ash from coal-fired power plants are classified as non-hazardous industrial solid wastes. Industrial solid waste management is not included in the air permit. Standards for industrial landfills that receive fly ash and bottom ash are contained in Kansas administrative regulations in Chapter 28, Article 29 authorized by Kansas statutes in Chapter 65 Article 34. Requirements for landfill liners and cover are addressed in the industrial landfill permitting process. KDHE's Bureau of Waste Management administers the industrial solid waste program with which Sunflower's industrial solid waste management plan will need to comply.

COMMENT 205:

How does Sunflower deal with the air-entrainment dilemma?

KDHE Response:

The "dilemma" asserted in this comment relates to the conflict between removing mercury from plant effluent and degrading the quality of potential byproducts from the air pollution control equipment. This dilemma is beyond the scope of the air quality permit. The air permit does not establish standards for byproduct quality. The reuse of coal combustion products (CCP) in commerce is encouraged by the statutes and regulations applicable to these materials. The decision on whether and how coal combustion products are reused in commerce is specific to each plant, the control equipment at the plant, and the markets available to the plant.

Comment 206:

These include in-situ methods like X-ray absorption spectroscopy. How do Sunflower's proposed mercury monitoring methods compare with in-situ methods like X-ray absorption spectroscopy?

KDHE Response:

KDHE's air permit for Sunflower Holcomb 2 requires installation and operation of a continuous monitoring system for mercury, either a CEMs or a sorbent trap, to demonstrate compliance with the emissions limitations set in the permit. This requirement complies with the federal regulations for emissions monitoring at 40 C.F.R. 60.49Da. The leading CEMS-type mercury monitors are based on atomic fluorescence. All mercury CEMS must comply with EPA Performance Specification 12A, which was promulgated as part of the Portland Cement MACT [75 Fed. Reg. 54,970 (September 9, 2010)].
The other approved method of continuous mercury measurement is by means of the Sorbent Trap Monitoring System (STMS). This procedure is defined in EPA Performance Specification 12B. The STMS continuously draws a sample of flue gas through a packed sorbent column (e.g., activated carbon) and then analyzes the sorbent sample after the sampling cycle is complete.

Comment 207:

One paper explains how adverse mercury effects are naturally offset by dietary selenium, indicating that the health impact of mercury is location dependent. Another paper explains the procedures used to certify the elemental and oxidized mercury generators. Does Sunflower's application adequately relate the health hazards of mercury to local conditions?

KDHE Response:

Existing regulations regarding mercury are not site specific based upon the levels of dietary selenium that a person would receive. The statutory and regulatory provisions that establish the air quality issues that must be addressed by Sunflower's Application, do not require consideration of this issue. Sunflower's Application addresses potential mercury emissions from H2 in accordance with all current legal requirements. Mercury emissions limits are set in the NSPS for Electric Utility Steam Generating Units at 40 C.F.R. Part 60 Subpart Da (60.45Da). The NSPS mercury emissions limit for Sunflower is 0.097 lb/GWh. Emission of mercury is limited by state-only conditions in the permit, and Sunflower has agreed to a limit of 0.020 lb/GWh. This limit is well below the NSPS emissions limitation.
Sunflower will install powdered activated carbon or sorbent injection equipment for the Holcomb 2 steam generator. EPA has announced the proposal of a new utility MACT in the near future, which will likely include regulation of mercury. Sunflower will be required to comply with the limits contained in a final rule through physical or operational changes. MACT standards are national standards and do not vary by location, but rather are based on demonstrated achievable control technologies for hazardous air pollutants.

Comment 208:

Has Sunflower adequately considered carbon recycling?

KDHE Response:

The statutory and regulatory provisions that establish the air quality issues that must be addressed by Sunflower's Application do not require consideration of the issue posed by this comment. There is no current requirement that Sunflower consider "carbon" or CO_2 recycling in connection with the Expansion Project.

Comment 209:

Has Sunflower adequately considered carbon capture and sequestration alternatives?

KDHE Response:

The statutory and regulatory provisions that establish the air quality issues that must be addressed by Sunflower's Application do not require consideration of carbon capture and sequestration as addressed in this comment. CO2 emissions limits and controls are not included in the Sunflower Holcomb 2 permit and are not required by current federal or state regulations in effect.

Comment 210:

Has the Holcomb Expansion Project been evaluated for its ability to incorporate CO_2 removal as in the IGCC Tenaska project?

KDHE Response:

The statutory and regulatory provisions that establish the air quality issues that must be addressed by Sunflower's Application do not require consideration of carbon capture and sequestration as addressed in this comment. CO2 emissions limits and controls are not included in the Sunflower Holcomb 2 permit and are not required by current federal or state regulations in effect.

