Oklahoma Department of Environmental Quality
Air Quality Division

BART Application Analysis **January 19, 2010**

COMPANY:	**AEP-Public Service Company of Oklahoma**
FACILITY:	**Northeastern Power Plant**
FACILITY LOCATION:	**Rogers County, Oklahoma**
TYPE OF OPERATION:	**(1) 495 MW Natural Gas-Fired Steam Electric Generating Unit** **(2) 490 MW Coal-Fired Steam Electric Generating Units**
REVIEWERS:	**Phillip Fielder, Senior Engineering Manager** **Lee Warden, Engineering Manager**

I. PURPOSE OF APPLICATION

On July 6, 2005, the U.S. Environmental Protection Agency (EPA) published the final "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations" (the "Regional Haze Rule" 70 FR 39104). The Regional Haze Rule requires certain States, including Oklahoma, to develop programs to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in Class I Areas. The Regional Haze Rule requires states to submit a plan to implement the regional haze requirements (the Regional Haze SIP). The Regional Haze SIP must provide for a Best Available Retrofit Technology (BART) analysis of any existing stationary facility that might cause or contribute to impairment of visibility in a Class I Area.

II. BART ELIGIBILITY DETERMINATION

BART-eligible sources include those sources that:

(1) have the potential to emit 250 tons or more of a visibility-impairing air pollutant;
(2) were in existence on August 7, 1977 but not in operation prior to August 7, 1962; and
(3) whose operations fall within one or more of the specifically listed source categories in 40 CFR 51.301 (including fossil-fuel fired steam electric plants of more than 250 mmBtu/hr heat input and fossil-fuel boilers of more than 250 mmBtu/hr heat input).

Northeast Units 2, 3 and 4 are fossil-fuel fired boilers with heat inputs greater than 250-mmBtu/hr. All three units were in existence prior to August 7, 1977, but not in operation prior to August 7, 1962. Based on a review of existing emissions data, the units have the potential to emit more than 250 tons per year of NO_X, SO_2, and PM_{10}, visibility impairing pollutants. Therefore, Northeast Units 2, 3 and 4 meet the definition of BART-eligible sources.

BART is required for any BART-eligible source that emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I Area. DEQ has determined that an individual source will be considered to "contribute to visibility impairment" if emissions from the source result in a change in visibility, measured as a change in deciviews (Δ-dv), that is greater than or equal to 0.5 dv in a Class I area. Visibility impact modeling conducted by AEP-PSO determined that the maximum predicted visibility impacts from Northeast Units 2, 3 and 4 exceeded the 0.5 Δ-dv threshold at the Wichita Mountains, Caney Creek, Upper Buffalo, and Hercules Glade Class I Areas. Therefore, Northeast Units 2, 3 and 4 were determined to be BART applicable sources, subject to the BART determination requirements.

III. DESCRIPTION OF BART SOURCES

Baseline emissions from Northeastern Units 2, 3 and 4 were developed based on an evaluation of actual emissions data submitted by the facility pursuant to the federal Acid Rain Program. In accordance with EPA guidelines in 40 CFR 51 Appendix Y Part III, emission estimates used in the modeling analysis to determine visibility impairment impacts should reflect steady-state operating conditions during periods of high capacity utilization. Therefore, modeled emissions (lb/hr) represent the highest 24-hour block emissions reported during the baseline period. Baseline emission rates (lb/mmBtu) were calculated by dividing the average annual mass emission rates for each boiler by the boiler's average heat input over the years 2004 through 2006.

Table 1: Northeastern Power Plant- Plant Operating Parameters for BART Evaluation

