Missouri Department of Natural Resources
Air Pollution Control Program

Comments and Responses on Associated Electric Cooperative, Inc.
660-MW Pulverized Coal Fired Generating Facility
Norborne, MO

Prevention of Significant Deterioration (PSD)
New Source Review Permit

Project Number 2006-01-066

This document responds to comments made to the PSD draft permit. The Missouri Department of Natural Resources' (MDNR's) Air Pollution Control Program (APCP) responded to comments during the public notice period. The Department appreciates everyone's participation in the public process associated with this project. However, some comments received were in relation to items the Air Pollution Control Program has no authority to change or modify. The Department has not responded to these comments.

In some cases, comments have been summarized, abbreviated, or paraphrased for the sake of clarity or brevity.

The numbers of Special Conditions from the draft permit may have changed. The numbers referenced in the response reflect the final Special Condition numbering.

The following comments were submitted to the Air Pollution Control Program by **the U.S. Environmental Protection Agency.**

Comment 1: We note that “Special Conditions” sections F.1)c), and F.2),e) establish calendar year limits. We recommend that MDNR specify these limits based on a rolling 12-month period and not a calendar year. This will provide reasonable compliance verification and reporting mechanisms for determining compliance during the 12-month period and provide assurance that the limits will be met on a continuous basis.

> **MDNR Response:** These conditions were written on a calendar basis since this is how the modeling was run. However, MDNR believes EPA’s recommendations are valid and therefore will change Special Conditions F.1)c) and F.2)e) from a calendar basis to a 12-month rolling average.

Comment 2 (excerpt): The performance testing and compliance section of the permit is silent on performance testing methods. We encourage MDNR to modify this section by adding explicit requirements for performance testing in the final permit.

> **MDNR Response**: In the past, construction permits have included specific test methods and emission limits as part of the special conditions portion of the permit. Currently, only emission limits are listed in the permits and test methods for compliance purposes are now determined through discussions with representatives of the Compliance Section prior to testing at the installation and in compliance with 10 CSR 10-6.030. This change was instituted to allow for determination of the most appropriate method to demonstrate compliance considering an installation’s specific operating parameters in cases where more than one test method is available. In addition, promulgation of new methods or changes to existing method that occurred between permit issuance and the dates of compliance testing no longer necessitated amending the construction permits. As such, the permit issued by MDNR to AECI will not state specific test methods in the special conditions. Therefore, unless there is promulgation of a new test method for determining emissions changes to the current test method, these methods will be used by AECI to demonstrate compliance with their emission limits.

Comment 3: Special Condition 14.A requires AECI to conduct post-construction ozone monitoring for up to two ozone seasons following commencement of operations. Monitoring the second year is contingent upon measuring an exceedance of the ozone standard during the first year. The modeling report notes that some exceedances of the 1-hr and 8-hr ozone standards were measured during the preconstruction monitoring. Although the PSD regulations do not mandate specific post-construction monitoring, the preconstruction monitoring revealed ozone standard exceedance. Because the standards are based on a three-year average, EPA recommends that post-construction monitoring be conducted for at least 3 full consecutive ozone seasons following commencement of operation to fully assess compliance with NAAQS.

> **MDNR Response:** Special Condition 14.A allows for AECI to discontinue ozone monitoring upon approval of the Air Pollution Control Program director if there are no exceedances of the ozone standards after the first full ozone season. If AECI is allowed to discontinue the post-construction monitoring and exceedances have been monitored, it is the intent of MDNR to place monitors at the site to allow for three years of continuous monitoring.

Comment 4: The record is unclear as how the modeled emission rates were derived or how they relate to the limits set forth in special conditions 1.F.(2). If the modeled emission rates under-represent worst case, particularly for short term averaging periods, the resulting concentration may lead to erroneous conclusions with regard to the significance of AECI’s contributions to the modeled NAAQS and increment violations. We note that the maximum 3-hr SO_2 concentration is just below the increment threshold. We request that the record include a detailed explanation of the derivation of the modeled emission rates and specify AECI’s contribution to all pollutant concentrations of whether the model predicts a NAAQS and/or increment violation.

MDNR Response: First of all, MDNR views the “record” as the complete permitting file. The modeled emission rates for SO_2 were modeled at a worst case of 0.08 lb/MMBtu for a 30-day rolling average. The 3-hr is based on a worst case number taking into account reduced SO_2 control during FGD atomizer change-out. The other limits pertaining to SO_2 are listed under Special Condition 1.G.1).

In general, the modeled emission rates are not any lower than the limits given in the permit. As such, the modeled emission rates represent the worst case emission rates. Please see the modeling memorandums and files for specific information pertaining to the prediction of whether a NAAQS and/or increment violation has taken place.

The following written comments were submitted to the Air Pollution Control Program by **the Interdisciplinary Environmental Clinic at Washington University in St. Louis on behalf of the Ozark Chapter of the Sierra Club (Wash U).** The comments may be paraphrased or excerpts of the comments may be used due to the length of the comments. The original comments along with Associated Electric Cooperative, Inc. (AECI) response may be read in full in the Attachments.

Comment III. MDNR Should Deny the Permit Because Of Unacceptable Contributions to Global Warming

MDNR Response: At this time, carbon dioxide (CO_2) is not a regulated pollutant under the federal Clean Air Act, the Missouri Air Conservation Law, or their implementing regulations. Additionally, under section 643.055, RSMo the State of Missouri cannot implement regulations that are more restrictive than the federal Clean Air Act. At the current time, the Environmental Protection Agency (EPA) does not have any air quality standards to regulate CO_2. Therefore, the State of Missouri does not have the legal authority to include CO_2 as part of the analysis.

Comment IV. MDNR Must Consider Clean Energy Alternatives To The Proposed Norborne Plant.

MDNR Response: Although the Department supports energy efficiency and assists industry in energy efficiency projects through the Energy Center, the Department's rules and regulations to not grant the authority to require these items through the permitting process.

Comment V. The Draft Permit Fails To Fulfill Modeling and BACT Requirements Regarding Fine Particulate Matter ($PM_{2.5}$)

MDNR Response: The EPA has promulgated a National Ambient Air Quality Standards (NAAQS) for particulate matter less 2.5 microns in diameter, $PM_{2.5}$. However, due to the technical uncertainties associated with modeling and monitoring $PM_{2.5}$, EPA has not yet issued regulations on how to implement the new $PM_{2.5}$ NAAQS standards for facilities that are subject to New Source Review (NSR). At this time, no specific $PM_{2.5}$ modeling protocols have been established by EPA. Rather EPA has stated that States may use PM_{10} as a surrogate for $PM_{2.5}$ to determine compliance with PSD permitting requirements.

On December 17, 2004, EPA designated non-attainment areas for $PM_{2.5}$. However, shortly after this, EPA again issued guidance advising states to continue using PM_{10} as a surrogate for determining compliance with the $PM_{2.5}$ NAAQS. Specifically, EPA stated that "[b]ecause we have not promulgated the $PM_{2.5}$ implementation rule, administration of a $PM_{2.5}$ PSD program remains impractical. Accordingly, States should continue to follow the October 23, 1997, guidance for PSD requirements."

Since there are no relevant rules applicable to a new source that require implementation of $PM_{2.5}$ modeling, MDNR used PM_{10} as a surrogate for $PM_{2.5}$. This determination is reiterated by the recent Longleaf decision.[1]

Comment VI. MDNR's Own Modeling Shows That the Norborne Area Is Nonattainment for PM_{10}.

MDNR's Response: The Air Pollution Control Program determined the contribution from AECI's project is less than the significance levels outlined in 10 CSR 10-6.060(11)(D) Table 4, at any of the "violating" receptors. Therefore, AECI's project does not cause or contribute to these existing predicted violations of the NAAQS and PSD Class II PM_{10} increment standard.

Since it was proven that AECI did not have a significant impact to the NAAQS and Increment "violating" receptors it can be deduced that the cause of the violations are the sources within the interactive source inventory that was compiled and used in the modeling analysis. As noted in

[1] Friends of the Chattahoochee, Inc. and Sierra Club, Petitioners, v. Dr. Carol A. Couch, Director, Environmental Protection Division, Georgia Department of Natural Resources, Respondent, and Longleaf Energy Associates, LLC. Intervenor. Docket No.: OSAH-BNR-AQ-0732139-60-Howells. December 18, 2007

the modeling memorandum “occasionally erroneous data may be provided in the emission inventories”, this along with the potential evaluation of receptors in non-ambient air for interactive sources (on-property evaluation) could cause exceedances/violations of the PM_{10} standards that may be dramatically overestimated. Nonattainment designations are based on monitored concentrations within an airshed. The modeled impacts can be utilized to ascertain the need for additional modeling.

Nonetheless, a full analysis of the area would need to be conducted to determine if the area is in danger of monitoring nonattainment for PM_{10}. This study could not totally rely upon the modeling analysis conducted for this project. Further, the more stringent requirements proposed in this comment would only be triggered upon a nonattainment designation of the area by United States Environmental Protection Agency (EPA).

Comment VII. AECI Will Cause Violations of the 24-Hour PSD Increment For PM_{10}.

MDNR Response: See response to previous comment.

Comment VII.B. AECI's PM_{10} Emission Rates for Haul Roads Must Be Corrected

MDNR Response: It has been MDNR's work practice for numerous years to allow emissions from paved haul roads to be calculated using the unpaved haul road equations from AP-42 and then applying a control efficiency for paving and watering. This practice has been repeated through the course of numerous de minimis, minor, and PSD reviews. To the best of MDNR's knowledge, EPA has not commented negatively on any PSD using this work practice. MDNR acknowledges that this methodology is different from how other states might handle calculating haul road emissions. However, MDNR also acknowledges that when it comes to calculating haul road emissions and modeling those emissions, there is a great deal of variation between states.

Wash U. states that an appropriate silt loading number that should have been used was 3.405 g/m^2. They reference exhibit 216 in how that number was derived. This document does not reference where the testing took place, how the testing was conducted, and only shows data from four test dates. Furthermore, MDNR assumes that the ratio column of Table 1 on page 46 of Wash U's comments switches the daily and 1-hour numbers.

The definition of BACT says:

> “. . . If the director determines that technological or economic limitations on the application of measurement methodology to a particular source operation would make the imposition of an emission limitation infeasible, a design, equipment, work practice, operational standard or combination of these may be prescribed instead to require the application of BACT. . . “

It is MDNR's opinion that it is not practical to place an actual emission limitation in the permit for haul road due to the fact it is infeasible for AECI to demonstrate compliance with an emission limit through testing. It is not MDNR's practice to place emission actual emission limit in PSD permits for haul roads or require testing to try and verify emission limits. Furthermore, MDNR has never received comments from EPA asking for such a condition, nor has it seen such a condition in any other PSD permit.

Comment VIII. AECI and MDNR's Modeling Efforts Suffer from Several Other Serious Defects
Comment VIII.A. The Columbia, MO Airport Meteorological Data are Unreliable for Class II Air Dispersion Modeling (excerpt):**:** For air dispersion modeling purposes, airport data are among the least desirable. Problems with location and the general quality of data are the primary concerns. The USEPA, in their Meteorological Monitoring Guidance for Regulatory Modeling Applications, summarizes these concerns about using airport data:

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

MDNR Response: The document from the EPA entitled *Meteorological Monitoring Guidance for Regulatory Modeling Applications* goes on, in Section 6.7, to state that although data meeting more stringent specifications are preferred the use of "airport data continues to be acceptable for use in modeling. In fact observations of cloud cover and ceiling, data traditionally have been provided by manual observation, are only available routinely in airport data; both of these variables are needed to calculate stability class using Turner's method." The meteorological data used for this project is representative and have been consistently applied with respect to nearly all PSD permits issued in Missouri.

Comment VIII.A (excerpt): The use of antiquated airport data was initially used for simpler Gaussian dispersion models such as ISCST, ISCST2 and even ISCST3.

MDNR Response: This statement implies that the observational data collected at National Weather Service sites is inadequate due to instrument exposure, location, and resolution and can not be used for air quality studies. However, the observational data collected at National Weather Service stations are routinely used in climate evaluations and provide real time meteorological conditions for the aviation industry. The siting criteria for instrument exposure, resolution, and accuracy are required to adhere to the standards outlined in the *Federal Meteorological Handbook No. 1*. The data are input into numerical forecast models which serve as a tool for the development of daily weather forecasts. The meteorological models are complex and the observational data that is collected at the National Weather Service sites must be accurate because it is the primary data input. Additionally, as stated above the National Weather Service data contains needed information that can only be found routinely in airport data.

Comment VIII.A (excerpt): As stated above, the Columbia Airport data are not site-specific to the AECI facility. The distance involved (about 75 miles) makes the airport data clearly not site-specific, with numerous land use classifications existing between AECI and the airport. Equally important, however, are the different land uses at AECI and the airport, respectively. The Columbia Airport is comprised of concrete runways, parking lots, passenger terminals, and other structures associated with air travel activities. These surface and building characteristics in turn affect the boundary layer meteorology present at the airport. In addition, landings, takeoffs, and idling of airplanes affect the site-specific conditions at the airport such that the meteorological conditions are not representative of the area surrounding the AECI facility.

MDNR Response: MDNR determined that the Columbia Regional Airport data is representative and appropriate for use in the AERMOD dispersion modeling. Yes, there is a larger distance between the proposed Norborne site and the Columbia Regional Airport than there is between the site and the Kansas City International Airport, which was the original chosen airport. But distance is not the only criteria to consider when choosing a <u>representative</u> airport site. Data is considered representative if its use results in the reconstruction of realistic planetary boundary layer similarity profiles in order to characterize dispersion with the atmosphere. To determine if representative one must also take into account the surrounding landuse at both the airport site and the proposed facility site. These landuse characteristics include: the surface roughness, Albedo and Bowen Ratio. A landuse analysis was conducted by MDNR staff and it was determined that the majority, at least 80 percent, of the surrounding landuse at both the meteorological site and the proposed facility site consisted of grassland and cultivated land and are therefore similar.

As stated in the *AERMOD Implementation Guide* dated October 19, 2007 if the closest National Weather Service station is not representative of the proposed facility site than another National Weather Service station that more closely resembles the facility site may be used. This document also goes on to state that "most airports are located far enough away from the urban center to be considered rural settings." This is the case with the Columbia Regional Airport that has very few surrounding buildings or structures that may impact the meteorological conditions. Furthermore, the meteorological instrumentation located at airport observing stations must adhere to strict siting criteria to ensure that the data is collected in a concise, consistent fashion across the observing network. *NWS1 10-1302* outlines the criteria that must be used when siting instrumentation at airport locations. This criterion outlines specific requirements for each piece of observing equipment each of which are not to be unduly influenced by obstructions, terrain (including concrete runways), or other airport activities that would impact the instrument reading.

40 CFR Part 51 Appendix W, the *Guideline on Air Quality Models* gives states the authority to use representative data from National Weather Service reporting stations, please refer to Section 8.3.1.2. The requirement to collect on-site meteorological data is typically reserved for facilities located in complex terrain or in areas where micro-meteorological impacts are likely.

Comment VIII.A (excerpt, summary): Quality of Meteorological Data that was used

MDNR Response: If it was required of a facility to collect site specific data than the guidelines listed within the EPA document entitled *Meteorological Monitoring Guidance for Regulatory Modeling Applications* would need to be followed. But since it was determined that meteorological data from the Columbia Regional Airport is representative of the facility site than the use of National Weather Surface Data is acceptable. In Appendix W of 40 CFR Part 51 Section 8.3.1.2 of the *Guidelines to Air Quality Models* states "if National Weather Service data are judged to be adequately representative for a particular modeling application, they may be used." Since the use of National Weather Service data is acceptable the methodology used to collect the data is also acceptable.

The *Guidelines to Air Quality Models* document also recommends that modeling applications employing airport data be based on consecutive years of data from the most recent, readily available 5-year period. The Department's Air Pollution Control Program used a 5-year dataset spanning the years of 2001-2005. The most readily available 5-year dataset from the National Climatic Data Center at the time of the permit application was used in the analysis as the guidance document dictates.

Comment VIII.A (excerpt, summary): Concerns of over the number of calm hours, missing data, and wind speeds with in the meteorological data set that was used.

MDNR Response:
<u>Calm Hours</u>
It is true that the AERMOD model does eliminate calm winds from the analysis. As stated in 40 CFR Part 51 Section 8.3.4.1a of the *Guideline for Air Quality Models* "concentrations may become unrealistically large when wind speeds less than 1 m/s are input to the model. Procedures have been developed to prevent the occurrence of overly conservative concentration estimates during periods of calms." The document also goes on to state that this procedure is to disregard hours within the meteorological data that are identified as calm. In essence it assumes the calm hour is an hour of missing data and is treated as below.

<u>Missing Data</u>
Section 8.3.4.2a of 40 CFR Part 51 *Guideline for Air Quality Models* states that AERMOD has been coded to implement the following procedures, "Critical concentrations for 3-, 8-, and 24-hour averages should be calculated by dividing the sum of the hourly concentrations for the period by the number of valid non-missing hours. . . . For Annual averages, the sum of all valid hourly concentrations is divided by the number of non-calm hours during the year." Therefore AERMOD only divides the concentration by the number of hours where meteorological data is available instead of by the total number of hours in the averaging period. As such, the concentration is not artificially lowered by the inclusion of a zero concentration estimate for a calm or missing period, thereby creating a more conservative modeling result.

<u>Wind Speed</u>
As stated in 40 CFR Part 51 Section 8.3.4.1b of the *Guidelines for Air Quality Models* "AERMOD contains algorithms for dealing with low wind speed (near calm) conditions. As a result, AERMOD can produce model estimates for conditions when the wind speed may be less than 1 m/s, but still greater than the instrument threshold." The document goes on to state that if the

AERMET processor detects the wind speed is less than the instrument threshold the hour will be considered calm and no concentration is calculated. Since AERMOD is the recommended model by the EPA and representative National Weather Service data is acceptable for use, MDNR conducted the modeling analysis by the guidelines the AERMOD system was built on.

Comment VIII.A (excerpt): Excluding calm winds from the data base is inappropriate and will significantly decrease modeled concentrations. This is very important for verifying compliance with applicable standards and increments, particularly when the applicant-modeled concentrations are already close to the threshold values. This is a particular concern for the AECI Norborne facility emissions, where, by itself, modeled highest-second-high 24-hour PM_{10} concentrations are already at 26.0 $\mu g/m^3$. This is over 86% of the allowable Class II PSD increment of 30 $\mu g/m^3$ (AECI AIR Quality Modeling Analysis, July 19, 2007, Table 9-1).

> **MDNR Response:** As stated above calm winds are excluded from the AERMOD model to prevent overly conservative concentration estimates. The above referenced number is from the modeling analysis supplied by the company and does not represent the final modeling analysis that was conducted by MDNR. Please note that there is no Missouri or Federal statute or regulation in place to prevent a company from consuming as much of the increment as is available. The increment evaluation that was conducted considered all increment consuming sources since the establishment of the baseline date in August of 1977. It is important to note that increment consumption is likely to be overstated because increment expanding sources were not included in the compliance demonstration.

Comment VIII.A (excerpt): In addition, the ASOS-derived data used by AECI is less than desirable because of its lack of sensitivity in estimating cloud cover:

> While improving the efficiency acquiring weather data, the ASOS system lacks the observational ability of the human observer to spatially integrate some of the weather elements over a large area. Two such elements are ceiling height and opaque cloud cover, which are important in estimating atmospheric stability and mixing height required for applications of several regulatory and non-regulatory dispersion models.

> **MDNR Response:** The Department's Air Pollution Control Program concurs that the ASOS ceilometer measurements are constrained by the limited vertical range of the instrument. The inability of the ceilometer to detect cloud cover above 12,000 feet could impact the height of the mixed layer within the atmosphere. However, EPA document entitled *Analysis of the Affect of ASOS-Derived Meteorological Data on Refined Modeling* compared predicted concentrations from ASOS derived data and observer based data. The results of the study were inconclusive. With the exception of the volume source impacts, the use of the ASOS data result in higher ambient concentration estimates than the observer based data.

> Additionally, as noted in the EPA document entitled *Meteorological Monitoring Guidance for Regulatory Modeling Applications*, cloud cover data is not typically collected at on-site meteorological stations. As such, the guidance document indicates that cloud cover data from a representative National Weather Service site should be used. If MDNR had requested the collection of on-site meteorological data, the cloud cover would have been obtained from the Columbia Regional Airport.