Comment 211:

Has Sunflower adequately justified use of water-cooled condensing as opposed to the air-cooled condensing the Tenaska plant will employ?

KDHE Response:

The use of air-cooled condensing (ACC) of steam is a much less efficient design than that proposed for the H2 unit. Use of ACC at Holcomb 2 would result in an increase in regulated air pollutant emissions per unit of electricity produced compared to the use of a mechanical draft cooling tower that will be used for Holcomb 2.

The water rights for the facility have been acquired, and the use of the water for industrial purposes is provided in the regulations relating to water rights as determined by the Kansas Division of Water Resources of the Department of Agriculture. Issues relating to water rights and water use fall within the purview of that Department and are not germane to this proceeding. In response to public inquiries, DWR developed a fact sheet in September 2010 that provides information about water rights for the proposed Sunflower Holcomb 2 facility. The fact sheet explains how water rights could be acquired and converted to supply water to the power plant. DWR points out that the Kansas Water Appropriation Act restricts developing new water rights in that area, and restricts changes from one use to another, so that any new use cannot increase the amount of water consumed from the Ogallala aquifer.

Comment 212:

What measurements, studies, and reports have been completed or reviewed that assess the effects on human health caused by the inhalation, ingestion and/or exposure to each of the known pollutants that will be emitted by the proposed facility? Please provide a bibliography of those measurements, studies, and reports along with your conclusions about the effect each pollutant will have on the health of Kansans.

KDHE Response:

KDHE does not perform the types of basic research on human health effects associated with exposure to the criteria pollutants emitted by the proposed Sunflower facility. The National Ambient Air Quality Standards (NAAQS) are established by EPA based on research conducted by independent researchers as well as contract research performed by EPA. This work is reviewed by the EPA Clean Air Science Advisory Committee and a recommendation is made to the EPA Administrator on revisions to the NAAQS. These revisions are performed every five years pursuant to the Clean Air Act requirements. General information on the health effects associated with the criteria pollutants can be found at http://www.epa.gov/air/urbanair/ . More specific information on the research associated with the NAAQS can be found at links to the specific pollutants from the web site. KDHE evaluates a proposed source of air pollution regarding whether it will contribute to a violation of the NAAQS. This was completed as part of the permit process. The conclusion was that the proposed source would not contribute to a violation of the NAAQS and thus would be protective of human health.

Comment 213:

If not covered in your response to the question above, please provide your assessment of what will be the effect on the health of Kansans from the inhalation, ingestion and/or exposure to fine particulate matter (sometimes referred to as PM2.5) from coal combustion emissions from the proposed facility.

KDHE Response:

Please refer to KDHE Response to Comment 212.

Comment 214:

If the amount of emitted pollutants will be at or below current statutory levels, is it assumed that there is no harm to human health? What does KDHE consider an acceptable level of harm?

KDHE Response:

KDHE does not establish thresholds for acceptable levels of harm. Rather, KDHE implements federal National Ambient Air Quality Standards (NAAQS) promulgated by EPA. KDHE adopts the federal NAAQS by reference. These standards are based on health studies conducted by public and private sector scientists that are reviewed by EPA's Clean Air Science Advisory Committee (CASAC). CASAC then makes a recommendation to the EPA Administrator. EPA then sets standards that KDHE uses to evaluate proposed sources of air pollution. The question of what is an acceptable level of harm is not addressed by KDHE but rather by EPA in the process of establishing the NAAQS. Information on that process and links to health effects information for the different pollutants can be found at http://www.epa.gov/air/urbanair/ .

Comment 215:

What measurements, studies, and reports have been completed or reviewed that assess the effects of air pollutants from the proposed facility on surface water and soil quality? Please provide a bibliography of those measurements, studies, and reports along with your conclusions about the effect each pollutant will have on surface water and soil quality.

KDHE Response:

The PSD permitting regulations at 40 CFR 52.21(o) require the owner or operator of any proposed new major source to provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of construction of the new source. The regulations do not require studies of these impacts to be conducted as would occur for a project that triggered an environmental assessment under the federal National Environmental Policy Act.

The soils impact analysis conducted by Sunflower is contained in Part 7.0, Section 1.6 of the permit application. The modeled NO_x, CO and SO_2 emissions from the proposed unit are well below the reference levels cited in the analysis for negative impacts on the soils and the types of native vegetation that occur in the vicinity of the proposed unit. References are contained in the permit application. KDHE concurs that there will be little or no impact on the soils in the vicinity of the plant as a result of the construction of the proposed unit.