Parameter	Northeastern Unit 2		Northeastern Unit 3		Northeastern Unit 4	
Plant Configuration	Natural Gas-Fired Boiler		Coal-Fired Boiler		Coal-Fired Boiler	
Firing Configuration			Tangentially-fired		Tangentially-fired	
Gross Output (nominal)	495 MW		490 MW		490 MW	
Maximum Input to Boiler	4,754 mmBtu/hr		4,775 mmBtu/hr		4,775 mmBtu/hr	
Maximum 24-hour Average Input	4,767 mmBtu/hr		5,812 mmBtu/hr		5,594 mmBtu/hr	
Primary Fuel	Natural Gas		Sub-bituminous coal		Sub-bituminous coal	
Existing NO_X Controls	1st Generation LNB/OFA		1st Generation LNB/OFA		1st Generation LNB/OFA	
Existing PM_{10} Controls	NA		Electrostatic precipitator		Electrostatic precipitator	
Existing SO_2 Controls	NA		Low-sulfur coal		Low-sulfur coal	
Maximum 24-hour Emissions (CALPUFF Model)						
	Unit 2		**Unit 3**		**Unit 4**	
	lb/hr	**lb/mmBtu**	**lb/hr**	**lb/mmBtu**	**lb/hr**	**lb/mmBtu**

NO_X	3,385	0.71	3,116	0.536	2,747	0.491
SO_2	2.9	0.0006	6,106	1.05	5,930	1.06
PM_{10}	35.4	0.007	220	0.038	330	0.059
Baseline Emissions (2004- 2006)						
	lb/hr	**lb/mmBtu**	**lb/hr**	**lb/mmBtu**	**lb/hr**	**lb/mmBtu**
NO_X	1462	0.449	1838	0.397	1827	0.404
SO_2	1.66	0.0006	4235	0.914	4102	0.907

IV. BEST AVAILABLE RETROFIT TECHNOLOGY (BART)

Guidelines for making BART determinations are included in Appendix Y of 40 CFR Part 51 (Guidelines for BART Determinations under the Regional Haze Rule). States are required to use the Appendix Y guidelines to make BART determinations for fossil-fuel-fired generating plants having a total generating capacity in excess of 750 MW. The BART determination process described in Appendix Y includes the following steps:

Step 1. Identify All Available Retrofit Control Technologies.
Step 2. Eliminate Technically Infeasible Options.
Step 3. Evaluate Control Effectiveness of Remaining Control Technologies.
Step 4. Evaluate Impacts and Document the Results.
Step 5. Evaluate Visibility Impacts.

In the final Regional Haze Rule U.S.EPA established presumptive BART emission limits for SO_2 and NO_X for certain electric generating units (EGUs) based on fuel type, unit size, cost effectiveness, and the presence or absence of pre-existing controls. The presumptive limits apply to EGUs at power plants with a total generating capacity in excess of 750 MW. For these sources, EPA established presumptive emission limits for coal-fired EGUs greater than 200 MW in size. The presumptive levels are intended to reflect highly cost-effective technologies as well as provide enough flexibility to States to consider source specific characteristics when evaluating BART. The BART SO_2 presumptive emission limit for coal-fired EGUs greater than 200 MW in size without existing SO_2 control is either 95% SO_2 removal, or an emission rate of 0.15 lb/mmBtu, unless a State determines that an alternative control level is justified based on a careful consideration of the statutory factors. For NO_X, EPA established a set of BART presumptive emission limits for coal-fired EGUs greater than 200 MW in size based upon boiler size and coal type. The BART NO_X presumptive emission limit applicable to Northeast Units 3 and 4 (tangentially fired boilers firing subbituminous coal) is 0.15 lb/mmBtu.

Table 2: BART Controls and Limits

Unit	NO_X BART Emission Limit	BART Technology
Northeastern Unit 2	0.28 lb/mmBtu (30-day average)	Combustion controls including LNB/OFA
Northeastern Unit 3	0.15 lb/mmBtu (30-day average)	Combustion controls including LNB/OFA
Northeastern Unit 4	0.15 lb/mmBtu (30-day average)	Combustion controls including LNB/OFA
Unit	**SO_2 BART Emission Limit**	**BART Technology**
Northeastern Unit 3	0.65 lb/mmBtu (30-day average)	Low Sulfur Coal
Northeastern Unit 4	0.65 lb/mmBtu (30-day average)	Low Sulfur Coal
Unit	**PM_{10} BART Emission Limit**	**BART Technology**
Northeastern Unit 3	0.1 lb/mmBtu (3-hour average)[1]	Existing ESP

Northeastern Unit 4	0.1 lb/mmBtu (3-hour average)[1]	Existing ESP

[1]Current emissions limits for ESPs are based on minimum NSPS requirements for front half catch. As part of the permitting process, PSO will be required to propose emission limits for front and back half reflective of the control technology and consistent with performance test results.