> Lastly, 40 CFR Part 51 Appendix W, *The Guideline on Air Quality Models* states that "five years of representative data should be used when estimating concentrations with an air quality model. Consecutive years from the most recent, readily available 5-year period are preferred. The meteorological data should be adequately representative and may be site specific or from a nearby NWS station. Where professional judgment indicates NWS-collected ASOS (automated surface observing stations) data are inadequate {for cloud cover observations}, the most recent 5 years of NWS data that are observer-based may be considered for use." Staff form the Department's Air Pollution Control Program have reviewed the ASOS cloud cover data from the

Columbia Regional Airport and have determined that the data is “adequately representative” and can be used for regulatory purposes.

Comment VIII.A (excerpt): But the problems with the meteorological data do not end there. The meteorological data used in AECI’s NAAQS and PSD modeling include both surface and upper air data, the latter being stored in the AERMOD profile data file.

MDNR Response: This statement is incorrect. The “profile” data file that is produced during Stage3 AERMET processing does not contain upper air data for use by the AERMOD modeling system. The “profile” data file contains the wind direction, wind speed, temperature, standard deviation of the lateral wind direction, and the standard deviation of the vertical wind speed from a site-specific observation program or from the National Weather Service. The file contains data that is collected at specific heights on meteorological towers. If on-site data is collected, multiple vertical measurements may be reported in the profile data, however, if representative National Weather Service data is used, a single level profile is created and input into the “profile” data file that is created by AERMET.

Comment VIII.A (excerpt): MDNR describes as follows the five years of meteorological data used as input to AERMOD: “The second file contains a vertical profile of winds, temperature, and the standard deviation of the fluctuating components of the wind.” MDNR, Ambient Air Quality Impact Analysis for AECI PSD Modeling, October 10, 2007, p.6. MDNR’s description of the profile data is only partly correct: It describes what should be included in the file. Instead, the data file created by AECI, and used by MDNR, is devoid of both the vertical profile of winds and any measurements of the fluctuating components of wind.

MDNR Response: The creation of the “profile” data file was correctly processed through the AERMET meteorological processor. As noted previously, the “profile” data file does not contain the vertical data that is collected from upper air soundings. The “profile” data file will only contain information pertaining to data collected at varying levels of a meteorological tower or SODAR data. When representative National Weather Service data are used, the fluctuating components of the winds are not calculated because a single level profile is created.

Comment VIII.A (excerpt): Examining MDNR’s profile data, it appears that the “upper air” observations that AECI used are not upper air data at all, but are instead the surface winds measured at 6.7 meters. AECI’s AERMOD profile data contains only one “upper air” profile, and it uses the exact same values as the surface data collected at the Columbia Airport. In other words, the AECI Norborne modeling uses Columbia Airport surface data instead of upper air profile data, thus completely invalidating the upper air transport and dispersion needed to characterize the emissions from AECI’s 500 foot tall main boiler stack. There is no vertical profile (which implies data at more than one level) whatsoever in MDNR’s profile data. What MDNR represents as a vertical profile is actually a horizontal data profile, with only limited data measurements taken solely at 6.7 meters (22 feet).

MDNR Response: Again, the format of the “profile” data file has been misinterpreted. The “profile” data file does not contain the vertical data that is collected from upper air soundings. The “profile” data file contains information pertaining to data collected at varying levels of a meteorological tower or SODAR data. As noted above, if representative National Weather Service data is used, a single level profile is created and input into the “profile” data file that is created by AERMET. As stated in the AERMET User’s Guide, the “data match the last fields in the boundary layer parameter file, except that the temperature is expressed in different units.” Additionally, if representative National Weather Service data are used, the fluctuating components of the winds are not calculated because a single level profile is created. The anemometer height at the Columbia Regional Airport is appropriately contained within the “profile” data file because this is the height at which the data is collected.

It is important to note that upper air data soundings are <u>required</u> in order for AERMET to calculate the planetary boundary layer parameters that are utilized by routines within AERMOD to create vertical profiles of wind direction, wind speed, temperature, vertical potential temperature gradient, vertical turbulence, and lateral turbulence. Please refer to the document entitled *AERMOD: Description of Model Formulation*. AERMET can not calculate variables such as the convective mixing height without data collected from surface and upper air data sites and soundings.

During initial processing of the meteorological data, AERMET requires the user to input rawinsonde (sounding) data in order to determine the vertical structure of the atmosphere. The variables that are extracted from the sounding file include height, pressure, dry bulb temperature, relative humidity, wind speed and wind direction. AERMET will use this information to perform quality assurance checks and also to compute the convective mixing height. Without a morning sounding from an upper air station, AERMET can not calculate the convective mixing height, a required AERMOD input.

Comment VIII.A (excerpt): Furthermore, MDNR's profile data contain no measurements of fluctuating components of the wind. These are measured standard deviations of either wind speed or wind direction, in both the vertical and horizontal planes. These data (along with other parameters such as wind speed, direction and temperature) are necessary to characterize plume dispersion, and must be measured at various vertical levels to give any meaningful depiction of AECI's elevated emission plumes. Instead, MDNR's vertical profile data only contain measurements of wind speed, direction and temperature measured at 22 feet above the ground at an airport 75 miles away-and nothing else. MDNR has invalidated any analysis performed using these data, because the data are unreliable for use in a sophisticated boundary layer characterization model such as AERMOD.

MDNR Response: See responses to previous comments.

AERMET was developed in order to compute the boundary layer parameters that are necessary for the AERMOD interface to estimate the profiles for wind, turbulence and temperature. The data must be representative of the modeling domain and may be obtained from National Weather Service observing stations, such as the one located at the Columbia Regional Airport. The primary surface characteristics that influence the computation of the boundary layer parameters are Albedo, Bowen ratio, and surface roughness. Because these surface characteristics can influence the similarity profiles that are utilized by the dispersion model, AERMOD, the Department's Air Pollution Control Program performed an evaluation of the surface characteristics at the meteorological site and those at the facility site. A direct comparison between the surface characteristics at the meteorological site and those at the surface site was necessary to determine if the differences would significantly impact the overall pollutant concentrations. Differences are evident between the measurement site and the application site, however, these differences were considered in the Department's determination that the Columbia Regional Airport was appropriate for use in this application.

Comment VIII.A (excerpt): To remedy this unacceptable situation, AECI should have collected at least one year of pre-construction meteorological data consistent with USEPA Meteorological Monitoring Guidance for Regulatory Modeling Applications. The pre-construction meteorological data should include both surface and profile measurements up to the effective stack height of the main boiler. Because of this failure, the current Norborne permit application modeling is unacceptable for NAAQs and PSD increment consumption analyses.

MDNR Response: As stated above the use of 'representative' National Weather Service data is all that is required to be used not site specific data. The use of on-site meteorological data has been required in Missouri only when severe terrain conditions or dramatic micro-meteorological conditions are present. The rolling terrain around the AECI Norborne site is not severe and will not cause dramatic micro-meteorological conditions.

Comment VIII.A (excerpt): In fact, this pre-construction monitoring requirement for AECI was previously specified by MDNR:

In addition to establishing PM_{10}, SO_2, and ozone sites, AECI will be required to install a meteorological tower. The EPA-454/R-99-005 document entitled "Meteorological Monitoring Guidance for Regulatory Modeling Applications" provides the minimum data collection requirements for establishment and collection for the meteorological data.

MDNR Response: This quote was taken from the pre-construction monitoring siting letter. It is standard practice at all monitoring stations for MDNR to require that a meteorological tower be installed during the time when pre-construction monitoring is being conducted. The meteorological data is used for culpability determinations in the event the monitoring data reveals existing air quality concerns. These monitoring towers are neither constructed nor calibrated for the use in a refined modeling analysis, and therefore do not produce sufficient data for modeling purposes.

Comment (excerpt, summary): Due to the timeframe of the project AECI should have collected one year of on-site meteorological data.

MDNR Response: When the preconstruction monitoring siting letter, dated July 21, 2005 was sent to AECI, EPA's recommended model for use was still the Industrial Source Complex (ISCST3) model. The AERMOD model did not become the recommended model until November 9, 2005 and was not required for use until November 9, 2006. When the facility first requested preconstruction monitoring the ISCST3 model was to be used and the Kansas City International (KCI) Airport was selected as the meteorological station of choice due to the relative proximity to the proposed site. Preconstruction monitoring started for all pollutants: PM_{10}, SO_2, and ozone, in August 2005. Still 1 year and 3 months before AERMOD was required for use as the recommended model for refined modeling analyses.

Once it became apparent that the length of the application timeframe would extend into late 2006 it was determined that MDNR would require that AECI change to the AERMOD modeling system. Even though EPA granted the states the flexibility to continue with the use of ISCST3 if a project had already been started. With the change to the AERMOD model, and its new parameters and requirements for similarity in the surrounding landuse at both the meteorological site and the facility site the required meteorological data was changed. The Air Program conducted the required landuse analysis surrounding the facility site and compared it to the landuse at both the KCI Airport as well as the Columbia Regional Airport. The Columbia Airport was chosen because it was more representative of the landuse surrounding the proposed Norborne site than the KCI Airport. At this time during the application process the Air Program did not deem it necessary to require AECI to postpone the application any further to requiring a year of on-site meteorological data.

Comment B. Preconstruction Meteorological Monitoring Should Have Been Required:
Comment B (excerpt): MDNR should have stuck to its original position, requiring AECI to collect preconstruction meteorological data for use in permit modeling. The proposed AECI Norborne plant, which will be a major emission source of many harmful air pollutants, should not be assessed for NAAQS and PSD increment compliance using non site-specific meteorological data collected with none of the quality assurances necessary for air modeling data.

Pre-construction meteorological data for projects that trigger PSD review is already being required elsewhere for coal-fired power plants. Two recent projects in Nevada – Granite Fox Power (near Gerlach) and Newmont Nevada (Boulder Valley) – have collected at least one year of pre-construction meteorological data. The data requirements, specific for input to air dispersion modeling for NAAQS and PSD increment analyses, are detailed by the State of Nevada. From the State of Nevada Guidelines: "Current onsite meteorological data are required for input to dispersion models used for analyzing the potential impacts from the air pollution sources at the facility."

Even municipal air regulatory agencies have been requiring pre-construction meteorological data for many years. As part of their PSD program, the Santa Barbara County (California) Air Pollution Control District requires at least one year of site-specific pre-construction air quality and meteorological monitoring. The meteorological monitoring requirements are specified in a detailed protocol that implements its PSD Rule.212 PSD sources in Santa Barbara County must collect site-specific hourly-averaged values for the following meteorological parameters:

• Horizontal wind speed and wind direction (both arithmetic and resultant)

• Horizontal wind direction standard deviation (sigma-theta)

• Standard deviation of wind speed normal to resultant wind direction (sigma-v)

• Vertical wind speed

• Vertical wind speed standard deviation (sigma-w)

• Standard deviation of the vertical wind direction (sigma-phi)

• Ambient air temperature

• Shelter temperature213

The AECI air emissions are enormous and are released in a complex arrangement of point, area, and volume sources. Using an antiquated, low-quality, and non site-specific meteorological data set, for no other reason than to expedite the permitting process for the applicant, invalidates the entire air quality impact analysis. The permit application should be denied because of this poor modeling practice, and not resumed until AECI has collected at least one year of site-specific meteorological data consistent with USEPA's Meteorological Monitoring Guidance for Regulatory Modeling Applications.

> **MDNR Response:** See responses to previous comments on the acceptability of using National Weather Service data. Please note that each state has its own set of statues and regulations that it must follow. So what may be a requirement for facilities permitting in other states may not be required for facilities permitting in the State of Missouri. Missouri, like many other states, does not require the use of on-site meteorological data at this time.

Comment C. MDNR Scrutinized Meteorological Data Only When it was to AECI's Benefit.
Comment C (excerpt): MDNR provides virtually no data quality analysis regarding its Class II modeling meteorological data. As far as we can tell, it did nothing to determine whether the data were biasing the modeling to under-predict air concentrations. On the other hand, MDNR revisited the Class I modeling each and every time a significant impact was predicted by the CALPUFF model.

This "data shopping" is disingenuous when it is proposed by the applicant; it is wholly inappropriate when accepted or encouraged by the regulatory agency. AECI and MDNR never investigated whether the modeled air concentrations that are slightly below the significance threshold are somehow under-predicted by the choice of meteorological data (or model options).

For example, MDNR tabulated a list of the days when Class I modeling extinction coefficients are greater than five percent (the Air Quality Related Value (AQRV) for this parameter), and then closely examined the conditions that were present during those periods. There is only one purpose for this type of analysis – to modify the modeling results to indicate the project can be permitted as is, without additional emission controls. In essence, MDNR cherry-picked the Class I modeling meteorological data, while ignoring enormous problems in using Columbia, Missouri data for the NAAQS and PSD Class II analyses.

> **MDNR Response:**10 CSR 6.060 Appendix F and 10 CSR 6.060 Appendix H, require the Department's Air Pollution Control Program to follow the modeling guidelines established in 40 CFR Part 51 Appendix W and those established by the Federal Land Manager. The contention that the Department's Air Pollution Control Program was "data shopping" in an effort to permit the project is erroneous. The procedures that were followed in determining compliance with the air quality standards within the Class I and Class II areas follow current air quality modeling guidelines.
>
> The Class I area, Hercules Glades Wildlife Refuge is located more than 250 kilometers from the proposed AECI facility site. Because the distance from the source to the Class I area was large, the Federal Land Manager agreed that the source could perform a screening analysis to determine what, if any, air quality impacts would occur within the Class I area. It should be noted

the Class II modeling analysis and Class I screening analyses are conducted using the same meteorological datasets. Screening analysis is often performed as an initial test to determine if additional, more refined analyses are needed. Screening analyses are conservative and often over-estimate the impact that would be expected to occur, refer to the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* which states "The screening analysis is meant to be easy to conduct and to provide a worst-case maximum impact estimate. If the results of the screening analysis show compliance with existing regulatory requirements, then no further modeling for compliance with standards and increment is required." Because AECI could not show compliance using screening tools, a refined air quality study was required as dictated by modeling guidelines. Refined analyses are meant to more accurately depict ambient concentrations and utilize a more robust meteorological database whose inputs are the result of three-dimensional wind fields (MM5) and meteorological weather observations taken at several National Weather Service observing stations. If the refined analysis indicates potential adverse impact on visibility will occur, the Federal Land Manager will review the magnitude, frequency, and duration of the event. This type of review is only conducted for Class I analyses. The refined meteorological dataset included the most currently available three-dimensional wind field data generated by the MM5 model. Therefore, the most representative data was simulated for both the Class I and Class II analyses.

A distinction must also be made between a Class II and Class I modeling analyses. As stated previously they use two different sets of meteorological data, a different model (AERMOD vs. CALPUFF), and are compared to different standards. It is inappropriate to compare the two analyses and meteorological data used.

Additionally, as noted previously, the meteorological data employed in the Class II AERMOD analysis follows current air quality modeling guidelines and was collected according the *Federal Meteorological Handbook No. 1*

Comment D. MDNR Should Require an Equitable Analysis of Weather Events for Visibility Impairment.
Comment D (excerpt): MDNR should assess the periods when extinction coefficients are between two and five percent, and then perform alternative analyses to verify whether any of the impacts are in fact above the AQRVs. To do otherwise creates a biased and result-driven modeling analysis, which cannot verify compliance with the applicable standards and thresholds. Since MDNR reanalyzes all conditions above the AQRVs, this is necessary to help make the permitting process complete and equitable.

MDNR Response: The document entitled *Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I* report details the steps for conducting a Class I analysis. Within this document it states that "the FLMs are concerned about situations where a change in extinction from new source growth is greater than 5% as compared against natural condition." This document does not require or include any guidance on how to conduct an analysis on lower percent extinction changes.

Comment E. MDNR Ignored Significant AQRV Impacts.
Comment E (excerpt): Beyond reanalyzing impacts in an effort to show that AECI's impacts are acceptable, MDNR ignored significant impacts that is could not eliminate by remodeling. For example, MDNR analyzed total sulfur deposition rates for AECI Norborne, stating: "The worst case annual impact occurred during the 2001 meteorological period with a maximum concentration (sic) of 5.379E-03 kg/ha/yr." MDNR, Class I Ambient Air Quality Impact Analysis for AECI, October 10, 2007, p. 8. MDNR acknowledged that this level exceeds the significance threshold, and recommended that the Federal Land Manager (FLM) should be contacted to see if further analysis is needed. MDNR, Class I Ambient Air Quality Impact Analysis for AECI, October 10, 2007, p. 9. This significant impact, however, did not factor into MDNR's decision to issue AECI's draft permit.

MDNR Response: As stated in the 40 CFR 52.21(p) of the Clean Air Act the permitting authority is only required to notify the Federal Land Manager in charge of the affected Class I area. "Such notification shall include an analysis of the proposed source's anticipated impact" along with the materials used to make the determination. It is the responsibility of the Federal Land Manager to determine "whether a proposed source or modification will have an adverse impact" on the Class I area. If the Federal Land Manager determines there is an adverse impact on the Class I area then they would inform the permitting authority to require a more in depth analysis. No comments were received from the Federal Land Manager, and as such, no action was taken.

Comment E (excerpt): Furthermore, in tabulating AECI's sulfur deposition impacts, MDNR compared the predicted deposition rate of 5.379E-03 kg/ha/yr to the FLM significance level of 5.000E-03 kg/ha/yr, stating that it is below the threshold level. MDNR, Class I Ambient Air Quality Impact Analysis for AECI, October 10, 2007, Table 6. It is unclear whether this is a typographical error or revised interpretation of the FLM significance thresholds by MDNR.

MDNR Response: MDNR acknowledges the typographical error in the Class I modeling memorandum table and will make the appropriate change.

Comments E (excerpt, summarized): MDNR ignored the visibility impacts from the proposed facility on Class II areas.

MDNR Response: The Air Pollution Control Program agrees that the visibility impacts exceed the Class I thresholds outlined in the VISCREEN document. However, there are no regulatory mechanisms in place at the Federal or State level to address this type of impact on Class II areas through permit denial or additional control for visibility impairing pollutants. The reason for the use of the Class I thresholds in the evaluation is there is no guidance for visibility impacts on Class II areas. Also, this evaluation is designed to inform the affected community of possible visibility impacts.

Comment F. AECI's NO_x and SO_x Emission Cause Significant Synergistic Impacts to Plants.
Comment F (excerpt): AECI performed an Additional Impacts Analysis ("AIA") which includes soils, vegetation, and Class II area visibility impacts. In its AIA, short-term (one –hour) air concentrations of SO2 and NO2 caused by the proposed Norborne plant are predicted to exceed the levels that can cause synergistic impacts to plants (AIA, Table 5-4). This concern is heightened because the predicted synergistic impacts exceed the threshold concentrations by roughly a factor of three.

In the AIA, AECI modeled one-hour SO_2 emission rates of 8,950 pounds/hour, which represents the level during spray dryer maintenance and repairs, including atomizer change-outs. AIA, Table 5-1. These uncontrolled emissions can be expected to occur for periods of at least two hours, and perhaps as long as three hours. Given that the synergistic adverse SO_2 and NO_2 impacts to plants occur with as little as one hour of exposure, it is appropriate to include these uncontrolled emission rates in the AIA.

MDNR Response: These paragraphs were based upon the analysis conducted by the company, AECI, and in no way reflects the findings of the final modeling analyses conducted by MDNR.

Comment F (excerpts): MDNR, however, did not model the peak SO_2 emissions that will occur during the FGD maintenance and atomizer replacement. Instead, it modeled three-hour SO_2 emission rates based on the three hour permit limit of 1134 pounds per hour. This permit limit does not include any of the much higher uncontrolled emissions that will occur on a routine basis during atomizer changeout.

MDNR Response: MDNR agrees that the 3-hour SO_2 emission rate that was modeled was based on the 3-hour permit limit of 1134 pounds per hour. MDNR does not agree with the statement that this number does not include the emissions that occur on a routine basis during FGD maintenance and atomizer replacement. As stated this maintenance and atomizer change out occurs on a routine basis which would place it in the category of normal operating conditions not under the malfunction category. The 3-hour SO_2 permit limit applies to normal operating conditions, which is inclusive of startup and shutdown. Therefore AECI will have to meet the 3-

hour limit of 1134 pounds per hour during the FGD maintenance and atomizer replacement. Since this 3-hour number is incorporated into a permit condition, that AECI must meet, the controlled SO_2 emission rate is a valid number to use in the modeling analysis.