The primary impacts of coal fired power plants on surface waters occur through acidification of lakes as a result of deposition of acids formed from acid gas emissions, and the deposition of mercury. The federal Acid Rain Program contained in Title IV of the Clean Air Act is the regulatory tool to address acid deposition from coal fired power plants. The proposed Unit 2 at Sunflower will be subject to the federal Acid Deposition Control provisions of the Clean Air Act.

Please refer to KDHE Response to Comments G, and 203 for information on the regulation of mercury emissions from coal fired power plants.

Comment 216:

Please review the US Supreme Court Ruling of Massachusetts v. EPA (412/07). In October, 2007, you denied a permit submitted by Sunflower Electric for a similar facility. You denied the permit in part on the grounds that carbon dioxide (CO2) is a pollutant that is emitted in very large quantities when coal is burned for electricity generation. You reasoned, "I believe it would be irresponsible to ignore emerging information about the contribution of carbon dioxide and other greenhouse gases to climate change and the potential harm to our environment and health if we do nothing." Please explain why you would or would not today deny an air permit for the proposed Sunflower facility for the same reasons.

KDHE Response:

Please refer KDHE Response to Comments I and 37.

Comment 217:

Public hearing participants, politicians, and media reports have put much attention on the economic benefits and jobs that would be created by the construction of the proposed facility. If you feel compelled to respond to the economic side of this issue, I would ask that you carefully analyze the full lifecycle costs/benefits of putting online for the next two generations a coal burning facility like the one proposed in the Sunflower permit (e.g., pollution from extracting and transporting coal, rising costs as fuel resources are depleted, impacts on health care costs, environmental degradation, etc.). Include in your study a comparative analysis of the lifecycle costs/benefits of other current and emerging renewable electricity generation technologies, including demand reduction through energy efficiency and conservation.

In conclusion, I respectfully request that you deny issuance of this air permit to Sunflower Electric. Our children and grandchildren will face many challenges. One they should not have to face is living with the damage that will be done to their health and their environment by adding the pollution of one more coal burning power plant.

KDHE Response:

Please refer KDHE Responses to Comments A, D, E, F, and 39.

Comment 218:

Greenhouse gases are a harmful pollution problem for coal-fired power plants. But these emissions are not the only threat to human health caused by burning coal as a boiler fuel. The emissions such as mercury, sulfur dioxide, particulate, etc. each have their own health effects even though such are regulated. However, even in regulated amounts the pollutants still have the potential for harmful health effects. Additionally, over time emission standards for various criteria pollutants have been altered to reduce emissions because of recognized adverse health effects. Please recall the reasons that motivated your decision in 2007 to reject Sunflower's application. These reasons have become more compelling since 2007, and justify another denial of Sunflower's application.

KDHE Response:

Please refer KDHE Responses to Comments F, G, H and I.

Comment 219:

Nowhere in the impact reports is there any mention of the expected water consumption by the proposed project. This needs to be stated, and there needs to be a statement of the source of water for the project. It is my understanding that this project will draw water from local ground water sources. In this context:

a. What is the source of the water?

b. How much water will be withdrawn?
c. How do the project's water rights fit in with water rights of other users?

This is an important point, because as water sources become scarcer, and the aquifer is drawn down, who will have priority water rights? The power plant will draw down water in the aquifer, and this will impact water access for all Kansas citizens that rely on this water for farming and other economic activity. Will the power plant water rights supersede the rights of private citizens? If there is to be a water shortage and others have prior rights to the aquifer water how will the plant deal with this, will it shut down or reduce its power output? A reflection of the critical nature of this issue is reflected by the State of Kansas vs the State of Colorado over water rights in the Arkansas River and continues to be an ongoing issue as illustrated. It is well known that the Ogallala aquifer is being drawn down at a rapid rate and in the next century this will lead to water conflicts and decisions will have to be made about which economic activities have precedence in the region – or which water rights have precedence. Either way this project will have a major impact on those decisions and activities.

KDHE Response:

Please refer KDHE Response to Comment C.

Comment 220:

When considering the questions under 219, there needs to be consideration of future economic and environmental change that might occur. That means that the following types of questions should be addressed:

a. How will the withdrawal by the plant affect water resources downstream in the aquifer.
b. How will aquifer impacts affect present and future ability of individual citizens to continue their economic activities (irrigation agriculture primarily).
c. How will water withdrawal, use and treatment affect the riparian and other ecosystems in the region?

KDHE Response:

Please Refer to KDHE Responses to Comments C and E.

Comment 221:

How will other environmental and economic changes impact the security of the water supply (aquifer) to the plant and other competing economic activities? This includes legal issues, issues related to aquifer recharge, regional land use/land cover change, ecological impacts and climate change.