A. NO_X

IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES

Potentially available control options were identified based on a comprehensive review of available information. NO_X control technologies with potential application to Northeast Units 2, 3 and 4 are listed in Table 3.

Table 3: List of Potential Control Options

Control Technology
Combustion Controls
Burners Out of Service (NE 2 only)
Flue Gas Recirculation (FGR)
Low NO_X Burners and Overfire Air (LNB/OFA)
Post Combustion Controls
Selective Noncatalytic Reduction (SNCR)
Selective Catalytic Reduction (SCR)
Reburning /Methane de-NO_X (MdN)

ELIMINATE TECHICALLY INFEASIBLE OPTIONS (NO_X)

Combustion Controls:

Burners Out of Service

This option involves shutting off selected burners, resulting in reduced fuel usage and therefore lower emissions. This option would essentially reduce the maximum firing rate of the boiler, and place a load limit on the unit. The resulting load limits would effectively result in the shutdown of the unit and as a result, this option is considered technically infeasible.

Flue Gas Recirculation

Flue gas recirculation (FGR) controls NO_X by recycling a portion of the flue gas back into the primary combustion zone. The recycled air lowers NO_X emissions by two mechanisms: (1) the recycled gas, consisting of products which are inert during combustion, lowers the combustion temperatures; and (2) the recycled gas will reduce the oxygen content in the primary flame zone. The amount of recirculation is based on flame stability.

FGR control systems have been used as a retrofit NO_X control strategy on natural gas-fired boilers, but have not generally been considered as a retrofit control technology on coal-fired units. Natural gas-fired units tend to have lower O_2 concentrations in the flue gas and low particulate loading. In a coal-fired application, the FGR system would have to handle hot particulate-laden flue gas with a relatively high O_2 concentration. Although FGR has been used on coal-fired boilers for flue gas temperature control, it would not have application on a coal-fired boiler for NO_X control. Because of the flue gas characteristics (e.g., particulate loading and O_2 concentration), FGR would not operate effectively as a NO_X control system on a coal-fired boiler. Therefore, FGR is not considered an applicable retrofit NO_X control option for Northeast Units 3 and 4, and will not be considered further in the BART determination.

For Unit 2, Induced Flue Gas Recirculation (IFGR) would also place load limits on the boiler and call for plant equipment upgrades. As with the Burners Out of Service option, IFGR is considered technically infeasible.

Low NO_X Burners (LNB)/ Over Fire Air (OFA)

Low NO_X burners (LNB) limit NO_X formation by controlling both the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. Over Fire Air (OFA) allows for staged combustion. Staging combustion reduces NO_X formation with a cooler flame in the initial stage and less oxygen in the second stage.

LNB/OFA emission control systems have been installed as retrofit control technologies on existing coal-fired boilers. Northeast Units 3 and 4 operate as base load units. While technically feasible, LNB/OFA may not be as effective under all boiler operating conditions, especially during load changes and at low operating loads. Based on information available from burner control vendors and engineering judgment, it is expected that LNB/OFA on tangentially-fired boilers can be designed to meet the presumptive NO_X BART emission rate of 0.15 lb/mmBtu on a 30-day rolling average and under all normal operating conditions while maintaining acceptable CO and VOC emission rates.

For the natural gas-fired Unit 2, OFA as a single NO_X control technique may reduce NO_X emissions by 25-55 percent. When combined with LNB, reductions of up to 60% may result. This technology is a feasible option for all three units.

Reburning/Methane De-NO_X

In reburning, also known as “off-stoichiometric combustion” or “fuel staging,” a fraction (5 to 25 percent) of the total fuel heat input is diverted to a second combustion zone downstream of the primary zone. The fuel in the fuel-rich secondary zone acts as a reducing agent, reducing NO, which is formed in the primary zone, to N_2. Generally, it is more economical for a facility to use the same fuel for reburning as it does for primary combustion, although there are exceptions. In order to use coal as a reburning fuel, it must be finely ground, which requires additional pulverizing equipment.