Comment G. MDNR's Class I Area Visibility Modeling Fails to Include Short-Term Emission Rates
Comment G (excerpt): MDNR prepared Class I area visibility analyses using annual average NO_x emissions from the main boiler. MDNR, Class I Ambient Air Quality Impact Analysis for AECI, October 10, 2007, p. 8. This approach, however, is inconsistent with FLM requirements to assess visibility impacts using short-term emissions for all pollutants. MDNR, Class I Ambient Air Quality Impact Analysis for AECI, October 10, 2007, p. 8. Rather than re-run the analysis, MDNR scaled the change in background extinction predicted using annual NO_x emissions from the main boiler, by a factor of 721.56/350.48. This represents the ratio of the peak one-hour NO_x emissions from the main boiler to the annual average emissions (in pounds/hour).

MDNR has not explained the validity of this linear scaling approach, and should verify this assumption by remodeling the visibility impacts using the one-hour NO_x emission rate for the main boiler. Furthermore, MDNR's Class I visibility analysis failed to include the peak uncontrolled SO_2 emission rates that will occur during FGD maintenance and repair of the atomizers. Instead, the analysis used controlled SO_2 emission rates, and therefore neglected to assess the Class I visibility impacts during routine maintenance conditions. MDNR must redo its Class I visibility analysis using both short-term NO_x and SO_2 emission rates. MDNR's current analysis is incomplete and unreliable for verifying visibility impacts in the Hercules Glade Class I area.

MDNR Response: MDNR agrees to re-conduct the Class I Visibility analysis using the short-term emission rate for NO_x. Please refer to previous comment with concerns for controlled SO_2 emission rate.

Through the course of reviewing the material it was determined a mistake occurred while running the Class I modeling analysis. This mistake, outlined below, was changed in conjunction with the above comment and the Class I memorandum has been updated accordingly.

It was pointed out by the Federal Land Manager that during the particulate (PM) speciation process not all of the sulfate (SO_4) emissions were included. This was corrected and the results are outlined in the updated Class I memorandum.

Comment IX. BACT Defects Affecting Multiple Pollutants.
Comment IX.A. MDNR's BACT Limits Are Flawed Because They Exempt AECI from Compliance with Several NO_x, SO_2, And PM_{10} Emission Limits during Startup and Shutdown.
Comment IX.A.1: Because the Clean Air Act Requires BACT Limits to Apply Continuously, Startup and Shutdown Must be Included in all BACT Limits.

MDNR Response: MDNR has included a ton per year cap inclusive of startup and shutdown for the following pollutants: NO_x, SO_2, and total PM_{10}. (As a side note, based on EPA comments, this limit will be changed to a 12-month rolling average basis instead of a calendar year basis.) By including a ton per 12-month rolling average cap inclusive of startup and shutdown, MDNR will ensure that AECI will continuously minimize emissions while the boiler is operating.

NO_x, SO_2, and total PM_{10} are the pollutants that are most affected by startup and shutdown events. In the case of NO_x, AECI has given actual data on W.A. Parish Units 5 through 8 showing that emissions during startup and shutdown conditions can exceed the 30-day emission limits given in the permit. The W.A Parish units are achieving the lowest 30-day emission rates in the country. Rather than set a higher 30-day rolling average BACT limit that is inclusive of startup and shutdown operations, using this data partially as the basis, MDNR has chosen to set a lower 30-day rolling average BACT limit and cap the total amount of emissions that can be emitted in a year's time. This ensures that AECI minimizes the amount of time taken during startup and shutdown events when control equipment is coming on-line and emissions might exceed the shorter term limits. All other limits for the main boiler are inclusive of start-up and shutdown.

Please note that AECI will also have to comply with the state regulations for start-up, shutdown and malfunction conditions as stated under 10 CSR 10-6.050. In the event of a malfunction , start-up or shutdown which results in excess emissions that exceed one hour, the facility is required to notify the MDNR's Air Pollution Control Program. This submittal will be used by the director to determine whether the excess emissions were due to a start-up, shutdown or malfunction condition. These determinations will be used in deciding whether or not enforcement action is appropriate.

Comments IX.B: MDNR's BACT analysis is flawed because it fails to consider integrated gasification combined cycle ("IGCC").

Comment (summarized): Washington University argues that integrated gasification combined cycle (IGCC) should have been considered in the BACT analysis and that AECI's "white paper" is not substitute for a legally mandated BACT analysis.

MDNR Response: The BACT analysis is meant to be a source-specific analysis. The Environmental Appeals Board describes this BACT analysis as follows:

> [P]ermit conditions are imposed for the purpose of ensuring that the proposed source…uses emission control systems that represent BACT….These control systems, as stated in the definition of BACT, may require application of "production processes and available methods systems, and techniques…." to control the emissions….*The permit conditions that define these systems are imposed on the source as the applicant has defined it…*

The PSD permit application submitted by AECI, and reviewed by MDNR, was for a pulverized coal-fired boiler. The Draft NSR Workshop Manual at B.13 gives the following guidance:

> Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives. For example applicants proposing to construct a coal-fired electric generator have not been required by EPA as apart of a BACT analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting per unit product (in this case electricity). However, this is an aspect of the PSD permitting process in which states have the discretion to engage in a broader analysis if they so desire. Thus, a gas turbine normally would not be included in the list of control alternatives for a coal-fired boiler.

IGCC power plants and pulverized coal-fired power plants are separate and distinct types of power generation facilities[2]. It is the Department's position that requiring AECI to evaluate IGCC would constitute redefining the source. The Department believes that for the State of Missouri BACT requirements are not a channel to redefine the source. Thus, the Department did not require AECI to consider IGCC as part of their BACT analysis.

This decision is consistent with the Department's review in the Kansas City Power & Light Iatan's and City Utilities of Springfield's PSD New Source Permits. This determination is also reiterated by the recent Longleaf decision.[3]

Comment X.A: AECI and MDNR Made Fatal Errors in Conducting Their BACT Analyses

Comment X.A.1: AECI and MDNR Purported to Follow the Top-Down Process

MDNR Response: MDNR uses the "top down" process and the New Source Review (NSR) Workshop Manual as a guideline and resource when determining BACT limits; however, it is not

[2] Friends of the Chattahoochee, Inc. and Sierra Club, Petitioners, v. Dr. Carol A. Couch, Director, Environmental Protection Division, Georgia Department of Natural Resources, Respondent, and Longleaf Energy Associates, LLC. Intervenor. Docket No.: OSAH-BNR-AQ-0732139-60-Howells. December 18, 2007

[3] Id.

Department policy to strictly follow the Manual. MDNR retains its right to interpret the NSR rules and implement them in a lawful and competent manner.

Comment X.A.2: The BACT Analysis Contains a Number of Generic Flaws That Apply to All Pollutants Considered.
Comment X.A.2.i: BACT Limits Not, In Fact, Lowest Achievable
Comment X.A.2.ii: BACT Limits Not Based on Maximum Degree of Reduction

MDNR Response: The NSR manual states that

> "a permit requiring the application of a certain technology or emission limit to be achieved for such technology <u>usually</u> is sufficient justification to <u>assume</u> the technical feasibility of that technology or emission limit." [Emphasis added]

The assumption here is that BACT analysis performed by those companies and permitting authorities were done correctly and/or was conducted being completely aware of all pertinent documents, studies, data and technical issues. Applications, including BACT analysis, are reviewed on a case-by-case basis. Emission limits established in other permit are part of what goes into a BACT review. However, there is other information that can, and should be, considered. If a company such as AECI brings up a relevant information that other companies or permitting agencies may not have considered which gives a sufficient reason for granting a higher limit than those previously permitted, then MDNR believes that a higher limit may be justified, especially when there is lack of actual data that can demonstrate that a facility can continuously comply with a certain limit. The lack of actual data can be a valid reason for permitting authority having discretion to allow for a higher limit.

It is generally accepted that a permit emission limit should be set at a level greater than a rate that can be achieved periodically to account for operational variability, including varying coal quality, long term performance of the plant as well as the control equipment, and measurement uncertainty. According to the Environmental Appeals Board, BACT does not require that the emission limit to reflect the highest possible control efficiency, but instead one that "will allow the permittee to achieve compliance consistently." The EAB has also said that "[i]t is customary to establish emission limitations based on realistic operating parameters, rather than on results that are only occasionally achievable" such as those based on a one-time performance test.

A BACT emission limit must be based on "the maximum degree of reduction of each pollutant". However, there is no strict requirement that the maximum degree of reduction must be analyzed on a percent reduction basis. BACT determinations for several pollutants have been made by basing the emission rate limit on the lowest emission rates known to be achievable and/or permitted along with consideration of the equipment's capabilities.

Comment X.A.2.iii (excerpts): "The draft permit sets normal operation BACT limits for the PC boilers in pounds per million Btus [British Thermal Units} ("lb/MMBtu") and separate limits in lb/hr or ton/yr, but these are not identified as BACT limits. This is not sufficient to ensure that the BACT limits are enforceable, will be met continuously, and will protect ambient air quality standards and increments."

MDNR Response: All limits set forth in the draft permit will have to be complied with regardless whether they have been designated as a BACT limit or not. Those limits that have been designated as BACT were derived through the BACT analysis. Other limits were put in the permit to ensure compliance with modeling standards.

BACT limits given in a lb/MMBtu basis can be converted to a lb/hr basis by multiplying the lb/MMBtu limit by the maximum heat input of 6,872 MMBtu/hr. The Department does not feel that it is necessary to state the limits in terms of both lb/MMBtu and lb/hr.

Comment X.A.2.iii (excerpts): "The BACT limits for the PC boiler should be expressed in units of pounds per megawatt-hour of electricity output, in lieu of lb/MMBtu, to foster lower emissions through more efficient operation, a concept consistent with the definition of BACT."

MDNR Response: The majority of limits established by permitting agencies for coal-fired plants have been expressed in units of lb/MMBtu. The usage of these units, lb/MMBtu, allows for direct comparison with these other units. Since emissions are directly related to the amount of coal burned (i.e. heat input) and not the electricity output, the Department feels that the BACT limits in terms of lb/MMBtu are more appropriate.

Comment X.B: The Stated BACT Limits for NO_x Emissions from the Main Boiler Do Not Reflect BACT.
Comment X.B.1: The NO_x BACT analysis fails to properly address in-boiler controls throughout the top-down process.
Comment X.B.1.i (excerpts): "AECI fails to identify combinations of controls as well as some types of combustion controls….In the case of OFA, the corresponding performance level would be determined by which configuration of OFA is used….. The BACT analysis fails to specify which of the three OFA systems it will be using."

MDNR Response: MDNR conducted a comprehensive review of NO_x combustion control technologies based on technical publications, information from recently permitted and proposed coal-fired boilers, the RBLC and EPA's Modified Coal-Fired Utility Summary Spreadsheet. On pages 32 through 33 of the permit, MDNR gave an overview of the NO_x combustion controls it considered. Based on this analysis, MDNR deemed that the installation of low NO_x burners (LNB) and Overfire AIR (OFA) should be required for the control of NO_x emissions from the boiler. There were no other combustion controls or combination of combustion controls that were found to have a higher control efficiency. Since the top combustion control were chosen, MDNR did not include extensive analysis of other combustion controls or combination of controls in its BACT write-up. This BACT determination is consistent with top controls chosen by other recently proposed or permitted boilers.

OFA is an inherent part of the boiler design. By specifying the OFA configuration, the most efficient design of the boiler with the least emissions impact may be compromised because of a designers' inability to use other configurations. For example, if the OFA ports are not optimally located, excess CO may result with minimal reduction of NO_x. Furthermore, MDNR has not found any other permits where OFA configurations are specified.

Comment X.B.1.ii (excerpts). Use of an inappropriately high outlet rate from the boiler has resulted in NO_x emission limits that are not BACT…. The proposed boiler outlet of 0.35 lb/MMBtu is not credible for a new supercritical boiler equipped with LNB and staged OFA…. Although the record indicates that MDNR investigated boiler outlet rates of top performing facilities, MDNR failed to select a boiler outlet rate that is reflective of the maximum degree of reduction achievable.

MDNR Response: Once MDNR identified LNBs and OFA as the top combustion control, MDNR looked closely at the NO_x rates that could be achieved by the addition of LNBs and OFA to the proposed boiler.

To directly address the comment above, the MDNR does not view the boiler outlet of 0.35 lb/mmBtu as being a BACT rate. The NO_x rates stated as BACT in the permit considers the combination of LNB with OFA **and** the SCR, not just LNB with OFA.

The rate of 0.35 lb/MMBtu was given by AECI as one that would cover all normal operating conditions on an on-going basis including load changes and low-load operations of approximately 35%. In AECI's BACT analysis, they also state that typical operation of the boiler would have an expected rate of approximately 0.2 lb/MMBtu. Using EPA's Clean Air Markets website, MDNR queried all dry bottom boilers operating with LNBs and OFA only and found that the average of 87 units was 0.34 lb/MMBtu on an annual basis. Further analysis of the top 25% units showed high variability of monthly averages during the course of the year. The reasons for this variability are difficult to gather from the data. Close to half of these top performers exceeded monthly rates of 0.30 lb/MMBtu. MDNR concluded from this analysis that although the proposed rate by AECI is not the lowest rate being achieved by other boilers with the same combustion controls, it is within the range of operation.

During the course of the technical review, MDNR had several concerns with setting a specific inlet NO_x concentration into the SCR and a specific SCR removal efficiency. Some of the major concerns included the following:

- The effects of lower inlet concentrations into the SCR and the capability by the SCR to maintain a high removal efficiency at these lower concentrations;
- Catalyst lifetime of the SCR catalyst using PRB coal and ability to maintain a high removal efficiency over years of operation;
- Comparing removal efficiencies of ozone season-only operated SCRs versus year-round. (Ozone-season-only units were used in many technical publications to demonstrate SCR performance.)

In light of these uncertainties, MDNR decided to put more emphasis on NO_x BACT emission rates that demonstrated what the combustion controls and post-combustion controls could achieve together versus what each of the individual components are capable of on their own. MDNR verified that the individual components were within the top range of operation of other similar boilers, but considerations of combined controls were ultimately used to set the limits.

Comment X.B.2. The BACT analysis fails to consider an SCR control efficiency that is reflective of the maximum degree of reduction.
Comment X.B.2.i. . Lower SCR control efficiencies have been guaranteed and achieved.

MDNR Response: Wash U states in their comments that "The NO_x BACT analysis does not include any performance data or degree of reduction data, required to prepare Step 3 rankings, and thus is fundamentally flawed." All potential post-combustion NO_x control technologies were identified and an evaluation of each of the control technologies was conducted. Infeasible options were eliminated. See the BACT analysis of the permit on pages 32 through 35, as well as in AECI's BACT analysis. The remaining control technologies were ranked in order of effectiveness (See Table 4 of the permit). SCRs were identified as the top post-combustion control and thus selected as BACT control for NO_x. Further evaluation of other technologies was not conducted since the top control was chosen.

Wash U comments that "modern SCRs routinely achieve NO_x removal efficiencies greater than 90%"and cited several sources that support their claim. Many of these sources (Ex. 59 Erickson and Staudt, Ex. 50 and Ex. 60 Srivastave et al., Ex 60 Ken Wicker and Jim Staudt, Ex. 66 "utility E-Alert #798) provide information stating the units are achieving 90% removal, but in many cases the information is general and/or based on ozone-season operated units. MDNR is not convinced that inlet loading to the SCR does not play a role in achievable removable efficiencies nor is MDNR convinced that performance of ozone-season operated SCRs can be directly compared to year-round operation. Many reasons for these doubts are stated in the same sources cited by Wash U. In the article by Ken Wicker and Jim Stuadt (Wash U. Ex. 60), they state that "Today's SCR systems are designed to achieve about 90% NO_x removal and very low ammonia slip rates…But those designs leave little room for error. Three areas in particular that have proven essential for maintaining top SCR performance are ammonia distribution, catalyst maintenance, and catalyst management". In a presentation by James E. Staudt and Clayton Erickson (Wash U. Ex. 63), one conclusion reached of their study is "Ozone season variability [is] greater than year round possibly due to increased removal efficiency".

MDNR found very little actual performance data on SCR performance for year-round operated units. Units are only required to report SCR outlet NOx emissions for the Clean Air Market database and therefore there is no data on inlet SCR rates except for those units that operate only during the ozone season. Wash U asserts that "vendor experience lists indicate that SCRs are routinely designed to achieve 90% NOx control". MDNR compared this list to data gathered during MDNR's technical review from the Clean Air Market database comparing 2005 1st quarter to 3rd quarter NOx rates for ozone seasons. Of the 10 units which MDNR had data on, only 3 achieved the 90% design performance level as stated in the vendor list. The other 7 units had actual NOx removal rates ranging from 77.1% to 88%. Therefore, although the vendor lists will show what SCRs are designed for, it does not necessarily mean that they are achieving those efficiencies.

With regards to 93% NOx removal efficiency for the SCR at AECI's New Madrid plant, the inlet NO_x loading to the SCR is 1.5 lb/MMBtu with a 3 ppm ammonia slip which is considerably higher than the baseline inlet NO_x loading of 0.35 lb/MMBtu proposed by AECI. According to article by Oliva and Khan (Wash U. Ex. 67), "the average SCR effectiveness will be influenced by several factors, including the SCR design efficiency, *the uncontrolled NO_x level of each source at the SCR inlet*, the required controlled NO_x level at the stack for each source, and the level of SCR operation selected by each source, which may be affected by economic considerations associated with the cap and trade program under which these SCR installation operate" [italics added]. This article suggests that a system with a higher inlet NO_x loading is more capable of achieving higher removal efficiencies.

When setting a BACT limit, the U.S. EPA's Environmental Appeals Board (EAB) has stated that "permitting agencies have the discretion to set BACT limits that do not necessarily reflect the highest possible control efficiencies but, rather, will allow permittees to achieve compliance on a consistent basis." [*Three Mountain Power* at 21, citing *In re Masonite Corp*., 5 E.A.D 551, 560-61 (EAB 1994)]. Because of MDNR's uncertainties stated in this response and the response to Comment X.B.1.ii, MDNR chose to set the BACT limit based on what MDNR thought was continuously achievable. This was determined by analyzing actual performance of existing systems as well as considering the levels that were being permitted or proposed for similar type boilers.

As a side note, in reference 351 of their comments, Wash U applies a ratio between the maximum 30-day and maximum annual inlet rates of six plants to a 30-day rolling average to calculate an "equivalent" annual average for inlet NO_x rates into the SCR. MDNR believes that this method as established in Wash U's Ex. 55 is not a valid basis for estimating an "equivalent" averaging period nor is it valid in setting a BACT NO_x limit that is supposed to be conducted on a case-by-case basis. As pointed out in Wash U's Ex. 59, there are high and low levels of variability in outlet NO_x emissions for units equipped with combustion controls as well as units with combustion controls and SCRs. To take data from a small sample of units' data (Wash U. chose to use the Labadie and Rush Island plants – 6 units total), average it, and present it as a universal ratio can be misrepresentative. In Wash U's Ex. 55, the ratio of maximum 30-day rolling average to maximum 365-day rolling average ranged from 0.78 to 0.91 for the sample of units. The level of variability in boiler operation will depend on many things including changes in load and operating practices (Wash U's Ex 59). As stated in other comments, MDNR believes when setting the BACT NO_x limit more weight should be given to achievable outlet rates rather than assigning a percent reduction to an inlet NO_x rate.

Comment X.B.2.ii. Inlet NO_x levels do not constrain achievable SCR NO_x control efficiency.

MDNR Response: MDNR partially responded to this comment in the discussion above. However, there were several specific comments made in this section by Wash U that merit a response.

Wash U state the MDNR wrongly made the assertion that removal efficiency by the SCR is constrained by inlet NO_x levels. To support their argument they quoted an article by Erickson and Staudt (Wash U, Ex. 59) that states that "SCR systems on PRB fired units [low inlet NO_x] have no greater control or reliability issues compared to bituminous [high inlet NO_x] coals". The bracketed portions were added by Wash U. Upon further review of this article it is clear that the authors do not associate high or low NO_x inlet levels with a certain type of coal. Nor are they saying that a certain type of coal is capable of greater removal efficiencies than another. In fact, they are simply saying that PRB coal seem to be just as reliable (capable of maintaining a steady performance) as other types of coal and that "SCR systems on bituminous fired units can attain, with high removal efficiencies, outlet NOx emission limits in the same range or better than PRB units with combustion NOx control systems." Although there is some concern that SCR units on boiler systems firing PRB coal may affect NO_x removal on a long-term basis due to poisoning of the catalyst, MDNR does not attribute the type coal as a reason for low NO_x inlet rates into the SCR. The reason for low NO_x inlet rates is attributed to the performance of combustion controls.