KDHE Response:

Please refer KDHE Responses to Public Comments C, E and I.

Comment 222:

There is a need within the proposal to provide more sophisticated future scenarios under which this power plant will be operating over its 50-100 year lifespan. There is an extensive literature on this topic. Within this literature (see a sample of citations below) there is ample evidence that this region can expect significant changes in its climate and access to water resources. The report should consider several aspects of plant-climate interactions, including:

a. This plant will contribute to the problem of climate change. In effect this plant alone will be the difference between putting Kansas on a path of the IPCC defined Special Report on Emissions Scenarios (SRES) as opposed to putting Kansas in the **A2 scenario** into the future. This change has significant impacts on future climate projections and hence the other environmental impacts associated with this plant. Although CO2 emissions are not to be considered as part of the "environmental impacts" of this plant, the fact the plant will be built means we should change the scenarios under which we evaluate the plants environmental impacts in the future. None of these scenarios are considered in any way in the proposal, nor does it consider possible impacts of climate change on the operation of the plant, including changes to water supply to the plant and the rest of the community.

b. There have been a number of studies that evaluate the impacts of climate on this region of the US and the State (e.g. Feddema et al 2008, the US Climate Impact assessment, the IPCC climate report (2007)All creditable science suggests that continued accumulation of greenhouse gasses will change the climate of the region. However, many impact studies (e.g. the Feddema et al study on Kansas) assume the A1B scenario as a starting point; an assumption that might be attainable for Kansas without this plant. Under these conditions we can expect water deficit conditions in this region to increase from 4-8 inches between 2050 and 2100. There is no doubt this will have a significant impact on agriculture, and put significant stress on the region's water resources and more specifically the Ogallala aquifer. However, with the addition of the power plant to the Kansas emissions profile, we are clearly on an IPCC A2 (or higher) scenario as a state, which would change these projections to 6-11 inches of water deficit over the same time period for the region. In addition, current studies clearly indicate that on a global scale present changes in greenhouse gas emissions are higher than any of the IPCC SRES scenarios and show that on a global scale we are on a path of climate change that would arrive at impacts exceeding the conditions suggested in any of the present studies on future climate impacts on Kansas. None of these issues are covered in the report, nor is there any discussion how this power plant will interact with the local community and environment within the context of these projected changes, which have a better than even chance of becoming reality. In the alternative, should accounting for the specific climate change impacts prove beyond the scope of KDHE of Sunflower's capacity, then KDHE should instead require a BACT analysis for the plant. The EPA has already issued an endangerment finding regarding the health and environmental impacts of greenhouse gases, and KDHE must incorporate this significant regulatory step into its analysis.

KDHE Response:

Please refer KDHE Responses to Comment I, 37, and 39.

A BACT analysis has been performed for this project as outlined in Section III.B of this document.

Comment 223:

An analysis is needed of the potential economic impact of this plant on the state's economy should a carbon tax, carbon cap and trade, or other carbon regulation become a reality in the US. Given that this one plant can change the projected scenario under which the state of Kansas might be viewed in a federal or even global analysis of carbon emissions, there might be significant repercussions on the cost reducing future emissions. Given that much of the electricity produced by the plant is for export, there is the problem that any potential costs under such regulatory environments will be borne by citizens and businesses from the state of Kansas, as opposed to the users of the electricity. There is no discussion of how future business scenarios will be dealt with from an economic perspective, nor who will be responsible for the burden of carbon related expenses due to these emissions. This is particularly important since CO2 is already considered a criteria pollutant by the U.S. Supreme Court, and this is likely to have significant economic impacts should the plant or State not comply with regulatory activities to be implemented as soon as January 2011.

It ignores many potential impacts of this plant on the people of Kansas and the Kansas environment. The level of analysis performed makes it very difficult for a neutral party to obtain an unbiased and realistic cost benefit analysis of the project. By ignoring the future the impacts of this plant on water resources; its interaction with future climate and future economic development scenarios for the region; and its interaction with potential future carbon regulatory environments, the true costs of the proposal are not well documented. Each of these costs could easily be deferred to the State or individual citizens of Kansas (as a tax or price increases on energy, or externalized environmental costs). The lack of this information stands is strong contrast to the touted benefits of the project to the developers and one small community and the out-of-state funding partners of the project.

KDHE Response:

Please refer KDHE Responses to Comments C, E, and 37.

KDHE keeps current with all legislation which has the potential to impact the air permitting process. As part of the legislative process, economic assessments are conducted to look at the overall cost versus benefits if the bills were enacted into law, however, economic assessments of proposed legislations are beyond the scope of the air permitting process.