Methane de- NO_X (MdN) utilizes the injection of natural gas together with recirculated flue gases (for enhanced mixing) to create an oxygen-rich zone above the combustion grate. OFA is then injected at a higher furnace elevation to burn out the combustibles. This process is claimed to yield between 50 and 70 percent NO_X reduction and to be suitable for all solid fuel-fired stoker boilers. However, as of 2002, MdN had only been demonstrated for a short duration in one pulp mill wood-fired stoker boiler that also burned small amounts of waste treatment plant residuals, with NO_X reductions of 40 to 50 percent reported.

MdN is not considered feasible for the coal-fired units because (1) it is not fully demonstrated and (2) it incorporates FGR, which is technically infeasible for all three units.

Post Combustion Controls:

Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia or urea at high flue gas temperatures. The ammonia or urea reacts with NO_X in the flue gas to produce N_2 and water. At temperatures below the desired operating range, the NO_X reduction reactions diminish and NH_3 emissions increase. Above the desired temperature range, NH_3 is oxidized to NO_X resulting in low NO_X reduction efficiencies. Mixing of the reactant and flue gas within the reaction zone is also an important factor in SNCR performance. In large boilers, the physical distance over which the reagent must be dispersed increases, and the surface area/volume ratio of the convective pass decreases. Both of these factors make it difficult to achieve good mixing of reagent and flue gas, reducing overall efficiency. Performance is further influenced by residence time, reagent-to-NO_X ratio, and fuel sulfur content.

The size of the Northeastern Units would represent several design problems making it difficult to ensure that the reagent would be injected at the optimum flue gas temperature, and that there would be adequate mixing and residence time. The physical size of the Northeastern boilers makes it technically infeasible to locate and install ammonia injection points capable of achieving adequate mixing within the required temperature zone. Higher reagent injection rates would be required to achieve adequate mixing. Higher ammonia injection rates would result in relatively high levels of ammonia in the flue gas (ammonia slip), which could lead to plugging of downstream equipment.

Another design factor limiting the applicability of SNCR control systems on large subbituminous coal-fired boilers is related to the reflective nature of subbituminous ash. Subbituminous coals typically contain high levels of calcium oxide and magnesium oxide that can result in reflective ash deposits on the waterwall surfaces. Because most heat transfer in the furnace is radiant, reflective ash can result in less heat removal from the furnace and higher exit gas temperatures. If ammonia is injected above the appropriate temperature window, it can actually lead to additional NO_X formation.

Installation of SNCR on large boilers, such as those at Northeastern, has not been demonstrated in practice. Assuming that SNCR could be installed on the Northeastern Units, given the issues addressed above, control effectiveness would be marginal, and depending on boiler exit temperatures, could actually result in additional NO_X formation.

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) involves injecting ammonia into boiler flue gas in the presence of a catalyst to reduce NO_X to N_2 and water. Anhydrous ammonia injection systems may be used, or ammonia may be generated on-site from a urea feedstock.

SCR has been installed as NO_X control technology on existing coal-fired boilers. Based on emissions data available from the EPA Electronic Reporting website, large coal-fired boilers have achieved actual long-term average NO_X emission rates in the range of approximately 0.04 to 0.1 lb/mmBtu. Several design and operating variables will influence the performance of the SCR system, including the volume, age and surface area of the catalyst (e.g., catalyst layers), uncontrolled NO_X emission rate, flue gas temperature, and catalyst activity.

Based on emission rates achieved in practice at existing subbituminous coal-fired units, and taking into consideration long-term operation of an SCR control system (including catalyst plugging and deactivation) it is anticipated that SCR could achieve a controlled NO_X emission rate of 0.054 lb/mmBtu on Northeast Unit 3 and 0.049 lb/mmBtu on Unit 4. The addition of SCR controls to Unit 2 could result in a controlled NO_X emission rate of 0.05 lb/mmBtu.

EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES (NO_X)

Table 4: Technically Feasible NO_X Control Technologies- Northeastern Power Plant

	Northeastern Unit 2	Northeastern Unit 3	Northeastern Unit 4
Control Technology	Approximate NO_X Emission Rate (lb/mmBtu)	Approximate NO_X Emission Rate (lb/mmBtu)	Approximate NO_X Emission Rate (lb/mmBtu)
LNB/OFA + SCR	0.05	0.054	0.049
LNB/OFA	0.28	0.15	0.15
SNCR	--	0.402	0.368
Baseline	0.449	0.397	0.404

EVALUATE IMPACTS AND DOCUMENT RESULTS (NO_X)

AEP-PSO evaluated the economic, environmental, and energy impacts associated with the proposed control options. In general, the cost estimating methodology followed guidance provided in the EPA Air Pollution Cost Control Manual. Capital costs were developed by AEP-PSO and are based on equipment costs for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit Northeast Units 2, 3 and 4 with the control technologies. Fixed and variable O&M costs were developed for each control system. Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent (e.g., ammonia) and auxiliary power requirements. Auxiliary power requirements reflect the additional power requirements associated with operation of the new control technology, including operation of any new fans as well as the power requirements for pumps, reagent handling, and by-product handling. The capital recovery factor used to estimate the annual cost of control was based on an 8% interest rate and a control life of 20 years. Annual operating costs and annual emission reductions were calculated assuming a capacity factor of 21% for Unit 2 and a capacity factor of 85% for SO_2 control effectiveness calculations for Units 3 and 4. No capacity factors were used for NO_X control effectiveness calculations.

AEP-PSO submitted initial cost estimates in 2008 that relied upon a baseline emission rate representative of the maximum actual 24-hour emission rate, which is consistent with the modeling demonstration. However, the calculations overestimate the cost effectiveness by assuming a larger ton per year emissions reduction with the addition of controls than would be realized given actual annual average emissions. Using a representative annual average emission rate (2004-2006), the cost effectiveness ($/ton removed) is much higher, but the result is representative of more reasonably achievable emissions reductions.

Table 5: Economic Cost for Units 3 and 4 (Coal-Fired Boilers)

Cost	Option 1: SNCR[2]	Option 2: LNB/OFA	Option 3: LNB/OFA +SCR[1]
Total Capital Investment ($)	$11,500,000	$17,000,000	$290,000,000
Annualized Capital Cost ($/Yr)	$1,171,300	$1,731,488	$29,537,141
Annual O&M Costs ($/Yr)	$13,602,120	$680,000	$18,248,660
Annual Cost of Control ($)	$14,773,420	$2,411,488	$47,785,801

[1]While not stated explicitly, costs for SCR are assumed to encompass LNB/OFA as well.
[2]Costs associated with SNCR are greater than LNB/OFA with less potential reduction in emissions, no further review will be required.

Table 6: Environmental Costs for Units 3 and 4 (Coal-Fired Boiler)

	Baseline	LNB/OFA	LNB/OFA +SCR
NO_X Emission Rate (lb/mmBtu) Unit3	0.397	0.15	0.054
NO_X Emission Rate (lb/mmBtu) Unit4	0.404	0.15	0.049
Annual NO_X Emission (TPY)[1]	13,971	6,274	2,154
Annual NO_X Reduction (TPY)	--	7,697	11,817
Annual Cost of Control	--	$2,411,488	$47,785,801
Cost per Ton of Reduction	--	$313	$4,044
Incremental Cost per ton of Reduction[2]	--		$11,013

(1) Emissions for the BART analysis are based on annual average emissions from 2004-2006 for Units 3 & 4.
(2) Incremental cost effectiveness of the SCR system is compared to costs/emissions associated with LNB/OFA controls.

Table 7: Economic Cost for Unit 2 (Natural Gas-Fired Boilers)

Cost	Option 1: LNB/OFA	Option 2: LNB/OFA +SCR[1]
Total Capital Investment ($)	$3,450,000	$94,743,000
Annualized Capital Cost ($/Yr)	$351,390	$9,649,784
Annual O&M Costs ($/Yr)	$138,000	$3,789,720
Annual Cost of Control ($)	$489,390	$14,366,357

[1]While not stated explicitly, costs for SCR are not assumed to encompass LNB/OFA based on the incremental cost analysis completed by the applicant.