When designing the SCR system, AECI will have to take into account the full range of NO_x inlet concentrations that could occur during operation of the boiler (from low loads to full loads) to ensure compliance with the NO_x emission limits. This will include designing for relatively low inlet NO_x concentrations as opposed to many other units that do not have the level of combustion controls that AECI will be required to have.

Comment X.B.2.ii (excerpt): "Further evidence that high SCR removal efficiencies can be achieved with low inlet rates is shown by the example of gas-fired power plants, whose inlet NOx emissions are an order of magnitude lower than coal-fired power plants….[I]t is misleading to claim that NOx control efficiency declines as inlet NOx declines; AECI's proposed power plant, like other existing units, is capable of lower NOx emissions with a higher SCR efficiency."

MDNR Response: Per request of MDNR, AECI investigated the reasons why gas-fired power plants are capable of high removal efficiencies at low inlet NO_x rates as compared to AECI's proposed unit. AECI's response is summarized here,

> "With respect to essentially all of the design variables that affect SCR efficiency, including temperature, uniform flow, mixing, catalyst blinding, plugging, and deactivation; SCR control systems on coal-fired units present significantly more challenges than SCRs on natural gas-fired units. SCR control systems on natural gas-fired units have significantly less sulfur loading and particulate loading (including all of the trace particulate components that tend to blind and deactivate the catalyst) than a unit in coal-application. Natural gas-fired units can achieve more consistent flows and mixing, have smaller pitch and more catalyst surface area per volume of gas flow. Because of the significant differences in flue gas characteristics, there is no technical basis to establish coal-fired SCR performance based on performance achieved on natural gas-fired units."

MDNR accepts AECI's response as sufficient reasoning for the differences in SCR performance between coal-fired ant natural gas-fired units. AECI's full response can be seen in their supplemental response received by MDNR via email on January 16, 2008.

Comment X.B.2.iii: SCR performance is not limited by variability

Comment X.B.2.iii (Excerpt): "The Review Summary states that the 0.07 lb/MMBtu 30-day limit is acceptable because it "allows for short-term variability, especially at the end of catalyst life conditions."368 This variability is built in to the vendor guarantee, the averaging time of the permit limit (30- day and annual), and the exclusion of startup and shutdown events, which account for most of the variability in SCR operation. This statement is inappropriately used in the BACT analysis as an excuse for higher limits."

MDNR Response: The main reason for allowing a higher short-term limit as relative to the annual rate was to allow AECI some limited flexibility with regards to scheduling change-outs of one or more of the SCR catalyst beds. According to an article entitled <u>SCR maintenance fundamentals</u> (Wash U Ex. 60), "A catalyst's activity level will drop over time due to deposits of material the block actives sites, by physical erosion and damage, and by chemical attack on its active components….Timing is crucial [with regards to catalyst replacement]…Replacing an SCR system's catalyst is complicated and costly." Several issues regarding catalyst management must be taken into account. Some of the issues that are listed in the article include:

- Timing outages for catalyst replacement to coincide with other work so they don't interfere with electricity production,
- Increased catalyst loading may extend the time between outages for catalyst replacement; however, increased catalyst loading adds catalyst cost, increases the

conversion of SO_2 to SO_3, and increases parasitic loads due to pressure drop across the catalyst.

With a low annual NO_x limit of 0.05 lb/MMBtu, AECI will not be able to operate at the higher 30-day rate for a long period of time without sacrificing their ability to meet the annual rate. The higher 30-day limit coupled with a lower annual limit has been permitted for several other boilers. There are no other existing permitted boilers with annual rates lower than AECI. The 30-day rolling average for NO_x has been lowered to 0.065 lb/MMBtu. Please see responses to Comment X.B.5.i for further discussion on the lowering of 30-day rolling average NO_x rate.

Comment X.B.3. (excerpts). "Given that the SCR inlet rate and the removal efficiency are incorrect, the monthly and annual limits must be reduced… An inlet NOx rate of 0.15 lb/MMBtu on a 30-day rolling average (which is higher than has been routinely achieved at existing retrofit units) and a removal efficiency of 90 %, would reduce the 30-day rolling average emission limit to 0.015 lb/MMBtu. Given the same assumptions, the annual NO_x emission limit would be reduced to 0.012 lb/MMBtu."

MDNR Response: MDNR has evaluated the performance of the pulverized coal boilers achieving the lowest NOx rates in the country. There is no evidence that a pulverized coal-fired unit is capable of achieving a 30-day rolling average of 0.015 lb/MMBtu or an annual NO_x emission limit of 0.012 lb/MMBtu.

Comment X.B.4. Lower NO_x emission limits have been permitted.

MDNR Response: Wash U comments that other facilities have lower NO_x emission limits on a 30-day rolling average than the 0.07 lb/MMBtu proposed for AECI. They pointed out the TS Power Newmont facility was issued a permit in May 2005 for a 200 MW sub-critical PC boiler with a NO_x limit of 0.067 lb/MMBtu based on a 24-hour average, including startups and shutdowns. "In order to compare 24-hour and 30 day emission limits, an analysis was performed using emission data from several facilities. [They] analyzed 2005 ozone season NO_x data for 13 units to determine the relationship between different averaging times. [They] first calculated the maximum 24-hour rolling average. Then, using the same data set, [they] calculated the maximum 30-day rolling average." They then took the average ratio of 30-day to 24 –hour emission rate for their data set and applied it to the 0.067 lb/MMBtu 24-hour limit to derive an "equivalent" 30-day limit of 0.018 lb/MMBtu for AECI. As stated in Response to Comment X.B.2.i, MDNR believes this method is not a valid approach for a setting BACT NO_x limit that is supposed to be conducted on a case-by-case basis.

As far as MDNR can interpret from comments and attachments, Wash U did not follow any standardized method other than to note that "the ratio approach to averaging times has been commonly used to convert the output from the EPA SCREEN model, which outputs hourly average concentrations, to different averaging times". IN any event, MDNR believes Wash U has made an error in their calculations by inadvertently switching the maximum 24-hour numbers with the 30-day numbers. For example, the Trimble facility in Kentucky, as shown in Wash U's Ex. 75, has a maximum 24-hour number of 0.038 lb/MMBtu. However, using the same data set, the Trimble facility was calculated to have a maximum 30-day average of 0.165 lb/MMBtu. It is impossible to have a higher 30-day average than a maximum 24-hour rolling average if the same data set is used. MDNR, using EPA's Clean Air Market Database, did a quick analysis of the facilities in Wash U Ex. 75 and was able to ascertain that the maximum 24-hour number in Ex. 75 were in fact the maximum 30-day number. This makes the average ratio 3.33. If MDNR were to apply the ratio method as suggested by Wash U, the 30-day "equivalent" would be 0.067 lb/MMBtu multiplied by 3.33 which equal 0.22 lb/MMBtu. This number is higher than what AECI expects to typically achieve with combustion controls alone. Because of the errors in calculation in addition to the belief that the use of this ratio method is flawed, this basis will not be used by MDNR to lower the 30-day NO_x limit.

Wash U have listed several facilities with proposed or permitted limits lower than the 0.07 lb/MMBtu 30-day NO_x limit proposed by AECI. These include the following:

- Desert Rock facility in New Mexico with a 0.06 lb/MMBtu limit, based on a 24-hour average (permit issued July 2006)
- Roundup Power Bull Mountain with a 0.07 lb/MMBtu , based on a 24-hour average (permit issued December 2005)
- Springfield City Water, Power and Light in Illinois with a 0.05 lb/MMBtu exclusive of startups and shutdowns (SU/SD) and a 0.06 lb/MMBtu inclusive of SU/SD, both based on a 30-day rolling average (permit issued August 2006)
- Toquop facility in Nevada with a 0.06 lb/MMBtu on an hourly basis (application submitted in July 2007)
- Florida Power and Light – Glades facility with a 0.05 lb/MMBtu on a 24-hour rolling average (application submitted in March 2007)

The last two facilities have proposed limits and have not undergone BACT analysis. None of the above facilities have demonstrated compliance with their respective limits. In addition, MDNR is not aware of any other operating facilities in the country that have demonstrated continual compliance with the limits given above. W.A. Parish show daily averages greater than 0.06 lb/MMBtu approximately 30 to 80 times since the addition of the SCRs to the boilers (this excludes the initial shakedown period). For this reason, MDNR will not propose additional 24-hour or hourly average limits. However, upon further review of actual data from other facilities, MDNR has decided to lower the 30-day NO_x average from 0.07 lb/MMBtu as proposed in the draft permit to 0.065 lb/MMBtu. Please see response to Comment X.B.5.i for further discussion.

Comment X.B.5. Lower NO_x emissions have been achieved.

Comment X.B.5.i: Emission data from KCP&L Hawthorn Unit 5 and the W.A. Parish Generating Station were incorrectly interpreted to support a less stringent NO_x emission limit.

MDNR Response: At the time the permit was drafted, KCP&L Hawthorn Unit 5 was the only new (not retrofitted) PRB coal-fired pulverized coal (PC) unit with SCR control. Therefore, it was included in our analysis to show what was achievable. According to data collected from the Clean Air Market database (July 2004 to March 2005) and statistically analyzed by AECI, the unit had achieved 0.079 lb/mmBtu on a 30-day rolling average with a 95% confidence. This data was taken from a time period after the rebuilding of Unit 5. Therefore, it set a maximum NO_x emission rate for a 30-day rolling average. Further analysis showed that the units at W.A. Parish were achieving much lower NOx rates. Since W.A Parish represented the lowest NO_x emission rates being achieved in the country, the W.A Parish performance data was ultimately relied upon more heavily to aid in setting the NOx BACT limits.

AECI also chose to evaluate NO_x emission rates achieved at W.A. Parish Generating Station Units 5 and 6 as representative to what AECI could achieve in practice. Wash U advocated that "AECI should include all of the Parish data in order to present a representative analysis of the Parish plant. [AECI] must include the data from all boilers at Parish, and especially must include the entire period of record for all boilers." There are two other boilers with SCRs located at the W.A Parish Generating Station, Units 7 and 8. MDNR evaluated data from these units prior to issuance of the draft permit, but inadvertently left this data out of the BACT write-up. This data as well as the data from the time MDNR completed its evaluation to the 2nd quarter of 2007 has been further examined. The BACT analysis has been updated to reflect this information.

MDNR still maintains that the 12-month rolling average BACT limit of 0.05 lb/MMBtu is valid. Review of the Clean Air Market database for W.A Parish Units 5 through 8 show 12-month rolling averages in excess of 0.05 lb/MMBtu for three of the four units from time post-startup of the SCR to September of 2007.

Table 1: W.A Parish 12-month rolling averages
(Post-startup of SCR to Sept. 2007)

Unit	Maximum 12-month rolling	Minimum 12-month rolling

	average (lb/MMBtu)	average (lb/MMBtu)
5	0.055	0.031
6	0.052	0.032
7	0.051	0.035
8	0.045	0.038

It should be noted that W.A. Parish has a system cap that allows them to balance the total NO_x emissions amongst four units to achieve a desired overall emission level. In other words, if one or more units are not performing at target levels, W.A. Parish has the capability of balancing these higher emissions by temporarily over-controlling other unit(s). AECI will not have such flexibility and will have to meet emission limitations even if the facility is experiencing problems. It should also be noted that Unit 8 of W.A Parish is co-fired on natural gas, with natural gas as the primary fuel. It also worth noting that Unit 8 has the capability of burning natural gas, with natural gas as the primary fuel. This firing configuration is confirmed by the RBLC database. Therefore, Unit 8's emission rates are not as representative as Units 5 through 7 which burn only coal.

Comment X.B.5.i.(excerpt) "Unit 5 does experience an upward trend in its NO_x emissions (note that it drops back down in March 2007); however, the highest 30-day rolling average experienced by the unit from January 2003 to March 2007 is 0.059 lb/MMBtu as a maximum 30-day rolling average, including startups and shutdowns. This is still lower than the limit being proposed for AECI. Unit 6 shows slight increases in NO_x emissions as well, but its 30- day rolling average never exceeds 0.049 lb/MMBtu."

"Unit 7 stays at approximately 0.05 lb/MMBtu for the duration of the data set. There is a dramatic increase in daily NO_x emissions in March-April of 2006, but after a shutdown, the unit's daily emissions return to below the 0.05 lb/MMBtu mark and the rolling 30-day average never exceeds 0.054 lb/MMBtu. Unit 8 consistently performs well. The highest 30-day rolling average is 0.048 lb/MMBtu."

MDNR Response: In the Wash U's Exhibits 83A-83D, the first day used in calculating the 30-day rolling average calculations were June 18, 2003 and December 1, 2003 for Units 5 and 6, respectively, not in January of 2003 or April of 2003 as stated in their comments (page 95 and 97). Units 5 and 6 were started up in April and January of 2003. In addition, the data given in Exhibits 83A-83D have gaps where a 30-day rolling average is not calculated or is calculated using days when CEMs data is unavailable. AECI will not be able to include the days that the system is not operating into their rolling 30-day average emission rate. Having days with zero emissions averaged into it leads to lower NO_x rates.

Because of these errors, MDNR evaluated W.A. Parish data provided by AECI for the rolling 30-day averages of all 4 units from 2003 through 3rd quarter of 2007. AECI processed the data by removing days where the boiler was not operated and recalculating the 30-day averages. Upon request by MDNR, they also conducted an analysis which excluded periods when the units were offline as well as the initial shakedown periods when the SCRs first came on-line. MDNR analyzed and verified the data provided by AECI.

It is worthy to note that during the time between startup and the first date used by Wash U, all units had 30-day rolling averages that exceeded 0.08 lb/mmBtu. Please see Attachment A to the Response to Comments[4]. However, during periods where SU/SD is excluded, the highest 30 day average rates for Units 5 through 8 are approximately 0.061, 0.060, 0.057, and 0.091 lb/MMBtu, respectively. Because these units with the exception of Unit 8 have consistently achieved rates well below the proposed 0.07 lb/MMBtu level, MDNR has lowered the 30-day rolling NO_x average from 0.07 lb/MMBtu to 0.065 lb/MMBtu.

4 Attachment to email sent 1/14/2008 from Todd Tolbert of AECI, "Response on 30-day average.doc"

Comment X.B.5.ii: *Emission data for ozone season facilities should be considered in the determination of a* NO_x *emission limit.*

MDNR Response: MDNR believes that performance data from ozone-only operated boilers are a valuable source of information mainly because it shows what NO_x rates can be achieved. However, ozone-operated units have many advantages over those units that are operated year-round. According to one article, "Emission rates achieved during ozone season-only operation may be lower than rates that can be achieved year-round, because of less time available for undertaking maintenance and for implementing performance-improving measures."[5] Since there is uncertainty in how much of an advantage ozone-only operated units have over year-round operation and since there are several units that operate year-round that have some if not the lowest demonstrated NO_x emissions that are directly comparably to the boiler proposed by AECI, MDNR decided to give more weight to the performance of those units operated year-round.

Wash U cited several articles to "demonstrate the relevance of ozone-season only data to year-round operation". In one study, the authors examined twelve (12) year-round operating SCR systems where they compared variability of year round operation to the variability of the same units during the ozone season. In other words, they were analyzing the ability of the units to maintain a consistent outlet emission rate. This was not a comparison of performance between ozone-season only operated units to year-round operated units as portrayed by Wash U. It was an examination of ability to achieve consistent performance. The coefficient of variation (CV) used throughout the article was used as an indicator of the reliability of the system to maintain a steady emission rate, not as an indicator in achieving a specific emission rate. Therefore, based on this article, one cannot make the conclusion that Wash U made that "facilities that operate only during the ozone-season can be [directly] compared to facilities operating year-round." Nor can you make this conclusion for units that were originally designed for ozone season operation and subsequently converted to year-round facilities unless you are directly comparing performance data, which the source does not. Just because you can convert an ozone-only operated SCR to year-round operation does not mean that their performance will be equal.

Another argument used by Wash U directly comparing ozone-season to facilities operated year-round is that many of the ozone-season units must operate year-round starting in 2009 to comply with BART. However, again without direct data, the capability of ozone-season unit to operate year-round does not implicitly mean that these units will have the same performance level during ozone only conditions versus longer term operation.

For the reasons listed above, MDNR does not believe that Wash U has offered any convincing arguments telling why ozone-only operated units will not have advantages over year-round units. Therefore, MDNR will not use ozone-only operated unit performance data for setting a limit that will require continuous compliance.

Comment X.B.5.ii (paraphrased): The ozone season NO_x CEMs data summarized in Table 4 represent a worst-case for AECI for the following three reasons: 1) some periods of startup, shutdown and malfunction are included in the rolling average reported in Table 4, 2) the NO_x controls on the units in Table 4 were installed as retrofits and in the case of retrofit plants, SCRs are not optimally designed, and 3) most of the units currently achieving low NO_x emission rates are subcritical boilers.

MDNR Response: MDNR does not believe that Wash U has submitted sufficient reasoning to justify why ozone-season NOx CEMs in Table 4 represents a worst-case scenario. With regards to their first reason, Wash U states that they took EPA's daily average data from each ozone season and "eliminated days with invalid heat input data and days with less than 24 hours of NO_x data that were preceded or followed by a least one day with zero operating hours (major startups and shutdowns). Startups and shutdowns (SU/SDs) that lasted less than 24 hours were included in the average, thus overestimating the 30-day rolling average…" However, Wash U did not provide the analysis of the ozone season units showing that SU/SD lasting less then 24 hours resulted in the highest 30-day numbers. In the analysis of W. A. Parish, some of the highest

[5] J. Edward Cichanoicz, Michael Hein, James Marchetti, Comparison of EGU1 and EGU2 to Consent Decrees and BACT Limits, August 1, 2005

numbers were not a result of SU/SD and in some cases the SU/SD events lowered 30-day rolling average. Regardless, W.A Parish has accomplished the same 30-day average NO_x levels over an ozone season that the best units in Table 4 have accomplished. MDNR's main question here is not whether performance of 0.04 lb/MMBtu or better is achievable, but whether this performance is sustainable over longer periods of time. Therefore, MDNR still maintains that the W.A. Parish is the most representative unit and has depended on its performance in helping to set a 30-day and annual limit for AECI.

With regards to the second reason, Wash U argues that "in cases of retrofit plants, SCRs are not optimally designed" and that "AECI, as a new plant, should have less difficulty meeting a lower SCR inlet rate then those plants with retrofit SCRs". Upon further review of the sources used to make these conclusions, the cited article summarized some of the challenges in designing retrofit SCRs; however, it went on to say that all of the SCRs designed by the manufacturer were achieving their design SCR removal efficiencies. The conclusion reached by MDNR from this article is that although retrofits have some unique design challenges, these challenges can be overcome. Therefore, a case can be made that a new unit should operate at least as good as a retrofit, but a case cannot be made that a retrofit cannot operate optimally or that a retrofit will have lower performance simply because it is a retrofit.

Lastly, Wash U makes the argument that "most of the units currently achieving low NO_x emission rates are subcritical boilers" and that "less coal is burned and less NO_x, SO_2, PM, PM_{10}, etc are emitted from a supercritical boiler than a subcritical boiler per megawatt hour of electricity generated". They then go on to make the conclusion that "boiler outlet NO_x emissions would be lower than those at subcritical plants". Though this is true when comparing pounds per megawatt-hour of subcritical and supercritical units, it does not hold true when comparing pounds per MMBtu of coal burned.

Comment X.B.6: All arguments made to justify a lower 30-day rolling average NO_x emission limit can also be made in support of a lower annual NO_x emission limit.

MDNR Response: MDNR based its decision for an annual limit of 0.05 lb/MMBtu exclusive of startup and shutdown on actual performance data from other plants and NOx BACT limits from other proposed and permitted units. There are no other units with a proposed or permitted annual limit lower than that proposed for the new AECI boiler.

Comment C.: The Stated BACT Limits for SO_2 Emissions from the Main Boiler Do Not Reflect BACT.
Comment X.C.1.i (excerpt, summary): The BACT Analysis fails to identify all control technologies, specifically Electro-Catalytic Oxidation (ECO).