Comment 224:

Increases in ground level ozone, sulfur dioxide and particulate matter from the project, and the resulting health and economic impacts that will be caused are this commenter's concern. "Coals Assault on Human Health," by the Physician's for Social Responsibility reported that exposure to nitrogen oxides can contribute to increased numbers of asthma exacerbations and might be a cause of the development of asthma in the first place. According to the EPA, "breathing air containing ozone can reduce lung function and increase respiratory symptoms, thereby aggravating asthma or other respiratory conditions. Ozone exposure also has been associated with increased susceptibility to respiratory infections; medication used by asthmatics, doctor visits, and emergency department visits, and hospital admissions for individuals with respiratory disease. Ozone exposure also increases the risk of premature death" In 2008, The EPA released the most comprehensive summary of the health effects from particulate matter exposure to date. It found cardiovascular effects and mortality to both be causally related to exposure to particulate matter and respiratory effects to be likely causally related

In 2009, researchers reported that a reduction in exposure to ambient fine-particulate air pollution contributed to significant and measurable improvements in life expectancy in the United States. According to the National Academy of Sciences Report, Hidden Costs of Energy: Unpriced Consequences of Production and Use, air pollutant damages per ton of emissions from coal-fired power plants were on the order of $5,800 per ton for 502, $1,600 per ton for NO_x and $9,500 per ton for $PM_{2.5}$. According to the Sunflower Expansion Project website under this permit Sunflower would be permitted to release 0.06 lb/mmBtu of SO_2, 0.05 lb/mmBtu of NO_N, and 0.012 lb/mmBtu of $PM_{2.5}$ and PM_{10}. Based on comparable projects, a reasonable assumption for the number of mmBtu's burned at the Sunflower Expansion plant each year is 70,000,000. This means Sunflower could be permitted to cause $13 million worth of damage related to SO_2, $2.8 million related to NO_x and $4 million related to PM emissions—a total of $20 million per year in health related damages.

KDHE Response:

Please refer KDHE Responses to Comments F, G, and 39.

Comment 225:

Identifying solutions for the significant health impacts caused by ozone, particulate matter and sulfur dioxide is difficult because they are transboundary pollutants—their points of emission do not necessarily tell you anything about where their effects will occur. As a resident of Kansas City, I am concerned about the inter-geographical inequity inherent in my home being required to meet regulations for pollutants not generated in Kansas City. Kansas City is on the cusp of non-attainment for ozone under current regulation and already experiences spikes in ozone when the Flint Hills is burned or other regional phenomena cause the levels of ozone to dramatically increase

If cities like Kansas City, Wichita and Omaha are designated as non-attainment areas as a result of the increase in ozone and ozone precursor emissions associated with Holcomb and the Holcomb expansion project, the economic and regulatory burdens those cities face will be directly attributable to the benefits enjoyed by Colorado ratepayers and fiscally irresponsible rural electric co-ops.

The EPA's proposed Transport Rule would limit power plant emissions of ozone precursors and sulfur dioxide from over 30 states, reducing the formation of fine particles and ground-level ozone. The EPA expects reductions to begin in 2012, soon after the rule is finalized. But because KDHE will likely be implementing the EPA-promulgated rule, KDHE should consider the cost/benefit analysis for Kansans. Nowhere in the permit application does it address these impending regulations. Reductions will be required by states and, while the Holcomb Expansion Project might be marginally cleaner than existing plants, but what are the consequences for permitting such a large increase in emissions just ahead of new regulations: what will the net increase in emissions mean? What will the geographic distribution of emissions mean for downwind neighbors in your state? What will the increase in emissions mean to other fossil-fueled power plants in Kansas—ones *actually* supplying electricity to Kansans? The modeling required of this project did not attempt to answer any of these questions.

KDHE Response:

Please refer KDHE Responses to Comments and 164.

Comment 226:

The commenter has concerns about being downwind of this plant plus EPA is also reconsidering the ozone level. There is a proposal to reduce the level from 75 parts per billion to as low as 60 parts per billion. Given the health risks associated with ground-level ozone, stricter levels are appropriate...as long as ozone levels specific to a location have a mechanism by which they can be reduced. Permitting this project without requiring that the appropriate modeling consider both the Transport Rule and revision of the ozone level represents nothing less than the tacit approval by KDHE of the willful transfer of both regulatory liability and health burdens from Colorado rate-payers and a fiscally-irresponsible rural electric co-op to those of us downwind of the plant.