Table 8: Environmental Costs for Unit 2 (Natural Gas-Fired Boiler)

	Baseline	Option 2: LNB/OFA	Option 3: LNB/OFA +SCR
NO_X Emission Rate (lb/mmBtu) Unit2	0.449	0.285	0.05
Annual NO_X Emission (TPY)[1]	2,861	1,246	219
Annual NO_X Reduction (TPY)	--	1615	2642
Annual Cost of Control		$489,390	$14,366,357
Cost per Ton of Reduction		$303	$5,438
Incremental Cost per ton of Reduction[2]			$13,512

(1) Emissions for the BART analysis are based on annual average emission from 2005- 2006 (2004 emissions are not reflective of annual averages. Annual costs for LNB/OFA assumed a capacity factor of 0.21. The applicant used a capacity factor of 0.19 in the SCR evaluation; however, the analysis reported here reflects the 0.21 capacity factor documented in the original submittal.
(2) Incremental cost effectiveness of the SCR system is compared to costs/emissions associated with LNB/OFA controls.

B. SO_2

IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES (SO_2)

Potentially available control options were identified based on a comprehensive review of available information. SO_2 control technologies with potential application to Northeast Units 3 and 4 are listed in Table 9.

Table 9: List of Potential Control Options

Control Technology
Pre-Combustion Control
Wet Flue Gas Desulfurization
Dry Flue Gas Desulfurization-Spray Dryer Absorber

ELIMINATE TECHICALLY INFEASIBLE OPTIONS (SO_2)

Pre-Combustion Control Strategy:

Fuel Switching

One potential strategy for reducing SO_2 emissions is reducing the amount of sulfur contained in the coal. Northeast Units 3 and 4 fire subbituminous coal as their primary fuel. Subbituminous coal has a relatively low heating value, low sulfur content, and low uncontrolled SO_2 emission rate. No environmental benefits accrue from burning an alternative coal; however, subbituminous coal with lower sulfur content is achievable and available. Fuel switching to a lower sulfur content coal is a viable option.

Coal Washing

Coal washing, or beneficiation, is one pre-combustion method that has been used to reduce impurities in the coal such as ash and sulfur. In general, coal washing is accomplished by separating and removing inorganic impurities from organic coal particles. The coal washing process generates a solid waste stream consisting of inorganic materials separated from the coal, and a wastewater stream that must be treated prior to discharge. Solids generated from wastewater processing and coarse material removed in the washing process must be disposed in a properly permitted landfill. Solid wastes from coal washing typically contain pyrites and other dense inorganic impurities including silica and trace metals. The solids are typically dewatered in a mechanical dewatering device and disposed of in a landfill.

Northeast Units 3 and 4 are designed to utilize subbituminous coals. Based on a review of available information, no information was identified regarding the washability or effectiveness of washing subbituminous coals. Therefore, coal washing is not considered an available retrofit control option for Northeast Units 3 and 4.

Coal Processing

Pre-combustion coal processing techniques have been proposed as one strategy to reduce the sulfur content of coal and help reduce uncontrolled SO_2 emissions. Coal processing technologies are being developed to remove potential contaminants from the coal prior to use. These processes typically employ both mechanical and thermal means to increase the quality of subbituminous coal and lignite by removing moisture, sulfur, mercury, and heavy metals. To date, the use of processed fuels has only been demonstrated with test burns in a coal-fired boiler. No coal-fired boilers have utilized processed fuels as their primary fuel source on an on-going, long-term basis. Although burning processed fuels, or a blend of processed fuels, has been tested in a coal-fired boiler, using processed fuels in Northeast Units 3 and 4 would require significant research, test burns, and extended trials to identify potential impacts on plant systems, including the boiler, material handling, and emission control systems. Therefore, processed fuels are not considered commercially available, and will not be analyzed further in this BART analysis.

Post-Combustion Flue Gas Desulfurization:
Wet Scrubbing Systems
Wet FGD technology is an established SO_2 control technology. Wet scrubbing systems offered by vendors may vary in design; however, all wet scrubbing systems utilize an alkaline scrubber slurry to remove SO_2 from the flue gas.