MDNR Response: In identifying possible SO_2 control technologies, MDNR reviewed the SO_2 BACT analysis as submitted by AECI in their application as well as other documents and data including review of other technical publications, SO_2 limits and BACT analysis of recently issued permits and proposed units.

The ECO system as identified by the Wash U was not specifically identified by MDNR as a possible SO_2 control technology. At the time of the AECI submittal (January 2006), Powerspan in partnership with FirstEnergy Corp. had only recently completed testing of their 50 MW commercial demonstration unit (September of 2005). Since then, two plants, FirstEnergy's Bay Shore Unit 4 – 215 MW and AMP-Ohio's new Mieg County Plant – two 500 MW, made commitments to construct the ECO system in May and June of 2007, respectively[6]. These are the first known commercial units that have committed to installing the ECO system. It should be noted that neither of these plants are currently operational and demonstration of the ECO system has not been conducted on a full-scale system. It should also be noted that the Bay Shore Unit is a FirstEnergy facility who has an extended partnership with Powerspan to develop this technology and therefore has an invested interest in seeing its success.

[6] Powerspan Company Fact Sheet, www.powerspan.com/news/factsheet.shtml

According to the permit for the AMP Ohio units, wet flue gas desulfurization (WFGD) was considered as BACT control for SO_2 and not the ECO system specifically. As a side note, the ECO system being proposed for the AMP Ohio unit is being designed as an SO_2 control system, not as a multi-pollutant control system. According to further conversations with the OhioEPA, the coal content of the sulfur is approximately 3.5% and an approximate SO_2 removal efficiency of 97% is required.

Although the ECO system has completed demonstration tests on small systems, MDNR believes that the technology has not been commercially demonstrated for the following reasons: 1) the ECO system has been demonstrated on a unit that is 1/15th the size of the unit proposed by AECI, and 2) the ECO system has not been demonstrated or proposed, to MDNR's best knowledge, on units firing low-sulfur coal. For these reasons, further testing and design would be required to account for scaling the plant by 15 times and to demonstrate the effectiveness of the system on low-sulfur coal. As a result, MDNR does not currently consider the ECO technology to be "commercially demonstrated" and will not review the ECO system any farther.

Comment X.C.1.i (excerpt, summary): Combinations of dry and wet FGD should have been considered in the BACT analysis for SO_2.

Wash U specifically mentions the E-LIDs process (Enhanced Limestone Injection Dry Scrubbing) proposed by Babcock & Wilcox and an integrated dry and wet scrubber offered by Alston as two technologies MDNR failed to consider. The E-LIDs was proposed in a Babcock & Wilcox (B&W) paper which has been cited in several instances in Wash U's Comments. The proposed units as described in the paper have not been built and are based on a theoretical design that is clearly a hypothetical exercise that should not serve as a basis for imposing an emission limitation that must be consistently achieved. It is not clear from the supporting documents given by Wash U whether the E-LIDs process has been installed on a full-scale system. A further search for more information on a full-scale system operation has not disclosed any additional insight. Because of the lack of information on the E-LIDs system, MDNR assumes that this specific technology is still undergoing development and has not been commercially demonstrated. With regard to the integrated dry and wet scrubbed, a search of Alstom's website did not mention this particular system. Again, because of the lack of information, MDNR assumes that the technology is still undergoing development and has not been commercially demonstrated.

Comment X.C.1.i (excerpt, summary): Combinations such as sorbent injection and dry or wet FGD should have been considered in the BACT analysis for SO_2.

MDNR agrees with Wash U that "sorbent injection into the boiler or ductwork is an available and applicable control technology for SO_2 control on pulverized coal plants". MDNR included dry sorbent injection as an SO_2 control technology in its BACT analysis of the draft permit. MDNR stated that control efficiencies up to 50% can be achieved. However, Wash U has provided multiple sources showing higher removal efficiencies are possible.

- In Wash U's Exhibit 158, a control efficiency of up to 60% was stated as being achievable; this efficiency was at higher than typical reactant feed rates.
- A STAPPA/ALAPCO report, Wash U's Ex 169, states the "SO_2 control-efficiency of existing dry injection system ranges from 40 to 60 percent when using lime or limestone, and up to 90 percent using other sorbents (e.g., sodium bicarbonate)".
- Wash U's Ex. 159 showed a control efficiency of 75% for dry sorbent injection using sodium bicarbonate.
- According to a U.S. EPA Report published in March 2005, Multipollutant Emission Control Technology Options for Coal-Fired Power Plants (Wash U, Ex. 219), control efficiencies range from 40 to 85% depending on sorbent type and stoichiometry, amount of recycle, temperature and plant configuration. However, this report also states that status of the SO_2 Sorbent technology is at a pilot scale to pre-commercial demonstration level.
- In another EPA document (Wash U Ex. 93), limestone injection is credited with 25 – 35% removal, but also states that it depends on coal sulfur content with the caveat that removal

efficiency is lower with western coal. It goes on to say that "in-situ control is used effectively in CFB boilers, and may be used in a PC boiler by using limestone injection into the furnace; however the level of control that is achievable is not comparable to post-combustion SO_2 control systems".

In each of these cases, the dry sorbent injection was the sole SO_2 control method and not used in combination with other SO_2 control technologies such as dry or wet FGD. Using sorbent injection upstream of a dry scrubber does not provide additional control. The calcium oxide that naturally occurs in the PRB coal in conjunction with the lime injected into the dry FGD vessel already provides a maximum SO_2 removal with calcium to sulfur stoichiometric ratio greater than 1:1. Sorbent injection may reduce the amount of hydrated lime needed in the dry scrubber, but it will not increase the amount SO_2 removal. According to Wash U's Ex. 219, "the duct injection of lime slurry is a process similar to a conventional spray dryer. The main difference is the elimination of the large reaction vessel." The dry scrubber reaction vessel, however, provides a larger residence time to allow for completion of reactions and thus higher SO_2 removal; therefore, assuming that the dry scrubber reaction vessel is sized appropriately, dry sorbent injection would be considered redundant.

According to the NSR Workshop Manual (page B.17), "combinations of techniques should be considered to the extent they result in more effective means of achieving stringent emissions levels represented by the "top" alternative". MDNR believes that sorbent injection in addition to a dry or wet FGD system does not provide for greater SO_2 control and therefore maintains that it was acceptable for MDNR not to review the combination of FGD with sorbent injection. MDNR also believes that the elimination of sorbent injection on its own from further technical consideration was also appropriate. However, MDNR believes that the removal efficiency by sorbent injection may be higher than the 50% quoted in the draft permit and therefore will update the permit to reflect a higher SO_2 removal efficiency by injection of dry sorbent.

[As a side note, it is important to note that in the case of sodium-based sorbents which typically achieve the higher sorbent removal efficiencies, there are several concerns with its use. The disposal of solid waste (from the fabric filter where the solids are capture) needs to take into account the solubility of sodium compounds in water and associated concerns with the handling of sodium-containing leachate from the landfills as well as a need for increased water consumption mainly due to ash conditioning (Wash U Ex. 219).]

Comment X.C.1.ii: The BACT analysis prematurely rejects control technologies during the top-down process.

MDNR Response: The jet bubbling reactor (JBR) was identified as a possible SO_2 control technology during the BACT review. However, further evaluation of the JBR's technical feasibility showed that JBR technology at the time of initial review had never been installed on a large coal-fired boilers firing subbituminous coal in the United States. Further detailed information on units located outside of the United States was limited. Since completion of this portion of the review, the JBR has continued its commercial development as evidenced by the vendor list provided in Exhibit 94.

The sulfur content of the coal plays a significant role in the degree of reduction that can be expected from a SO_2 control technology. In the CT-121 wet FGD experience list, of the 21 existing and proposed units which have an inlet SO_2 level of less than 1,000 ppm (AECI's inlet is approximately 640 ppmvd), only two systems have a reported SO_2 removal of 99% whereas the remaining 19 units have SO_2 removal efficiencies of 95% or less. The experience list does not state how the performance levels were determined, i.e continuous monitoring or just a one-time test. Since all of these units are located outside of the United States, the data showing the ability of these units to achieve their SO_2 removal on a continuous basis is not readily available. It is also interesting to note that all CT-121 wet FGD units that have been installed or are being proposed in the United States have inlet SO_2 concentrations greater than 1,200 ppm with design removal efficiencies no higher than 98 %.

Wash U contends that jet bubbling reactors have been used to achieve high SO_2 removal efficiencies on other similar gas streams containing comparable amounts of SO_2 to that of AECI. The CT-121 performance cited in Wash U Ex. 95 shows a 99% control effectiveness for SO_2 ranging from 450 to 300 ppm over a 72-hour period (Figure 2). MDNR asserts that the time frame for this testing is not enough to demonstrate long-term performance of the system on low inlet SO_2 streams. There are many process-related things that you can do to the FGD on a short-term basis to increase removal efficiency, such as increasing pH of the scrubbing liquor or increasing pressure drop across the system. Figure 3 of the same article shows that an increase of 26% in additional power consumption (due to pressure drop increase) increases the removal of SO_2 increasing from 95% to 99%. This begs the question of whether a facility can afford to run the system at a higher pressure drop and for how long. Wash U also cites the 1-year performance of Kobe in Japan with similar design inlet SO_2 levels to AECI (Wash U Ex. 94). However, in Ex. 95, the 8 units that were immediately started-up after Kobe which similar inlet SO_2 levels had design SO_2 removal efficiencies of 95% or less.

Wash U included Exhibits 96 through 99 as evidence that the removal efficiency of a JBR increases as the SO_2 content at the inlet decreases and thus showing that "wet FGD inlet SO_2 concentration has no effect upon or is inversely related to SO_2 removal efficiency". There are several things to note. Figure 9 of Ex. 96 which shows this trend for the jet bubbling reactor also shows that for all the coal sulfur contents tested the removal efficiency maxed out at 97%, not at 99% as indicated earlier. In most of the conclusions from these studies, the reason for the decrease removal at higher inlet SO_2 concentrations were due to increasing the gas volume to obtain the high SO_2 which resulted in a decrease in contact time with the scrubber liquor.

Contrary to the above line of reasoning, in several other papers cited by Wash U, the authors assert that as SO_2 concentrations decrease, SO_2 percent removal decreases. One such case is Wash U Ex. 100. In Fig 2.1-1, for dry scrubbers, at levels below the inlet SO_2 levels of 1.5 lb/MMBtu, removal efficiency decreases as inlet SO_2 levels decrease. Moreover, as seen on the CT-121 and Marsulex wet FGD Experience Lists (Wash U's Ex. 9 and, 109), the higher SO_2 removals are in almost all cases associated with units that have high inlet SO_2 concentrations. This is also reflected in limits given in recently proposed and permitted permits. These points seem to be in direct conflict with the commenter's arguments above. Because of this conflict, MDNR has chosen to gives more weight to actual proven performance and what other facilities have implemented.

Regardless, the jet bubbling reactor technology is a variation of the wet FGD technology. Although the method of contact between the SO_2 and the limestone slurry is different from other wet FGD systems, the reaction chemistry is the same and most of the reasons for eliminating the wet FGD will apply to the jet bubbling reactor. As seen in the BACT analysis by AECI and MDNR and these Responses to Comments, wet FGD systems were thoroughly reviewed and have been eliminated due to environmental, energy and economic reasons. Please see the appropriate sections for further discussion.

Comment X.C.1.iii. (summarized): The spray dryer absorber (SDA) and wet FGD control efficiencies referenced in the BACT Analysis of the Draft permit are too low.

Comments X.C.1.iii (excerpt): Sargent & Lundy, a large architect and engineering firm that provides scrubber design services for coal fired boilers (and AECI's engineer), reviewed the available scrubber technology in March 2007 for the National Lime Association. This study [Wash U. Ex. 100] concluded that for wet FGD system, "SO_2 removal guarantees of up to 99% (without additives) are available from the system suppliers and have been demonstrated in commercial applications." For spray dryer absorbers, Sargent & Lundy concluded that "experience with Powder River Basin (PRB) coal has prompted equipment suppliers to guarantee SO_2 reduction efficiencies of up to 95% or as low as 0.06 lb/MMBtu." For circulating dry scrubbers, Sargent & Lundy concluded that "SO_2 removal guarantees of 95-98% are available from the system suppliers identified below. The CDS technology has been demonstrated to achieve these levels of SO_2 reduction efficiency." Sargent & Lundy prepared a typical design for each of these types of scrubbers for three types of coal and a cost estimates for each. The SO_2 control efficiencies selected for this design are 95% for the spray dryer absorber and 97.2% for both the circulating dry scrubber and wet scrubber.

MDNR Response: MDNR agrees that the control efficiencies referenced in the draft permit are too low. The draft permit states a control efficiency of 92.5%. Before issuance of the draft permit, several changes to the SO_2 BACT were made. These changes were inadvertently left out of the draft permit. The updated percent reduction estimated for the dry FGD system is 93.4%. This was based on an emission rate of 0.08 lb/MMBtu at maximum sulfur content of 0.5% and a heating value of 8,100 BTU per pound. An updated removal efficiency of 95.1% was used for the wet FGD performance. This was based on an emission outlet of 0.06 lb/MMBtu also at maximum sulfur content of 0.5% and a heating value of 8,100 BTU per pound.

MDNR does not argue with Wash U's assertions that these higher control efficiencies are achievable, but does question whether these efficiencies are achieved on a continuous basis and with low sulfur coal. Figure 2.1-1 of Wash U Ex. 100 shows the relation between inlet SO_2 and SO_2 removal efficiency for lime spray dryers. According to this study, the maximum removal efficiency is approximately 95% for lime spray dryers. The removal efficiency of SO_2 declines at levels below a concentration of 1.5 lb/MMBtu and remains steady at 95% for SO_2 loadings from 1.5 lb/MMBtu to 3 lb/MMBtu. A similar graph is not provided for wet FGD. Nevertheless, the authors do state that SO_2 removal guarantees of up to 99% have been provided. They were not specific to what inlet SO_2 levels this higher efficiency applies. However, they do state that there is a "practical outlet limitation at 0.04 lb SO_2/MMBtu" for wet FGDs. It is important to note that there are no wet or dry FGDs that have BACT limits lower than 0.06 lb/MMBtu (see Response to Comment X.C.1.iv.).

In the final decision on Longleaf, the document states the following:

> Longleaf's use of a 90 to 92.7% SO_2 control efficiency range for dry scrubbers is consistent with available information, EPA Comments, and expert opinion. In comments regarding the Newmont Nevada Energy Investments, LLC's coal-fired power plant PSD permit application, EPA concluded that a dry scrubber SO_2 control efficiency of 92.3% "is at the top end of the range of what can be achieved with dry scrubbing." In comments on the emission limits for the coal-fired Commanche power plant in Colorado, EPA agreed with the applicant that a SO_2 control efficiency of 91.1% was BACT for the PRB coal-fired facility… Dr. Fox claimed that 95% SO_2 control efficiency is achievable for dry scrubbers, yet nevertheless conceded that Longleaf would be "hard pressed to achieve 95%." On the final day of the hearing, Dr. Fox acknowledged that the most recent permits for facilities with dry scrubbers use SO_2 control efficiencies between 90 and 93%.[7]

In another article (Ex. 226) referenced later by Wash U, the engineering consultant who wrote the analysis assigned a design removal efficiency of 95% for the wet FGD and 90% for the dry FGD. The authors go on to the say that

> "the removal efficiencies provided in this table are meant to represent the average long-term performance of the FGD system when firing the range of low-sulfur design coals. Actual performance capability of the wet and dry FGD systems would be 2-3 percent higher when burning the expected range of sulfur content in PRB coals. FGD systems can typically meet these higher control efficiencies when the system is new and the vendor personnel are on-site to oversee the performance test. Based on a survey of existing FGD system historical performance, minor operating problems and equipment/instrumentation failures will typically result in a reduction of 2-3 percent below the guaranteed performance efficiency over long-term operation."

The US EPA's Environment Appeals Board (EAB) contends that "permitting agencies have the discretion to set BACT limits that do not necessarily reflect the highest possible

[7] [7]Friends of the Chattahoochee, Inc. and Sierra Club, Petitioners, v. Dr. Carol A. Couch, Director, Environmental Protection Division, Georgia Department of Natural Resources, Respondent, and Longleaf Energy Associates, LLC. Intervenor. Docket No.: OSAH-BNR-AQ-0732139-60-Howells. December 18, 2007

control efficiencies but, rather, will allow permittees to achieve compliance on a consistent basis". The study above acknowledges that there is a difference between actual performance capability and long-term performance. At any rate, the percent removals proposed by MDNR for a worst case sulfur content of 0.5% fall between the levels given in each of the studies.

According to further conversation with Sargent & Lundy, the control efficiencies quoted in the article referenced above are design targets. They state that the actual performance of the scrubber will fluctuate around the design target due to typical system operating parameters. Some of these operating parameters that cause variability in FGD performance are inlet temperatures, SO_2 loading, ash loading, degree of mixing, reagent purity and boiler loading. AECI submitted data for three scrubbers showing this typical fluctuation.[8] Based on 30-day average emission rates with 95% confidence level, all of the 30-day average rates were within 25% of the long-term average. Therefore, AECI concluded that a margin of at least 20% would be needed between the design target and the permit limit to account for typical system fluctuations. Based upon a design target of 0.06 lb/MMBtu, a 20% margin is equal to a maximum outlet SO_2 rate of 0.074 lb/MMBtu. Since AECI expects to operate at sulfur contents between 0.2 wt% and 0.4 wt%, MDNR has lowered the middle SO_2 ties from 0.075 lb/MMBtu to 0.074 lb/MMBTU.

Comments X.C.1.iii.a (summary): The spray dryer absorber control efficiency referenced in the BACT Analysis of the Draft permit is too low. In the comments regarding the dry FGD, Wash U calculated the control efficiency of the tiers assuming a coal heat content of 8,100 Btu/lb and a 10% loss in coal sulfur between the pulverizer and inlet to the scrubber.

MDNR Response: MDNR agrees that there is some coal sulfur loss whether in the fly ash or due to crushing activities; however, the amount of sulfur loss is in question. Regardless, it is common practice to assume that all sulfur in the coal is oxidized. This allows for direct comparison of limits and removal efficiencies amongst facilities. In addition, MDNR has based the potential to emit (PTE) on a worst case basis. if the 10% coal sulfur loss were to be taken into account, the PTE of the project would be less.

Therefore, MDNR calculates the following removal efficiencies for each of the ties:

- Coal sulfur contents between 0.4 and 0.5% -- removal efficiency ranges from 91.9% to 93.5%
- Coal sulfur contents between 0.21 and 0.39% -- the removal efficiency ranges from 85.7% to 92.3%
- Coal sulfur contents below 0.2% -- the removal efficiency starts at 85.8% and decreases as sulfur content decreases.

A decrease in removal efficiency as the sulfur content decreases has been asserted by many permitting agencies and technical documents. Exhibit 100 as stated earlier also supports this relationship between inlet SO_2 and the maximum SO_2 removal. As such, MDNR feels the tier approach is appropriate. The sulfur content in the coal proposed by AECI will be no higher than 1.23 lb/MMBtu with typical amounts expected to be between 0.52 and 0.96 lb SO_2/MMBtu.

Comments X.C.1.iii.b (summary): The circulating dry scrubber (CDS) control efficiency referenced in the BACT Analysis of the Draft permit is too low.

MDNR stated that the CDS is capable of 93.4% SO_2 removal. This was based on an emission rate of 0.08 lb/MMBtu at maximum sulfur content of 0.5% and a heating value of 8,100 BTU per pound.

[8] Email received from Brent Ross of AECI to Kendall Hale of MDNR regarding DFGD Variance, dated February 22, 2008

Wash U gave several examples of facilities with alleged removal efficiencies greater than those stated by MDNR. The CDS at Black Hills Power & Light's Neil Simpson Unit 2 was guaranteed to achieve a minimum of 98% removal on low sulfur western coal. However, data on the EPA's Clean Air Market website show that lowest SO_2 lb/MMBtu rate achieved on an annual basis from 1995 to 2006 was 0.12 lb/MMBtu. Also according to Wash U. Ex. 104, the Neil Simpson Unit 2 experienced severe corrosion during operation of the CDS. With regards to the AES Guayama Puerto Rico facility, Wash U reported that a 95% control was guaranteed while burning low sulfur coal. It appears that this system comprised of a circulating fluidized bed boiler with limestone injection **and** an add-on CDS scrubber. The portion of SO_2 removed by the limestone injection versus CDS alone is not stated.