The commenter is disappointed that officials elected to serve all Kansans are exerting political influence on KDHE on behalf of those who would pollute this great state and requests that KDHE deny, or at the very least modify, the current Sunflower Electric Power Corporation draft permit.

KDHE Response:

Please refer KDHE Responses to Comments 31 and 32.

Future changes in statutory or regulatory requirements applicable to Holcomb 2 emissions will be required, as necessary.

Comment 227:

A full consideration for cleaner energy sources that can be used for baseload generation like natural gas should be given. The agency should be proactive in looking for alternatives and responsible choices for the Kansas ratepayer in light of the knowledge that pending rules on Hazardous Air Pollutants, Mercury, Particulate Matter and Nitrogen Oxides are a certainty. The Clean Air Act is clear in it's consideration of clean fuels as part of a BACT review. BACT is defined in the Clean Air Act as:
An emission limitation based on the maximum degree of reduction each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems and techniques, including fuel cleaning, **clean fuels,** or treatment or innovative fuel combustion techniques for control of each such pollutant. Air and energy experts agree that natural gas is a cleaner fuel than coal for producing electricity for nitrogen oxides, sulfur dioxide, particulate matter, and other pollutants; therefore, natural gas should be considered as a BACT "clean fuel" requirement for all fossil fuel power plants under review.

KDHE Response:

Please refer KDHE Responses to Comments A, G, and 39.

Future changes in statutory or regulatory requirements applicable to Holcomb 2 emissions will be required, as necessary.

Comment 228

EPA guidance provides that natural gas should be considered as BACT for fossil fuel power plants:

1. The identification of BACT alternatives "is intended to be very broad" and should "promote use of the best control technologies as widely as possible." *Desert Rock Energy Company LLC, PSD Permit AZP 04-01, 2009 EPA App. Lexis 28 (September 24, 2009) and Prairie State Generating Company, PSD Appeal No. 05-05, 2006 EPA App. Lexis* 38 *(August 24, 2006).*

2. All "potentially available" control options must be considered. *Prairie State, at *32; In re Northern Michigan University Ripley Heating Plant, PSD Appeal No. 08-02, 2009 EPA App. LEXIS 5 (Feb. 18, 2009).*

3. The permit issuer must take a **"hard look"** to discern "which design elements are inherent for the applicant's purpose" and which design elements "may be changed to achieve pollutant emissions reductions without disrupting the applicant's **basic business PurPose** for the proposed facility". *Cash Creek Generation, LLC, Petition Nos. IV-2008-1 & IV-*

*2008-2, 2009 EPA CM Title V Lexis 4 (December 15, 2009), at *22. See also, Desert Rock at *121, citing Prairie State slip* op. *at 30;* accord *Northern Michigan University slip op. at 26-27;* accord *In re: American Electric Power Service Corporation, Petition No. VI-2008-01, 2009 EPA CAA Title V LEXIS 11 (December 15, 2009)*

4. The **"basic business purpose"** of a baseload, fossil fuel power plant is to produce electricity that can provide baseload power from a given site. Whether the fuel is coal or natural gas is irrelevant to whether natural gas should at least be considered within the BACT review. The focus in on the product (i.e., baseload electricity) regardless of fuel source. *Hibbing Taconite Company, 1989 EPA App. Lexis 24, 2 E.A.D. 838 (July 19, 1989).*

There several EPA pending rulemakings that will have an impact on coal-fired generation and I would very much regret if Kansans had to bear increased cost for controls on this coal plant because we did not make a cleaner energy decision when we had the opportunity to do so.

KDHE Response:

Please refer KDHE Responses to Comments 38 and 39.

Future changes in statutory or regulatory requirements applicable to Holcomb 2 emissions will be required, as necessary.

Comment 229:

Do our accepted models for projecting particulate and ozone levels for a new power plant accurately reflect the realities that this plant will be operating in the coming years of climate change?

If there is considerable uncertainty in these projections, what should be done to either mitigate these uncertainties or collect data that will help refine those models?

KDHE Response:

The sources referenced in the comment confirm that the various models currently available which attempt to forecast climate change are inadequate to provide valid and reliable temperature or atmospheric predictions. The EPA-approved models used for PSD permit purposes do not look to future weather. EPA documents cited by the commenter reflect that this issue is presently under study but that, as yet, the level of scientific understanding is simply insufficient.

EPA identified that such efforts in the future might yield some useful tool for these purposes. However, the tools now available are insufficient to predict the future. The commenter's underlying concern appears to be that changed conditions in the future but still within the potential useful life of the plant, might indicate the need for different emission limits or controls. Changing requirements for NAAQS, NSPS, and PSD have occurred and have been managed by EPA, KDHE, and the regulated community since the inception of the Clean Air Act.

The commenter further speculates that requiring additional monitoring points to gather data for both weather and emissions would provide more reliable results. Neither KDHE nor EPA has disapproved the protocol Sunflower submitted in advance of the air dispersion modeling it performed as a part of the permit application. KDHE, in consultation with EPA, evaluated the proposed protocol and approved it. The same observations apply to the visibility modeling done by the applicant. KDHE, in consultation with EPA, evaluated the proposed protocol and approved it.

KDHE is required to perform a monitoring network assessment for all criteria pollutants every five years [40 CFR 58.10(d)]. This comprehensive monitoring assessment requirement will continue into the future and should climate variations occur that worsen air quality, additional monitors would be recommended during this required review process. Historically, KDHE has also relocated existing monitors around the state in order to determine the air quality in different areas. Monitor relocations generally occur after the air quality has been assessed in a particular area with no violations. It is possible that monitors would be relocated in close proximity to Sunflower's proposed expansion in the future; in fact in the current five year network review KDHE has proposed placing a new ozone and $PM_{2.5}$ monitor in Garden City. In the case of Sunflower's current permit review, KDHE has determined that pre-construction monitoring would not be required due to the proximity of existing monitors to the proposed source. For visibility monitoring Kansas currently has no Federal Class I areas; thus KDHE does not have specific jurisdiction to monitor for visibility in these Class I areas. KDHE operates two IMPROVE visibility monitors within the state, one in close proximity to Holcomb at Cedar Bluff state park, while the Sac and Fox tribe operates a third visibility monitor within the state. KDHE believes that the existing monitoring network coupled with the five year network review requirements will provide adequate monitoring data to characterize air quality for both standards and modeling inputs. Additional information on the KDHE air monitoring program can be found at http://www.kdheks.gov/bar/air-monitor/indexMon.html.

Comment 230:

The commenter states Sunflower has 30 years of restructured and unpayed taxpayer debts on its current operation and it seems to revolve around getting out from under their existing debs by building their way out. This seems financially risky due to unstable nature of the field – no consensus on cap and trade and carbon emissions policies from EPA or congress, which could have a huge impact on the project's viability.

KDHE Response:

KDHE has no authority regarding this issue and it has no bearing on the PSD permitting process.

Comment 231:

There is no current technology that exists to remove a significant percentage of CO_2 that would be emitted (6.7 million tons/yr at 92% capacity). It will be expensive. How will it be kept out of the atmosphere? Who will foot the bill – federal taxpayer, utility, consumer?

KDHE Response:

Please refer to Response to Comment I.

Comment 232:

The regulatory relationship between Sunflower, the Colorado consumers who will be using the lion's share of electricity and the state of Kansas' oversight of the project is troubling for commenter. Colorado has much stricter regulatory control over power plants than does Kansas. It seems this project skirts this regulatory oversight by going to Kansas where the state legislature removed KDHE completely from oversight on such projects and EPA has been sitting on the sidelines.

KDHE Response:

Please refer to KDHE Response to Comment D.

The BACT process that was utilized to evaluate this project relies upon federal regulations and guidance policies that used by KDHE in evaluating the permit application.

Comment 233:

The power plant will emit mercury, CO_2, consume approximately 3.9 trillion gallons of Ogallala aquifer water per year, which has an unknown impact on agricultural and municipal users in the area.

KDHE Response:

Please refer to KDHE Responses to Comments C, G, and I.

Comment 234:

Commenter says this is short-sighted, with limited benefit arrangement, and sets up a bad precedent for the area. Instead of using homegrown wind and energy we'll be dumping ground for Wyoming coal for Coloradoans overwhelming the wind and solar energy options.

KDHE Response:

Please refer to KDHE Response to Comment 103.

Comment 235:

KDHE already denied Sunflower Power's 2007 application to build a coal fired plant. That decision is binding and controlling on the current application. This permit was denied by the KDHE, based on unacceptable emissions of Carbon Dioxide, a known greenhouse gas.

Sunflower Power has again filed for a permit, with no substantial changes in the character of the plant. KDHE already made these findings in its prior denial of the permit. Based on the prior binding decision of KDHE, Sunflower Power is prevented from reapplying a second time.

In its prior application, which KDHE denied based on carbon dioxide emissions, Sunflower Power Plant appealed to the Kansas Supreme Court, where it is pending. Jurisdiction over the carbon dioxide question and the application for a coal plant lies with the Kansas Supreme Court.