Comments X.C.1.iii.c (summary): With regards to the wet FGD technology, Wash U states that wet scrubbers can achieve 98% control or greater on low sulfur coals based on information gathered from brochures, technical documents and other plant's permitted limits.

MDNR Response: The BART regulations is one source that is cited to demonstrate that MDNR should use a higher removal efficiency. Wash U correctly states that a minimum SO_2 removal efficiency of 95% is required for applicable retrofits. However, the entire rule reads that "you must require 750 MW power plants to meet specific control levels for SO_2 of either 95 percent control or 0.15 lbs/MMBtu, for each EGU [electric generating unit] greater than 200 MW that is currently uncontrolled…[emphasis added][9]. The highest limit proposed for the proposed AECI boiler is 0.08 lb SO_2 /MMBtu which is well below the 0.15 lb/MMBTU level stated in the BART regulations.

In addition, there are also multiple alternative wet FGD technologies cited by Wash U in an effort to demonstrate that the removal efficiencies used by MDNR are too low. One includes the Glades plant that had a reported guarantee of 99% SO_2 removal using the Alstom's conventional scrubbers. This was a proposed limit and technology by the facility. This plant, however, is not being built due to denial by Florida's Public Service Commission denial of application for a new power plant. A PSD permit nor a BACT analysis was ever completed for this plant.

With regards to the Marsulex advanced scrubber to be built at Fayette Units 1 & 2, the removal efficiency is expected to be 97%, not 98%, as stated in the comments. It is important to note that there are no permitting limits associated with these systems that have to be met on a continuous basis.

With regards to Wash U's overall assertions, MDNR agrees that higher controls appear to be possible with wet FGD as compared to dry FGD systems. However, the validity of a vendor's claims is difficult to ascertain from brochures and literature. It is also hard to compare one-time emissions test that are given in these documents with specified permit limits, which must be met at all operating time periods including long-term. With regards to the Flowpac, Advatech, and Marsulex FGD systems, the cited documents do not provide clear indication of compliance tests or relevant time periods that such compliance tests would apply. In most cases, the inlet SO_2 appears to be much higher than that which will be found at AECI. In summary, the references appear to be promotional literature rather than a thorough engineering analysis. Therefore, the data in these exhibits are not relevant to setting a BACT emission rate that has to be consistently achievable.

MDNR has reviewed a large amount of articles, studies and permits. Overall, MDNR does not believe that Wash U has supplied sufficient evidence to demonstrate that the highest control efficiencies (98% plus) achieved by wet FGD are consistently achievable on systems using low sulfur coal.

Comments X.C.1.iii.c (summary): Wash U notes several plants that are currently operating with low sulfur coal and achieving high removal efficiencies

[9] Federal Register/Vol. 70, No. 128/Wednesday, July 6, 2005/Rules and Regulations

MDNR Response: Prior to updating the SO_2 BACT, MDNR asked AECI to resubmit the SO_2 BACT economic analysis for wet FGDs based on outlet emission rate of 0.06 lb/MMBtu basis on a 30-day basis. This emission rate level although using a different averaging period as used by Toquop and Desert Rock is amongst the most stringent SO_2 BACT limits that have been permitted. See the Response to Comment X.C.1.iv for further discussion of wet FGDs.

Comment X.C.1.iv: The BACT analysis fails to properly consider economic, energy, and environmental impacts.

MDNR Response: After identifying all control options and eliminating those that were not technically feasible, wet FGD was identified as the top control. However, wet FGD was eliminated, based on energy, environmental and economic impacts.

The following Table provides a listing of recent permit applications for coal-fired facilities burning PRB or low sulfur coal only. Only 5 out of the 16 systems identified have installed a wet FGD for SO_2 control.

Table 2: SO_2 Limits & Control Technology of Recent PRB or Low Sulfur Coal Burning Power Plants

Unit. Location	State	Date of Permit Issuance	SO_2 limit (lb/MMBtu)	Control Technology
City Public Service of San Antonio, Spruce 2	TX	Permit issued.	0.06 (annual) 0.10 (30-day)	Wet FGD
Desert Rock	NM	Proposed	0.06 (24-hr)	Wet FGD / lime injection
Longleaf Energy Associates	GA	May 2007	0.12 (24-hr) 0.065 (30-day) for S% < 0.4% 0.09 (30-day) for S %> 0.4%	Dry FGD
Newmont Mining, TS Power Plant	NV	October 2007	0.065 (24-hour) for S% < 0.45% 0.09 (24-hour) for S %> 0.45%	Dry scrubber
Hugo Unit 2	OK	Permit issued	0.065 (30-day)	Wet FGD
Intermountain Power Service Corp	UT	October 2004	0.09 (30-day) 0.10 (24-hr)	Wet FGD
City Utilities of Springfield, Southwest Power Station	MO	December 2004	0.095 (30-day)	DLS / Spray dryer absorber
Omaha Public Power District	NE	March 2005	0.095 (30-day)	Dry FGD
NRG Energy, Inc., Big Cajun II Generating Station	LA	August 2005	0.10	Wet FGD
Wisconsin Public Service Corp., Weston Unit 4	WI	October 2004	0.10 (annual) 0.09 (30-day) 90% removal (30-day)	Dry FGD
LS Power, Sandy Creek Energy Station	TX	Permit issued	0.10 (annual) 0.12 (30-day) 0.3 (1-hr)	Dry FGD
Mid American Energy Company, Mid American Unit 4	IA	June 2003	0.10 (30-day)	Dry FGD
Black Hills Power and Light (Wygen 2)	WY	July 2005	0.10 (30-day) 0.36 (1-hr)	Spray dryer/absorber
Xcel Energy, Comanche Station	CO	July 2005	0.10 (30-day)	Dry FGD
Municipal Energy Agency	NE	March	0.12 (30-day)	DLS/SDA

– Hastings		2004		
LS Power, Plum Point Power Station	AK	August 2003	0.16 (3-hr)	Dry FGD

One can make the argument that using dry FGD on large coal-fired boilers firing low-sulfur coal would be the normal case and using wet FGD would comprise of more unique occurrence. Based on the recently issued permits above, the superior control of SO_2 with wet FGD is not translatable into the limits shown above. A review of other recently issued permits not necessarily firing low sulfur coal also do not reveal any other limits lower than those stated above although higher removal efficiencies may have been permitted. Since differences between permitted outlet emissions rates between wet FGD over low FGD seem to be slight, it seems appropriate to give economic, energy, and environmental impacts greater weight.

Under this comment, Wash U alleges that MDNR rejected the NO_x economic analysis for various reasons citing MDNR correspondences and the NO_x BACT analysis in the draft permit. They use these documents as support for rejecting the use of economic analysis in the SO_2 BACT analysis. MDNR's reasoning behind using economic analysis for SO_2 and not NO_x is explained as follows. For NO_x, AECI had chosen the top technology and was intending to use the economic analysis to set a NO_x limit. During the initial portion of the NO_x BACT review, several questions came up with regards to the economic analysis conducted by AECI. However, during the course of the analysis, AECI voluntarily agreed to the lower the NO_x limit which eliminated the need for further review of the economic analysis. MDNR did not reject AECI's economic analysis in as much as MDNR did not rely on AECI's economic analysis because they willingly accepted the lower limit. To further clarify, MDNR did not disagree with AECI on the use of average annual cost effectiveness or incremental costs; MDNR did disagree with AECI on directly comparing average annual effectiveness cost to incremental cost. For SO_2, AECI used the economic analysis to distinguish between the top two control technologies: dry FGD and wet FGD, not to set a limit. The SO_2 economic analysis is more complicated than the NO_x since not only are you looking at the cost difference of the two technologies, you are also considering the impacts of sulfur content of the coal.

AECI updated their cost analysis for FGD on August 9, 2007. (As previously stated, these numbers were inadvertently left out of the draft document.) In the original BACT, the removal efficiency of the wet FGD was evaluated at 94%. The updated BACT economic analysis was conducted using the wet FGD efficiency of 95.2%. The increase in efficiency of 1.2% and the increase in construction costs since the time of the original submittal of the SO_2 economic analysis raised the total annual costs to $43,707,000 compared to $26,690,000 in the original evaluation. The incremental cost for wet FGD with the new efficiency compared to dry FGD is $20,290 per ton compared to $10,720 per ton in the original BACT analysis.

Table 3: SO_2 Annual and Incremental Cost Effectiveness

Control Technology	Total Annual Cost ($/year)	Annual Emission Reduction (tpy)	Average Annual Cost Effectiveness ($/ton)	Incremental Annual Cost Effectiveness ($/ton)
Wet FGD + WESP	$49,499,400	35,728	$1,383	$30,840
Wet FGD	$43,707,000	35,791	$1,221	$20,290
Wet FGD*	$44,525,600	35,791	$1,244	$21,741
Dry FGD	$32,044,400	35,216	$910	--

*This includes costs associated with treating waste water stream.

It is estimated that a wet FGD technology creates a need for an additional 435,000,000 gallons of water each year. This is approximately 30% more water than the dry FGD. The wet FGD also creates a need for a dedicated treatment facility to treat an additional water waste stream. The facility would add an additional capital costs ranging from $5.5 to $10 million depending on the wastewater flow, chloride concentration in the FGD reagent and discharge. Water treatment would add an additional $250,000 in annual operating costs to the project.

Wash U gives three reasons why the incremental cost effectiveness of wet scrubbing compared to dry scrubbing is overestimated.

First they state that the assumption for control efficiency of 94% is too low to satisfy BACT. As mentioned above, this was changed to 95.1%, which based on their comments would still be too low. (Response to control efficiency used for wet FGD is addressed in other responses.) Wash U also state that “the cost effectiveness would be much lower as a 98% scrubber removes three times as much sulfur as a 94% scrubber while the costs would only increase by about 20%”. This is inaccurate. A 98% scrubber would removes only 4% more SO_2 than a 94% scrubber.[10] Lastly, they state that “the [economic] costs are not based on a 100% capacity factor”. According to Appendix B-10 and B-19 of AECI’s construction permit application, the economic costs are based on a 100% capacity.

The second reason given is that they imply AECI did not supply the basis for the cost of each major piece of equipment. However, AECI is very clear in its BACT write-up that costs were estimated using U.S. EPA’s CUECost estimating worksheets following to the best extent possible the methodology laid out in U.S.EPA OAQPS Control Cost Manual, as accepted by the NSR Manual (page B.26). The basis for O&M costs are given in Appendix B of the construction permit application.

The third reason they state is that the costs of the wet FGD are overstated. Wash U provides one example, a comparative cost analysis performed by Burns & McDonnel where they compared life-cycles costs of wet FGD to dry FGD and found that the life-cycles costs were only 7% more for the wet FGD. MDNR reviewed the study and found that it contained a lot of useful information. However, to use only one source to say that wet FGD costs are overstated is presumptuous especially when in the study itself says the EPRI IECCOST model accuracy is +/- 20 to 25 percent for the Total Installed Cost estimates. This study was for a retrofit where site specific factors can come into play. Small changes in either estimate of wet or dry FGD can result in a wider differential. Sargent & Lundy also performed a study comparing the costs of dry FGD systems and wet FGDs (Wash U Ex. 100). Their conclusion, at p. 52, says that for PRB coal, at either 400 MW size or 500 MW size, regardless of how the by-product is disposed, the FGD technology ranking is 1. (tie) Lime Spray Dryer, 1 (tie) Circulating Dry Scrubber, then 3. Limestone Forced Oxidation.

Energy impacts include the use of auxiliary power. The additional auxiliary power for wet FGD is needed to process limestone which requires larger grinding equipment (ball mills), slurry pumps, air compressors, vacuum pumps, and booster fans. This increase in power usage increases the amount of fuel that will be necessary at this or another plant to meet electrical utility demands. AECI estimates that use of a wet FGD requires an additional 0.7% of the unit gross output for operation. Heat input to the main boiler would need to increase by approximately 1.5% with the wet FGD to achieve the same net plant output. The energy impacts were factored into AECI’s economic analysis as suggest by the NSR manual at B.30.

> “If such benefits or penalties exist, they should be quantified. Because energy penalties or benefits can usually be quantified in terms of additional cost or income to the source, the energy impacts analysis can, in most cases, simply be factored in the economic analysis.

The environmental impacts of dry FGD systems are not the same as those from wet FGD systems. Below is brief outline of some of the environmental impacts and benefits of both.

Environmental impacts and benefits of wet FGD:

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[10] 6,872 MMBtu/h x 1.23 lb/MMBtu = 8,452 lb/hr SO_2,
At 94% removal: 8,452 x 0.06 = 507 lb/hr SO out => 8,452 – 507 = 7,945 lb/hr removed,
At 98% removal: 8,452 x 0.02 = 169 lb/hr SO_2 out => 8,452 – 169 = 8,283 lb/hr removed,
8,283 / 7,945 = 1.04 or a 4% increase.

- Wet limestone FGD can produce commercial-grade gypsum and allows for the reuse of the fly ash.
- The reagent stoichiometric ratio for a wet limestone FGD system is lower than a dry FGD system.
- Wet FGD systems are generally perceived to have higher SO_2 removal rates; however, the degree is believed to be dependent on the inlet SO_2 content.
- Wet FGD systems are more tolerant of changes in the sulfur content in the fuel than dry FGD systems.
- Wet scrubbers produce a scrubber blowdown waste stream with potentially high chloride content that must be disposed.
- Wet scrubbers require considerably more water than dry scrubbers.
- A wet scrubber is placed downstream of the particulate control device; therefore any saturated droplets or particulates emitted from the wet scrubber are emitted to the atmosphere, increasing the PM_{10} emission rate as well as trace metal constituents contained in the particulate matter.
- There is often a vapor plume since the exhaust flow is saturated.
- A wet scrubber uses limestone, which is generally stored in piles on-site. The handling, crushing and transferring of limestone, generates larger amounts of particulate emissions. For the dry scrubber, the lime feed is contained in controlled silos, for use in mixing with the scrubber slurry.
- If an adequate local market is not available, the gypsum by-product will require dewatering and proper disposal.

Environmental impacts and benefits of dry FGD.

- Reagent utilization for a dry system is poorer compared to a wet limestone system.
- There is the potential for high short-term SO_2 emission rates due to atomizer change-out of a dry scrubber.
- Dry FGD produces a by-product that has fewer uses due to its properties, i.e. mixed ash/by-product, permeability, soluble products, such as calcium chloride. Combined removal of fly ash and by-product solids in the particulate collection system precludes commercial sale of fly ash. However, the material does not require dewatering and is easily landfilled.
- Use of a lime spray dryer with a fabric filter results in signification reduction in gaseous oxidized mercury emissions.
- Sulfuric acid mist as well as sulfur trioxide is removed more effectively with dry FGD systems than wet FGD systems.
- There is a reduced or eliminated vapor plume since the exhaust flow is not saturated.
- Overall power consumption is lower for dry technologies than for wet FGD systems which lead to less collateral pollution from usage of more power.
- The dry scrubber reduces water consumption and minimizes water handling. A dry FGD system can provide an outlet for process wastewater from other parts of the power plant. Since the dry FGD system evaporates all its water, the heavy metals, including oxidized mercury, report to the FGD by-product. The by-product tends to trap the trace metals and the concentrations are low enough to qualify the by-product for standard landfill (Wash U. Ex 100).

- There is no liquid waste from a dry FGD system
- PRB coal is especially suited for dry scrubbing systems utilizing flyash/byproduct recycle. This takes advantage of the CaO_3 in the PRB fly ash to reduce the consumption of fresh lime reagent and reduce overall waste product projection.

Many of these environmental impacts can also be reflected in the economic analysis such as reagent and water usage. Some of the advantages such as wet FGD's flexibility in adjusting to changes in sulfur are mitigated by the fact that AECI will be operating under a fairly narrow sulfur content range (0.2 to 0.5% sulfur). Also, if there is no gypsum market, then the gypsum by-product goes from an advantage to disadvantage. According to Wash U's Ex. 100, "the market for wallboard-grade gypsum is becoming saturated in many locales, which diminishes their opportunity". In another paper, "over the next 20 years the North American supply of byproduct gypsum is going to exceed the demand by a wide margin with a surplus of 10-15 million tons per year by 2015" if other uses are not found.[11]

According to Wash U comments, the water impacts of wet scrubber are overstated. One source is cited which compares water usage on a gallon of water consumed per pound of SO_2 removed. However, further review of the source shows that amount of SO_2 removed for each system was based on two different scenarios: the wet FGD was controlling emissions from a 500 MW burning 4.1% sulfur coal and the dry FGD was controlling emissions from a 500 MW boiler burning 0.44% sulfur coal. A comparison between gallons of water used per pound of SO_2 removed is not valid especially when the amount to inlet SO_2 to the wet FGD system is close to 10 times more than into the dry FGD and is largely independent of the amount of SO_2 removed.

Wash U states that the Review Summary "alleges with no support that wet FGD alone would have increased PM emissions due to increase in SAM emissions and potentially other condensibles". According to Ex. 100, at p. 11,

> "Sulfur trioxide (SO_3), which condenses to sulfuric acid aerosols in an FGD system, is removed efficiently (greater than 90%) with a dry FGD baghouse. Wet scrubbers have less affinity for acid mist and, according to FGD suppliers, they typically capture between 25% and 50% of sulfuric acid aerosol. Alkali injection upstream of a particulate collection system or even the addition of wet electrostatic precipitator would be required for a wet limestone FGD system to achieve the same level of acid mist removal as the inherent removal in a dry FGD system."

In addition, since the stream leaving the wet FGD is saturated, the evaporation of water vapor in the exhaust stream can result in small PM emissions from minerals contained in the water. MDNR agrees that the amount of SO_3 and ultimately sulfuric acid mist (SAM) to the stack will be small due to the low sulfur content of the coal and the reactive nature of the PRB coal; however only a small amount of SAM is needed to create a pale plume visible after the water vapor plume dissipates and to cause corrosion problems downstream of the FGD system. To disprove the claim made in the review summary, Wash U cited the article, An Updated Method for Estimating Sulfuric Acid Emissions From Stationary Power Plants at Exhibit 230.; however verification of their statement that "combined control of the upstream baghouse and wet scrubber achieves about the same or better SAM control than the dry scrubber and baghouse" could not be made.

MDNR has reviewed several documents related to the efficiencies of wet and dry scrubbing. Due to the low sulfur content of the Powder River Basin coals, MDNR believes that dry FGD is an appropriate selection for this project. The typical coal to be used at the proposed AECI boiler will have a sulfur content of approximately 0.3 wt% with a maximum of 0.5 wt%. Since there is little experience with wet FGDs operating with very low sulfur fuels, it is difficult to set a limit that MDNR and AECI believes can be maintained on a continuous basis. According to our analysis, wet FGD resulted in a 4% increase in SO_2 removed versus the dry FGD with an incremental cost in excess of \$20,000. Due to uncertainties of actual performance of wet FGD with low PRB coal

[11] Bob B. Bruce PhD and David L. Tackett, Balancing Supply and Demand of Flue Gas Desulfurizatin Gypsum in USA/Canada, 2004

in addition to the energy, environmental and economic impacts, MDNR agrees with AECI's analysis that dry FGD is the BACT SO_2 control technology.

Comment X.C.2: Lower emission limits for SO_2 have been permitted.

MDNR Response: Wash U points out several facilities that have been proposed or permitted with lower SO_2 emission limits:

- Longleaf Energy Station in Georgia has proposed a dry FGD with a tiered 30-day rolling average SO_2 limits.
  - 0.065 lb/MMBtu for uncontrolled SO_2 less than 1.0 lb/MMBtu
  - 0.08 lb/MMBtu for uncontrolled SO_2 less than 1.25 but greater than 1.0 lb/MMBtu
  - 0.105 lb/MMBtu for uncontrolled SO_2 less than 1.6 but greater than 1.25
- LS Power White Pines Energy Station in Nevada has proposed a dry FGD with a 30-day rolling average of 0.065 lb/MMBtu.
- T-S Power Newmont Mining in Nevada has a dry FGD with a tiered 24-hour rolling average SO_2 limits.
  - 0.065 lb/MMBtu when sulfur content is less than 0.45%
  - 0.09 lb/MMBtu when sulfur content is greater than 0.45%
- Springfield City Water, Power and Light – Dallman Unit 4 in Illinois has proposed a wet FGD with SO_2 with 30-day rolling average limits.
  - 99% removal exclusive of startup/shutdown
  - 98% removal inclusive of startup/shutdown

Other recent pulverized coal SO_2 BACT determinations are shown in Table 2 of this Response to Comments.