The statutory framework in Kansas, giving effect to the Clean Air Act, is unconstitutional. KDHE cannot grant a permit under an unconstitutional statute. After the denial of Sunflower's 2007 permit application, on May 4, Governor Parkinson and Sunflower Power signed an agreement requiring issuance of a permit for one new 895 MW unit. The agreement was signed into law on May 22. It was brokered with no public knowledge and announced only once it was signed. This makes the statute implementing the Clean Air Act in Kansas unconstitutional, as no longer following the Clean Air Act.

No consideration of IGCC as BACT;

Improper Notice. Under 40 CFR 70.7, states that may be affected must be notified, including contiguous states and those within 50 miles of the source. In the previous application a number of states objected. Eight attorney generals from California to Maine weighed in on the issue and asked the state to at least minimize the damaging global warming gases the plant will spew.

No contested hearing; I would request a hearing which would allow interested parties to conduct pre-hearing discovery, obtain compelled attendance of witnesses, present direct and cross-examination of witnesses, and submit proposed findings of fact and conclusions of law.

KDHE Response:

Please refer to Section KDHE Response to Comment I, 36, and 39.

The commenter raises several issues of law including the doctrine of res judicata, KDHE's jurisdiction, and the constitutionality of the Kansas air quality act. These legal issues should be preserved for appeal.

On the issue of adequacy of public notice, the commenter cites to 40 CFR Part 70.7, which relates to Title V operating permits and is not applicable to PSD permits.

Comment 236:

Was the coal pulverization process and the pollutants that it will be adding to the environment part of the analysis?

KDHE Response:

The coal preparation process is regulated at 40 CFR 60 Subpart Y and is reviewed as part of the BACT process for these material handling systems. The coal crusher is a totally enclosed process in the coal crusher building and the entire coal crusher building is under the control of a dust collection system with an established BACT particulate matter (PM) limit in permit condition 4 on page 12 of the permit. An overall opacity limitation of 10% for any fugitive emissions is further imposed in the Emission Limitation Section 3, page 10.

The SCPC furnace will be equipped with several coal pulverizers. These pulverizers prepare the coal, by crushing to the consistency of talc, for final introduction in the furnace where it is burned. These are totally enclosed (unvented) pieces of equipment, the full contents of which are continuously blown into the furnace. There is no control technology required for this equipment as it is not a source of emissions.

Comment 237:

Kansas is ideally situated In terms of geology and existing related technologies to become the leader in Compressed Air Energy Storage Systems; which are already in operation in Germany and the USA, but not in Kansas. If an amount of power equivalent to the proposed Holcomb plant was provided by wind plants from the great wind resource in the area, supported by Compressed Air Energy Storage (CAES) to produce baseload wind power, the people in southwest Kansas would see even MORE jobs than the jobs from the coal plant.

KDHE Response:

The commenters seek to redefine the source. Energy storage systems for electricity, like compressed air storage (CAES) are usually paired with an energy source to produce the electricity that can then be stored to be utilized when the conventional energy sources are not otherwise present in adequate quantities to meet the load.

One CAES system is installed in the US at Alabama Electric Cooperative's (AEC) McIntosh facility. The off-peak energy, in their case supplied by a coal-fired base load plant, uses a very large (50 MW) air compressor to pump air into a mined salt-dome storage formation. During on-peak periods, the combustion turbine is able to utilize the compressed air stored to produce electricity without operating the compressor, which nominally consumes about 60% of the energy produced by the combustion turbine. That is not free energy, because the stored volume just used must then be replenished, at a lower efficiency, when low-cost energy is available. This CAES has not functioned in a few years, since the base-load coal resource previously used in off-peak hours is now fully subscribed, even during off-peak hours.

The fundamental issue for all energy-storage systems is that in order to be dispatchable, they must depend upon a primary energy source that is available during off-peak hours. To be economical they depend upon off-peak sources of low-cost energy. It may not be possible for wind and CAES to always meet the base-load needs, which it must if it is to replace any other dispatchable resource.

Please refer to KDHE Response to Comment E regarding jobs and the economy.

Comment 238:

What are the monitoring provisions under the permit for the Class I facilities, and is there going to be a monitoring station in Garden City and Holcomb? Who is going to do the monitoring and who is going to pay for it as a result of this two –facility operation that is going to be there?

KDHE Response:

KDHE assumes the comment refers to monitoring in Class I areas, not Class I facilities. The Class I areas that are closest to the proposed H2 site are Great Sand Dunes National Park and the Wichita Mountains Wildlife Refuge. Both Class I areas operate IMPROVE monitoring sites. These sites provide filter based measurements for fine particulate matter as well as speciation for fine particulates. KDHE does not have plans to locate a monitoring site in Holcomb. KDHE's five year plan for the air monitoring network does include a site in the Garden City area.