None of the facilities above have been constructed and thus have not demonstrated the ability to achieve these SO_2 limits on a long-term basis. In addition, the Dallman Unit is firing high-sulfur bituminous coal (approximately 3.5%) which is not comparable to the maximum sulfur content of 0.5% as proposed by AECI and is using a wet FGD to control SO_2 emissions.

MDNR acknowledges that the existence of these limits play a large role in determining a BACT limit. However, without the presence of data showing that these limits are continually achievable and consideration of technical data present by AECI (discussed in Comment X.C.1.iii), MDNR believes that the higher limits given in the permit are valid.

Comment X.C.3: Lower emission limits for SO_2 have been achieved.

MDNR Response: Wash U lists several units that are achieving limits lower than AECI's lowest proposed limit of 0.07 lb/MMBtu. Further review of these units show considerable differences to that proposed by AECI. The Navajo Generation Station in Arizona uses a wet FGD to control the SO_2. The Reid Gardner units are small units (100 MW) and use wet sodium-based scrubbing to control the SO_2. Lastly, the Altavista Power Station units are stoker boilers which are 71MW in size, almost 10 times smaller than AECI. MDNR is not aware of any units firing PRB coal and using dry FGD that demonstrate SO_2 levels below 0.07 are achievable on a consistent basis.

Comment X.C.4. (excerpts): The SO_2 BACT limit must be enforceable. The compliance method for the proposed Norborne power plant as described in the draft permit is not adequate to determine continuous compliance…. The sulfur content sampling frequency is not frequent enough to determine where in the sulfur content tier the coal is located…. The permit should require continuous collection of samples and analysis of a daily composite or use of an XRF or other instrument capable of making continuous measurements of coal sulfur content.

> **MDNR Response:** The draft permit under Special Condition 11 allows for the sampling of coal to determine the fuel sulfur content. According to the Special Condition, AECI must perform daily fuel sampling and averaged on a 30-day basis. The coal sample will taken from conveyor C-7 which is directly before the input into the boiler and best reflects the coal that will be burned in the boiler thus ensuring the 30-day rolling sulfur content average corresponds to the same 30-day SO_2 emission limit given in Special Conditions 1.F. After a full twelve months of operation, AECI may submit a variability analysis on the sulfur content of the coal to the Director of the Air Pollution Control Program of MDNR. If approval by the Director is given, the daily sampling may be replaced by periodic sampling. MDNR believes that 12-months of daily sampling is an adequate timeframe for AECI to analyze the variability of the sulfur content in the coal. MDNR retains the right to deny periodic sampling in the event that the variability analysis does not sufficiently satisfy MDNR's assurance level.
>
> In the draft permit, MDNR stated that if there is deviation between two consecutive samples of more than 20%, then AECI must return to daily sampling until there are 30 days of sampling with no deviation. Upon further consideration, MDNR feels that a percent deviation is not appropriate since as the sulfur content increases, the allowable deviation also increases. (E.g. 20% deviation of 0.2% sulfur content is 0.04%, i.e. the allowable sulfur content could be up to 0.24% without triggering daily sampling, whereas, 20% of 0.4% sulfur content is 0.08%, i.e. the allowable sulfur content could be up to 0.48% without triggering daily sampling). Therefore, MDNR will replace the 20% deviation with allowing no more than +/- 0.04% change in fuel sulfur content.
>
> There are several issues regarding inlet CEMS for determining continuous compliance for determination on inlet tier status. First, sulfur capture/retention in the fly ash can lower the SO_2 content of the flue gas below the ASTM predicted level. The extent of sulfur retention in the ash will depend upon ash composition and boiler operating conditions and is difficult to accurately predict from ash analysis alone. Reliable measurement of inlet SO_2 becomes problematic with a reactive fly ash such as is common with PRB coal. The SO_2 in the flue gas reacts with alkaline components of the ash deposited on the probe filter resulting in a "false low" inlet SO_2 concentration. The environment at the inlet to an SO_2 control device is relatively harsh (e.g. higher temperature, duct velocity and particle impact) as compared to stack conditions. The instrument error effect resulting from these factors is magnified if the CEMS unit is not constantly maintained to avoid problems with low instrument air pressure, high moisture air, particle build-up, and sample line temperature variation. Further, low (instrument) biasing could put the facility in a lower compliance tier when the "true" tier would correspond to a higher inlet value,[12]
>
> The inlet sulfur content which set the outlet SO_2 rate are relatively small numbers ranging from typical contents of 0.2% to 0.4% by weight. MDNR is satisfied that variation of less than plus or minus 0.04% is adequate to capture the true SO_2 content of the coal.

Comment D: The Stated BACT Limits for Sulfuric Acid Mist (SAM) Emissions from the Main Boiler Do Not Reflect BACT. Comment D.1: The test method for SAM is wrongly used to justify a less stringent permit limit.

> **MDNR Response:** In the past, construction permits have included specific test methods and emission limits as part of the special conditions portion of the permit. Currently, only emission limits are listed in the permits and test methods for compliance purposes are now determined through discussions, based upon 10 CSR 10-6.030 with representatives of the Compliance Section prior to testing at the installation. This change was instituted to allow for determination of the most appropriate method to demonstrate compliance considering an installation's specific operating parameters in cases where more than one test method is available. In addition, promulgation of new methods or changes to existing method that occurred between permit

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[121212] Letter from AECI to MDNR regarding Information Concerning the AECI Norborne Project – SO_2, NO_x and PM_{10} Permit Limits dated February 14,2007.

issuance and the dates of compliance testing no longer necessitated amending the construction and operating permits. As such, the permit issued by MDNR to AECI will not state specific test methods in the special conditions. However, a list of all test methods allowed under Missouri state regulations are listed under 10 CSR 10-6.030 Sampling Methods for Air Pollution Sources. MDNR is required by this rule to follow 40 CFR part 60, Appendix A – Test Methods, Method 8 – *Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources* to show compliance with the SAM emission limit. Therefore, unless there is promulgation of a new test method for determining emissions of SAM or changes to the current test method, Method 8 will be used by AECI to demonstrate compliance with their SAM emission limit. Method 8 is the only method that EPA has published for measuring sulfuric acid/sulfur trioxide emission. Our current rules do not allow for an alternative. Therefore, any biases associated with Method 8 should be considered when setting an emission limit for SAM.

Comment D.2: The SAM emission limit is not based on the maximum degree of reduction.

MDNR Response: One of the assumptions used to calculate the SAM emission rate is that 2.0% of fuel SO_2 will be converted to SO_3 in the boiler and the SCR. Wash U argues that this percentage could be low as 1.2%. However, part of their reasoning is dependent on using a specialized catalyst in the SCR that limits conversion of SO_2 to SO_3. The documents provided to support the use of catalyst capable of a low conversion rate of 0.5% were vendor-generated. Whereas vendor data, brochures, and papers provide valuable information, it is difficult in many cases to use this information to set a limit that will have to be met for the lifetime of the plant. According to Wash U Ex. 176, SO_3 production from combustion ranges from 0.3 to 0.6% and SO_3 production from SCR NO_x control ranges from 0.5% to as high as 3%. Therefore, total SO_3 production can be as little as 0.8% to as high as 3.6%. A conversion of 2% SO_2 to SO_3 is a common assumption used in the industry.

Regardless, AECI has proposed the combination of dry FGD and the fabric filter baghouse which is the most effective H_2SO_4 control. The statement by Wash U that a control efficiency of greater than 95% is based on Wash U Ex. 175 which is a vendor brochure that gives no actual data, no inlet SO_2 information and no plant names in order to verify its accuracy.

Wash U list several other permits that have SAM limits lower than that proposed by AECI. With regards to the City Utilities in Springfield, MO, the BACT Analysis of the permit explains that the 0.000184 lb/MMBtu SAM limit given in the City Utilities' permit was proposed by the applicant and did not undergo a BACT evaluation. That limit was determined using the assumption that a different method for testing was going to be used to show compliance. City Utilities is currently under construction and have not demonstrated compliance. However, AECI will be required to demonstrate compliance using Method 8. The other limits listed in three other permits ranges from an equivalent of 0.00036 to 0.0015 lb/MMBtu. No data was presented to show that these limits are actually achievable and MDNR is not aware of any data that shows these limits are achievable.

Although there are several permits with lower SAM limits, MDNR is not aware of any test data that shows compliance with such limits using the EPA Method 8. Wash U have supplied many documents in which it is stated that SAM from a boiler firing PRB coal is expected to have minimal to no emissions from the stack due to the use of dry FGD with fabric filter and the alkalinity of the fly ash that is associated with burning PRB coal. In addition, AECI is proposing the most effective control technology for SAM. MDNR is not aware of any further controls that can be added to enhance SAM removal. Therefore, in light of the limitations of Method 8 and lack of actual data, MDNR will leave the SAM limit at 0.0038 lb/MMBtu.

Comment E.1: The Stated BACT limits for Total PM_{10} Emissions from the Main Boiler Do Not Reflect BACT. The BACT analysis uses flawed calculations and reasoning to determine the condensable fraction of PM_{10}.

MDNR Response: The BACT limit for total PM_{10} was originally calculated by summing the filterable PM_{10} limit and the limits of those constituents that were believed to make up condensable PM_{10}. These included SAM, HF, HCl and VOCs. Therefore, the condensable PM_{10} (CPM) limits was derived as follows:

Filterable PM_{10}	0.012 lb/MMBtu
SAM	0.0038 lb/MMBtu
HF	0.0011 lb/MMBtu
HCl	0.0034 lb/MMBtu
VOC	0.0036 lb/MMBtu
Total PM_{10}	0.0239 lb/MMBtu

Upon further review of the comments, MDNR agrees that HCl and HF by themselves are not components of CPM. MDNR has found some references to HCl or HF possibly combining with NH_3 to form a condensable salt. However, according to AECI's submittal, NH_3 slip is expected to be a maximum of 10 ppm and H2SO4 can also react with it to form (NH4)2SO4. Even if all NH3 is converted to a salt, this would equate to a bias of approximately 0.002 lb/MMBtu of (NH4)2SO4 with no ammonia left to react with the HF or HCl. If MDNR was to use the same approach as above, the CPM limit would then become 0.02 lb/MMBtu as shown below.

Filterable PM_{10}	0.012 lb/MMBtu
SAM	0.0023 lb/MMBtu
$(NH_4)_2SO_4$	0.002 lb/MMBtu
VOC	0.0036 lb/MMBtu
Total PM_{10}	0.020 lb/MMBtu

See response to Comment E.4 for further discussion.

Comment E.2: The test method for total PM_{10} is wrongly used to justify a less stringent permit limit.
Comment E.3: Lower total PM_{10} emission limits have been permitted.
Comment E.4: Lower total PM_{10} emission limits have been achieved.

MDNR Response: See Response to Comment D for explanation on why test methods will not be included in the PSD permit.

All test methods allowed under Missouri state regulations are listed under 10 CSR 10-6.030 Sampling Methods for Air Pollution Sources. MDNR is required by this rule to follow 40 CFR part 51, Appendix M – Test Methods, Method 202 – *Determination of Condensible Particulate Emissions from Stationary Sources* to measure CPM emissions. Therefore, unless there is promulgation of a new test method for determining emissions of CPM or changes to the current test method, Method 202 will be used by AECI to demonstrate compliance. Our current rules do not allow for an alternative. Therefore, any biases associated with Method 202 will be considered when setting an emission limit for CPM. However, MDNR maintains its original position as stated in a letter from James L. Kavanaugh, Director of the Air Pollution Control Program, to Todd A. Tolbert of AECI that "Method 202 is currently the sole method for demonstrating compliance with condensible particulate emission limits. Should there exist any biases in the method, those biases affect every installation in each industry using the method for compliance purposes. Emission limits found in permits nationwide will reflect any potential biases" (Wash U, Ex 188).

MDNR also maintains its original standpoint that a "valid comparison cannot be made with other plants that allow modifications to Method 202" (p 48 of BACT analysis in draft permit). However, in the draft permit's BACT Analysis, MDNR also continues to state that "what remains available for comparison is a small handful of plants that have proposed or been permitted with a total PM_{10} limit equal to 0.18 lb/MMBtu using unaltered Method 202 for compliance. These plants have not yet begun operation; attainment of such low total PM_{10} limits has not yet been demonstrated".

However, that being said, Wash U provided actual data showing that a total PM_{10} limit of 0.018 lb/MMBtu using an unmodified Method 202 is achievable. The data provided was from Unit 5 of the Kansas City Power & Light Hawthorn Generating Station in Kansas City, MO. The data over the past 6 years have Total PM_{10} emissions ranging from 0.013 to 0.017 lb/MMBtu. Therefore, because there are several other facilities with total PM_{10} limits of 0.018 lb/MMBtu and because there is actual data using an unmodified Method 202 showing that this limit is achievable, MDNR is modifying the Total PM_{10} limit to 0.018 lb/MMBtu. To account for the lowering of the Total PM_{10} rolling average, the Total PM_{10} limit based upon a 24-hour period and inclusive of start-up and shutdown, as given Special Condition 1.F.3)c), has been lowered to 123.7 lb/hr from 163.9 lb/hr,

Comment F.1: The Stated BACT Limits for Carbon Monoxide (CO) Emissions from the Main Boiler Do Not Reflect BACT. The CO emission limit is not based on the maximum degree of reduction.

MDNR Response: Both CO and VOC emissions are products of incomplete combustion. CO and VOC formation is minimized when the boiler temperature and excess oxygen are adequate for complete combustion. However, adjusting temperature and excess oxygen in order to minimize the formation of CO and VOC tends to promote the further formation of NO_x. Therefore, a balance between acceptable CO-VOC and NO_x emissions must be made.

The BACT emission limit for CO is 0.15 lb/MMBtu, based on a 30-day rolling average. In addition the BACT limits for NO_x is 0.05 lb/MMBtu, based on a 12-month rolling average and 0.065 lb/MMBtu, based on a 30-day rolling average. AECI will demonstrate compliance for CO and NO_x on a continuous basis using CEMs. Further examination of AECI's BACT analysis, Table A-4 show that no other facilities with lower CO emission limit have higher NO_x rates.

Table 4: Recent Pulverized CO and NO_x BACT Determinations*

Permit Date	Facility Name	State	CO Limit (lb/MMBtu)	NO_x Limit (lb/MMBtu)
7/5/05	Comanche Unit 3	CO	0.13	0.08 (30-day)
4/28/05	Prairie State Energy Center	IL	0.12	0.10
3/2/04	Longview Power	WV	0.11	0.08
1/14/04	WE Energies Elm Road Station	WI	0.12	0.07 (30-day) 0.07 (annual)
5/29/03	Two Elk Power Plant	WY	0.135	Couldn't find permit.
10/11/02	Thoroughbread Generating Station	KY	0.10	0.07 (30-day)

*See AECI's BACT Analysis, Table A-4 for the complete list.

Since there is a trade-off that occurs between NO_x and CO, an emission limit for CO can not be made with regard for the NO_x limit also. Although AECI has a 30-day emission limit of 0.065 lb/MMBtu, this level of NO_x emissions is even more constrained by the 0.05 lb/MMBtu annual limit.

Comment G: The Stated BACT Limits for Volatile Organic Compound (VOC) Emissions from the Main Boiler Do Not Reflect BACT

MDNR Response: Both CO and VOC emissions are a products of incomplete combustion. Unfortunately, the mechanisms used to reduce CO and VOC tend to increase NO_x formation. Therefore, good combustion practices are used to minimize CO and VOC emissions and constitute BACT control. Combustion controls have been identified as BACT for VOC in every permit issued for a coal-fired boiler. Since compliance with VOC emission limits are based typically once a year performance tests, there is very limited performance data from existing boilers.

Because of the lack of data, AP-42 emission factors were relied on to develop the proposed VOC emission rate and limit. Although AP-42 is typically an average rate, they are based on actual performance tests with no margin included for compliance. MDNR and AECI were unable to obtain a copy of the source for AP-42 VOC emission factors. The source cited in AO042 for the VOC emission factor is “Atmospheric Emissions from Coal Combustion: An Inventory Guide,: 999-AP-24, U.S. EPA, Washington, DC, April 1966. It is presumed that the emission factor source was based on EPA approved test methods. Review of other permitted boilers has not revealed any other emission factor source for VOC. Without any other sound sources of emission information and because of the fact that virtually all other coal-fired boilers have relied on AP-42 to establish their AP-42, MDNR believes the use of the AP-42 emission factor, in this case, is acceptable.

Wash U has included several plants that have lower VOC emission limits. It is clear from analysis provided to MDNR by AECI that these plants with lower limits have also relied on AP-42 to set their limits. The variance in the emission rate in lbs of VOC/MMBtu of these plants with AECI is attributable to the variance in heating values (HVs) of the coal. The AP-42 emission factor is equal to 0.06 lb VOC/ton of coal. For AECI, the calculation of the VOC emission rate in terms of lb/MMBtu is as follows:

- 8,100 Btu/lb of coal x 2000 lb/ton x 1 mmBtu/10^6 Btu = 16.2 MMBtu/ton of coal
- 0.06 lb VOC / ton of coal x 1 ton of coal / 16.2 MMBtu = 0.0037 lb/MMBtu
- AECI’s VOC emission limit is slightly lower at 0.0036 lb/MMBtu

For other facilities, the VOC emission rate was calculated also based on the AP-42 and the coal heating value.

- Intermountain Unit 3: Heating value = 11,936 Btu/lb (23.9 MMBtu/ton). 0.06/23.9 = 0.0025 lb/MMBtu. They added a margin of compliance for proposed VOC BACT limit in their permit of 0.0027 lb/MMBtu.
- Santee Cooper boilers: Estimated heating value based on coal shipments to existing facility = 25.2 MMBtu/ton. 0.06/25.2 = 0.0024 lb/MMBtu. This is the limit proposed in their application
- City Public Services of San Antonio: Proposed firing PRB coal. Could not identify the heating value of the coal, but they proposed a limit of 0.0036 lb/MMBtu on 1-hr basis (which is the same as AECI) and 0.0025 lb/MMBtu on annual average.. Could not identify how City Public Service was going to demonstrate compliance with the VOC annual average.
- Roundup Power: Heating value = 9,916 Btu/lb (19.83 MMBtu/ton). 0.06/19.83 = 0.003 lb/MMBtu. This is the permitted limit.
- Other units with proposed emission rates that appear to have been based on AP-42 include LS Power Longleaf, Sandy Creek Energy, Hugo Unit 2, Iatan Generating Station, Comanche Unit 3, Nebraska City Unit 2, City Utilities of Springfield, Longview, Elm Road, Holcomb Unit 2, and Council Bluffs Unit 4. All of these units have proposed VOC emission rates in the range of 0.0034 to 0.0036 lb/MMBtu.

With regards to actual emissions, Hawthorn Station Unit 5 has demonstrated a VOC emission rate below 0.0036 lb/MMBtu for the last five years. Three tests conducted in one day were averaged over 180 minutes each for each of these years. However, MDNR does not believe tests conducted over one day at one facility is an adequate amount of information to set a lower limit for VOC. AECI will have to continuously balance CO emissions limits (and as a result VOC emissions) with a very low NO_x emission limit (0.05 lb/MMBtu on an annual basis).

AECI is required to show CO compliance on a continuous basis with a CO CEM system. Since AECI is constantly being monitored for CO, AECI is insured of continually operating its combustion controls effectively which will ultimately ensure that VOC emissions are also minimized.

Based upon the above explanations, MDNR believes that 0.0036 lb/MMBtu is reflective of BACT controls for VOCs.

Comment H: The BACT Analysis Fails to Address Carbon Dioxide Emissions

MDNR Response: Please see MDNR's Response to Wash U, Comment III.

The following are written comments submitted to the Air Pollution Control Program by private citizens. The comments will be paraphrased below due to the length of the comments. The original comments may be read in full in the Attachments. Several of the comments submitted by private citizens have been addressed in response to Wash U's written comments and will not be repeated here.

Comment Letter from Gerhardt List (Summary): Author had concerns with the Environmental Impact Statement and lack of cumulative impacts analysis.

> **MDNR Response:** MDNR has reviewed and issued this permit with the authority granted by federal and state regulations. The issues raised regarding the Environmental Impact Statement falls outside the Air Pollution Control Program's purview.
>
> A modeling analysis on Class I areas as well as an Additional Impact Analysis was conducted to address potential impacts. Please see the Modeling Memorandum attached to the final permit for further discussion

Comment Letter from John Greer (excerpts): "Requiring this post-construction ambient air monitoring is unnecessary and will further drive up the cost of the new power plant and in turn the cost of electricity for rural electric cooperative members across Missouri. Since ozone in the vicinity of the Norborne plant comes from various emissions sources within the Kansas City metropolitan area, the responsibility to monitor related impacts should fall on Kansas City residents…":

> **MDNR Response:** AECI, like all major PSD projects, was required to conduct one year of pre-construction monitoring for PM_{10}, SO_2, and ozone. During the course of this monitoring there was an exceedance of the ozone standard. This is not a violation of the ozone standard. You must have three consecutive years of monitored exceedances to be a violation. But since AECI will be a large emitter of NO_x and VOCs, precursors to ozone, MDNR has required AECI to at least conduct one year of post-construction monitoring to ensure the quality of the air is safe for the surrounding community. If at the end of the first year no exceedances are reported than AECI can discontinue the monitoring. This is consistent with requirements of other PSD permits in which there were pre-construction monitored exceedances. This has been required based upon guidance from EPA.

Comment Letter from David E. Cupps, DVM (excerpts): "I believe the emissions limits for ash particle from AECI's new power plant are excessive, specifically for unfilterable particles, where an unreliable testing method was used to establish the current limits. DNR should set limits that ensure an adequate margin to satisfy permit requirements."

> **MDNR Response:** MDNR established the Total PM_{10} limit which includes filterable and unfilterable (condensable) PM_{10} in accordance with all state and federal regulations. According to these rules, MDNR is required to determine BACT (Best Available Control Technology) and set the appropriate limit. Potential biases were considered when setting the limits. Please see previous responses to comments for further information.

Comment Letter from Ralph Voss (excerpts): "It has come to my attention that the nitrous oxide emissions limits set for the proposed plant are the lowest anywhere in the country. I think it's very unfair to single out this project for such a costly requirement. It is my understanding that the technology probably does not exist to meet these extremely low limits."

> **MDNR Response:** MDNR established NO_x limits which in accordance with all state and federal regulations. According to these rules, MDNR is required to determine BACT (Best Available Control Technology) and set the appropriate limit(s). Please see previous responses to comments for further information.

<u>Comment Letter from Grover Gamm (excerpts):</u> In general it appears to me that the Missouri DNR has established pollution release limits for the new plant that are based on the lowest possible releases from a variety of plants and fuel types. These extremely low limits might be reachable during short periods of time, but I question the practicality of these limits over the life of the plant."

> **MDNR Response:** MDNR established limits for all applicable pollutants in accordance with state and federal regulations. According to these rules, MDNR is required to determine BACT (Best Available Control Technology) for many of these pollutants and set the appropriate limit(s). MDNR spent extensive time evaluating other limits established in other permits, actual performance data, and technical documents. This included evaluating the data with regards to the appropriate time frames that the limits were set in. Please see previous responses to comments for more detailed information.

<u>Comment Letter from Randy Asbury (excerpts):</u> "It is my understanding that the proposed construction permit for the new rural electric cooperative coal plant proposed for Norborne, Missouri restricts pollution discharge limits to levels below two other recently permitted coal plants in Missouri…. I also understand the two other recently permitted plants are near urban areas. Logically, it seems that plants located in areas with more pollution would be required to maintain stricter air emission controls than plants located in rural areas where little pollution exists. The requirement that a utility plant in a low pollution area is subject to stricter emission standards than one in an urban area is counterintuitive."

> **MDNR Response:** Because AECI will be emitting pollutants above major levels, AECI is required by state and federal regulations to undergo BACT analysis. According to the New Source Review Workshop Manual, the purpose of BACT is to ensure that the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act". The BACT determination made for the other two recently permitted plants, presumably City Utilities of Springfield and Kansas City Power & Light's Iatan, were completed in December of 2004 and December of 2006. In the time since then, more data on actual performance from other facilities, other permitted limits, and additional technical documents have become available. Consideration of this new information has forced some of the limits to stricter levels; this the intention of BACT requirements.
>
> All of the facilities must demonstrate compliance with the National Ambient Air Quality Standards (NAAQS) and increment standards via modeling. Since at the time of permit issuance, all facilities were located in attainment areas, they were subject to the same level of standards. The fact that a facility is located in an urban area as opposed to a rural area is accounted for in the modeling demonstration.

<u>Comment Letter from Nathan White (excerpt)</u>: "I had great concerns in the draft permit with wording that allowed pollution control systems for mercury as optional. The chance for acid rain also concerns me…I believe a more detailed analysis of potential impacts on water bodies and land acidity level should be done."

> **MDNR Response:** As per Special Condition 1.D, AECI will have to use activated carbon or sorbent injection to reduce mercury emissions.
>
> An Additional Impact Study was conducted as part of this permit. Please see the Modeling Memorandum attached to final permit for further discussion

<u>Comment Letter from Karen Saadeh (excerpt):</u> "The [potential emissions] chart does not include Particulate Matter 2.5, which is much more harmful that PM_{10} and is not caught in PM_{10} filters. The EPA has proposed a rule that will establish$_{.5}$ standards under the Prevention of Significant Deterioration program in the New Source provisions of the Clean Air Act. Under the program new 'stationary sources of $PM_{2.5}$ in attainment areas (which Norborn is) must demonstrate that emissions from the proposed construction and operation of the facility will not cause or contribute to an increase above a maximum allowable concentration or increment for particular pollutants."

MDNR Response: MDNR addressed $PM_{2.5}$ in Response to Washington University Comment V. Please see MDNR's response for further detailed information.

Comment: "Why are start-up and shut-down at the AECI proposed Norborne plant completely excluded from the emissions controls and monitoring? If AECI gets to self-define start-up and shut-down for each event, how can the MO-DNR pretend to be regulating emissions?"

MDNR Response: MDNR considered start-up and shutdown (SU/SD) for all major pollutants in the main boiler. Although MDNR did exclude SU/SD from the NO_x 30-day and 12-month rolling average limits, the SO_2 30-day rolling average, and the filterable PM_{10}, filterable PM and Total PM_{10} 3-hour rolling average limits, a ton per year cap inclusive of SU/SD were included for all these pollutants. All other limits for the main boiler are inclusive of SU/SD events. Please see MDNR's Response to Washington University's Comment IX.A.1 for a more detailed response.

In addition, MDNR has provisions at 10 CSR 10-6.050 with respect to start-up, shutdown, or malfunction events.

Comment Letter from Susan White (excerpt): "The permit needs to address items left out of the application like Particulate Matter 2.5, which is much more dangerous than PM 10 and now has control technologies. We can not continue to add toxic mercury, beryllium, and cadmium to out streams and waterways… With coal fired power started before the knowledge of the health risks or the test available to you now, that prove the contamination, past permits were judged on that different level of testing. DNR must consider the new tests and acceptances levels for the lives of future generations of children."

MDNR Response: Please see MDNR's Response to Washington University Comment V with regards to $PM_{2.5}$.

MDNR required AECI to submit a Risk Assessment Level (RAL) compliance demonstration for all hazardous air pollutants (HAPs) as per 10 CSR 10-6.060(12)(J). For all HAPs that exceeded their respective RAL threshold levels, a modeling demonstration of these HAPs was conducted at their maximum emission rates to determine if their respective concentration fell under the RAL levels designated by MDNR. The RAL values that have been determined by the toxicologist are based on a one-in-a-million cancer risk and are concentrations that are not expected to produce adverse human health effects during a defined period of exposure. None of the HAPs concentrations exceed their respective RALs. Please see the Modeling memorandum attached to the final permit for more detailed information.

Comment Letter from Henry Lindley (excerpt): "If this permit is approved and the power plant is to be build and operational, how will these emissions affect our Federal Wetlands Reserve? Does the Missouri Department of Natural Resources have any concern over the health of our natural environment? In order to protect our environment, wouldn't it be more feasible to incorporate more "green" energy, rather than allowing another pollution-spewing coal fired power plant in our state?"

MDNR Response: A modeling analysis on Class I areas as well as an Additional Impact Analysis was conducted to address potential impacts. Please see the Modeling Memorandum attached to the final permit for further discussion.

Please see MDNR's Response to Washington University Comment IV.

Comment Letter from Reid T. Nelson (excerpt): "I saw nothing in the draft permit which took into consideration how close the plant is to major population centers of the Kansas City Metropolitan area, or the it is downwind of Columbia, Missouri. Plants of this nature, which emit such high quantities of fine particulate matter, should not be located near population centers, and the permit should be denied on this basis."

MDNR Response: This facility demonstrated compliance with the National Ambient Air Quality Standards (NAAQS) and increment standards via modeling.

Comment Letter from Virginia Harris

"DNR should deny the air pollution construction permit for this project because of its negative environmental impacts, which are expected to include:

- High levels of PM2.5 and Carbon Dioxide which will harm human health and will harm our population's environment. DNR has the legal power to regulate these pollutants but is proposing not to do so in this case.
- High levels of other air pollutants (Carbon Monoxide Nitrogen Oxides, Sulfur Dioxide, Total Particulate Matter, Coarse Particulate Matter, Sulfuric Acid, Hazardous Air Pollutants, Volatile Organic Compounds, and Hydrogen Chloride) for which DNR is setting limits that do not protect human health.
- Withdrawal of substantial quantities of water from wells constructed at the Missouri River and piped to the plant, during a period of time when drought in the West and Midwest are threatening water supplies needed for agriculture, environmental and species sustainability, and even human drinking water supplies.
- Discharge of heated water to the Missouri River which will harm wildlife and reduce species sustainability.
- Destruction of wetlands by filling sloughs.

MDNR Response: The issues raised in this letter have been addressed in other comments or fall outside the purview of this permit.

Comment Letter from Judith W. Goetting (excerpt): "The risks are great that the landfill will not be as safe as Associated Electric would have us to believe."

MDNR Response: The issues raised in this letter fall outside the purview of this permit.

The following comments were presented to the Air Pollution Control Program during testimony at the **Public Hearing** conducted on November 13, 2007. The comments will be paraphrased or abbreviated below due to the length of the comments. The original comments may be read in full in the Attachments.

Comments from Grace West on behalf of Gerhardt List:

Comment (excerpts): The purpose was to determine the amount and final disposition of emissions from this coal-fired power plant to the environment. With much ado, it fails to meet these requirements. These criteria pollutants; volatile organic compounds, sulfur oxides, nitrogen oxides, particulate matter -- both PM10 and PM2.5 -- and mercury represent significant issue of public concern and scientific debate. Therefore, we recommend evaluating their impacts at various scales; local and deposition area…. Questionable pollutant levels and incorrect meteorological data were plugged into the dispersion modules…. As we all know, KCI data used is not even close to Carroll County. Thus, results are worthless. Furthermore, the modeling should indicate the local and disposition area of all the above criteria pollutants. It does not. Neither were sampling stations established at the necessary locations to validate these modeling suppositions. A normal practice but even more so when incorrect data was input."

> **MDNR Response**: This facility demonstrated compliance with the National Ambient Air Quality Standards (NAAQS) and increment standards via modeling. A modeling analysis on Class I areas as well as an Additional Impact Analysis was conducted to address potential impacts. Please see MDNR's Response to Washington University Comment VIII and the Modeling Memorandum attached to the final permit for further discussion.

Comment (excerpts): "[T]he emissions parameters should include worst case and best case controls efficiency. No one is naive enough to believe controls work at advertised efficiencies all the time. Neither do we know -- even know if NO_x or SO_2 controls will be used if pollutant credits are traded."

> **MDNR Response:** AECI will be required to meet the emission limits set forth in the final permit at all times. In the event of excess emissions, AECI is required to report to MDNR's Air Pollution Control Program in accordance with 10 CSR 10-6.050.

Comment (excerpts): What is necessary to know is the following: What is each criteria pollutant concentration at the boundary of the site, a mile from the site, at nearby towns, five miles, 20 miles, etc., at the various typical weather conditions; local deposition. What is the concentration of these criteria pollutants at their deposition area and where is the deposition location for each?

> **MDNR Response:** This facility demonstrated compliance with the National Ambient Air Quality Standards (NAAQS) and increment standards via modeling. A modeling analysis on Class I areas as well as an Additional Impact Analysis was conducted to address potential impacts. Please see MDNR's Response to Washington University Comment VIII and the Modeling Memorandum attached to the final permit for further discussion.

Comments from Alex Elson on behalf of the Interdisciplinary Environmental Clinic at Washington University:

Comment (excerpts): I will focus now on fine particulate matters, also known as PM2.5. In 1997, the U.S. EPA established a National Ambient Air Quality Standard, or NAAQS, for fine particulate matter. Missouri DNR then included PM2.5 in its own list of ambient air quality standards. Under both Missouri and Federal law, DNR must meet two important requirements for all NAAQS pollutants before it can issue an air pollution construction permit.

First, DNR must ensure that projected PM2.5 emissions from the plant would not cause a violation of the PM2.5 standard in this region or downwind.

Second, DNR must set limits for PM2.5 emissions from the plant based on the best available control technology, or BACT."

"If DNR proceeds to issue a final permit for the proposed Norborne plant, it must first conduct modeling and ensure that the plant's PM2.5 emissions will not violate air quality standards. It must also conduct and set BACT-based limits on PM2.5 emissions from the proposed plant."

MDNR Response: Please see MDNR's Responses to Washington University's written Comment V.

<u>Comments from Ania Truszczynski on behalf of the Interdisciplinary Environmental Clinic at Washington University:</u>

Comment (excerpts): "In the draft permit DNR exempts emissions during start-up and shutdown from counting toward most of the emission limits for those pollutants. This violates the legal requirement that emission limits apply on a continuous basis. Moreover, because emissions are typically much higher during start-up and shutdown than during normal operations, this exemption gives AECI a free pass to emit excessive amounts of harmful pollutants for considerable periods of time.

The Sierra Club was surprised to see these exemptions in the draft AECI permit, because in the construction permit that DNR issued last year for Kansas City Power and Light's proposed Iatan II facility it included start-up and shutdown in all of the permit limits. DNR should do the same here."

MDNR Response: Please see MDNR's Responses to Washington University's written Comment IX.A.

Comment (excerpts): "Next I will discuss nitrogen oxide limits. The draft AECI permit sets emission limits in other coal-fired power plants' permits and are higher than the limits achieved by other power plants in their operations.

For example, the TS Power Newmont facility in Nevada has a limit and the Desert Rock facility in New Mexico have limits that are lower than the limits in AECI's draft permit. In addition, the limits in those other permits apply to shorter periods of time, which makes them much stricter."

MDNR Response: Please see MDNR's Responses to Washington University's written Comment X.B.

Comment (excerpts): "Now I'll turn to sulfur dioxide limits. The draft permit also has higher sulfur dioxide limits than the limits in other coal plants' permits and higher than the emissions actually achieved by other plants in their operations.

For example, the proposed Longleaf plant in Georgia has limits for sulfur dioxide. Because the Longleaf limits include emissions during start-up and shutdown, they are considerably lower than the proposed AECI limits."

MDNR Response: Please see MDNR's Responses to Washington University's written Comment X.C.

Comment (excerpts): "One clear problem with the AECI permit limits for PM10 is that they are considerably higher than the actual PM_{10} emissions being achieved at another plant right nearby, KCPL's Hawthorn Unit 5.

MDNR Response: Please see MDNR's Responses to Washington University's written Comment X.E.

<u>Comments from Noelle Matthews (excerpts)</u>: "When Associated Electric Cooperative began this mess, the power plant was a 600 megawatt power plant, then it grew to a 660 megawatt, but now it's grown, according to this permit, to a 780 megawatt gross output. What's it going to be next week, AECI? A thousand megawatts? Fifteen-hundred?

If this power plant does grow beyond the 780 megawatts, will these exact standards still apply? Or will DNR allow AECI a couple extra thousand tons of harmful emissions per year?

> **MDNR Response**: Per Special Condition 1.A, the heat input to the main boiler shall not exceed 6,872 British Thermal Units per hour (MMBtu/hr). This is equivalent to a maximum net electrical output of 689 Megawatts (MW) or 780 MW gross output. Therefore, AECI will not have the authority to increase their electrical output above the stated amounts.

Comment (excerpts): "Is this power plant going to burn discarded tires at a later date, too? Where are the standards in this permit that will keep tires from being burned like the millions that are burned at the Sibley plant just up river from here."

> **MDNR Response**: AECI does not have the authority to burn discarded tires at this time. As stated in Special Condition 1.C of the permit, AECI shall use no other fuels other than low sulfur, subbituminous coal and No.2 fuel oil without receiving prior written authorization from the Air Pollution Control Program. If AECI were to request the burning of discarded tires in their main boiler, a complete analysis of potential emission increases must first be submitted and the appropriate permitting actions in accordance with state and federal regulations completed before permission is granted.

<u>Comments from Karen Saadeh:</u>

Comment (excerpts): "First, I have a question. If the overall efficiency of the baghouses on the railcar coal unloading building is 84.2 percent, then I assume that the surrounding communities get to breathe the other 15.8 percent of the dust generated by the dumper; am I correct?

As the coal is moved from the unloading building to the main boiler -- much of the time in open areas using at least five conveyor belts, telescoping chutes and bulldozers -- there appear to be no other dust controls or monitoring.

The application states that there will be a residual binder on the coal, and water spray will aid in reducing emissions. How much? Is it a requirement? Who will monitor it?

There will be nearly 12 acres of exposed coal piles. How will we be protected from dust blowing off these piles?

> MDNR Response: MDNR has included the potential PM_{10} emissions ("dust") for all sources that are capable of producing PM_{10}. As a part of the PSD process, AECI is required to put on the Best Available Control Technology (BACT) to minimize emissions. BACT for the main boiler for filterable PM_{10}/PM is use of a fabric filtration system. BACT for other PM_{10} sources include pavement and periodic washing of haul roads, application of chemical surfactant or documented watering for the landfill haul road and storage piles, combination of spray dust suppression, enclosures, and baghouses for the material handling transfer points. Please see the Installation/Project Description and Emission/Controls Evaluation sections of the permit for a complete description of maximum hourly design rates, emission factors sources, and required controls.
>
> In addition to installing BACT for all PM_{10} emission sources, AECI was required to submit a modeling analysis to show compliance with National Ambient Air Quality Standards (NAAQS) and PSD increment. Please see the Modeling Memorandum attached to the final permit for more information.

Corrections/Clarifications to the Draft Permit

The Air Pollution Control Program has made the following corrections and clarifications to the draft permit based on suggestions from Associated Electric Cooperative Inc. (AECI). MDNR has included the emails here for the record.

Email received 10/15/2007 from Todd Tolbert of AECI to Susan Heckenkamp: Referencing the "Potential Emissions of the Application" column for NO_x, the value ("2,155.26') appears to be a typo error. The TPY [ton per year] for the main boiler is calculated as (0.05 lb/MMBTU) x (6,872 MMBtu) x (8,760 hr/year) / (2,000 lbs/ton) = 1,505 tpy.

> **MDNR Response:** 2,155.26 tpy was based on 0.07 lb/MMBtu which is the 30-day rolling average limit for NO_x. However, AECI will not be allowed to exceed 0.05 lb/MMBtu on 12-month rolling average. Therefore, MDNR will change Table 3 of the permit to reflect an annual NO_x emission rate of 1,505 tpy.

Email received 2/14/2008 from Brent Ross of AECI to Susan Heckenkamp: We would like to add some minor language to the Norborne air permit to clarify the special conditions. These changes don't change the permit conditions but clarify the language so we don't have confusion for compliance. Below is a list of suggestions for the main boiler:

- 1.A The phrase "(less than 0.62 pound per million ....)" should specify as sulfur or as SO2. For example (less than 0.62 pound SO2 per million ....).(Page 2)

  MDNR's Response: The maximum sulfur content of the coal is 0.5% which equates to 0.62 lb sulfur per MMBtu. MDNR will change Special Condition 1.A accordingly.

- 1.D- Change "activate carbon" to "activate carbon or sorbent" to allow flexibility (short-term and long term) to use improved sorbents and changes in technology. (Page 2)
- 1.F (2) a-c)- insert "weight" in front of "percent". (Page 3)
- 1.G.(3-5) add after lb/hr , "test method average". (Page 4)

  MDNR's Response: MDNR agrees the suggested changes for Special Condition 1.D, 1.F, and 1.G are appropriated and have updated the final permit to reflect these changes.

Attachment A: W.A. Parish Units 5, 6, 7 & 8 Performance Data