Wet Lime Scrubbing
The wet lime scrubbing process uses an alkaline slurry made by adding lime (CaO) to water. The alkaline slurry is sprayed in the absorber and reacts with SO2 in the flue gas. Insoluble $CaSO_3$ and $CaSO_4$ salts are formed in the chemical reaction that occurs in the scrubber and are removed as a solid waste by-product. The waste by-product is made up of mainly $CaSO_3$, which is difficult to dewater. Solid waste by-products from wet lime scrubbing are typically managed in dewatering ponds and landfills.

Wet Limestone Scrubbing
Limestone scrubbers are very similar to lime scrubbers except limestone ($CaCO_3$) is mixed with water to formulate the alkali scrubber slurry. SO_2 in the flue gas reacts with the limestone slurry to form insoluble $CaSO_3$ and $CaSO_4$ which is removed as a solid waste by product. The use of limestone instead of lime requires different feed preparation equipment and a higher liquid-to-gas ratio. The higher liquid-to-gas ratio typically requires a larger absorbing unit. The limestone slurry process also requires a ball mill to crush the limestone feed.

Forced oxidation of the scrubber slurry can be used with either the lime or limestone wet FGD system to produce gypsum solids instead of the calcium sulfite by-product. Air blown into the reaction tank provides oxygen to convert most of the calcium sulfite ($CaSO_3$) to relatively pure gypsum (calcium sulfate). Forced oxidation of the scrubber slurry provides a more stable by-product and reduces the potential for scaling in the FGD. The gypsum by-product from this process must be dewatered, but may be salable thus reducing the quantity of solid waste that needs to be landfilled.

Wet lime and wet limestone scrubbing systems will achieve the same SO_2 control efficiencies; however, the higher cost of lime typically makes wet limestone scrubbing the more attractive option. For this reason, wet lime scrubbing will not be evaluated further in this BART determination.

Wet Magnesium Enhanced Lime Scrubbing

Magnesium Enhanced Lime (MEL) scrubbers are another variation of wet FGD technology. Magnesium enhanced lime typically contains 3% to 7% magnesium oxide (MgO) and 90 – 95% calcium oxide (CaO). The presence of magnesium effectively increases the dissolved alkalinity, and consequently makes SO_2 removal less dependent on the dissolution of the lime/limestone. MEL scrubbers have been installed on coal-fired utility boilers located in the Ohio River Valley. Systems to oxidize the MEL solids to produce a usable gypsum byproduct consisting of calcium sulfate (gypsum) and magnesium sulfate continue to be developed. Coal-fired units equipped with MEL FGD typically fire high-sulfur eastern bituminous coal and use locally available reagent. There are no subbituminous-fired units equipped with a MEL-FGD system. Because MEL-FGD systems have not been used on subbituminous-fired boilers, and because of the cost and limited availability of magnesium enhanced reagent (either naturally occurring or blended), and because limestone-based wet FGD control systems can be designed to achieve the same control efficiencies as the magnesium enhanced systems, MEL-FGD control systems will not be evaluated further as a commercially available retrofitted control system.

Jet Bubbling Reactor

Another variation of the wet FGD control system is the jet bubbling reactor (JBR). Unlike the spray tower wet FGD systems, where the scrubbing slurry contacts the flue gas in a countercurrent reaction tower, in the JBR-FGD flue gas is bubbled through a limestone slurry. Spargers are used to create turbulence within the reaction tank and maximize contact between the flue gas bubbles and scrubbing slurry. There is currently a limited number of commercially operating JBR-WFGD control systems installed on coal-fired utility units in the U.S. Although the commercial deployment of the control system continues, there is still a very limited number of operating units in the U.S. Furthermore, coal-fired boilers currently considering the JBR-WFGD control system are all located in the eastern U.S., and all fire eastern bituminous coals. The control system has not been proposed as a retrofit technology on any large subbituminous coal-fired boilers. However, other than scale-up issues, there do not appear to be any overriding technical issues that would exclude application of the control technology on a large subbituminous coal-fired unit. There are no data available to conclude that the JBR-WFGD control system will achieve a higher SO_2 removal efficiency than a more traditional spray tower WFGD design, especially on units firing low-sulfur subbituminous coal. Furthermore, the costs associated with JBR-WFGD and the control efficiencies achievable with JBR-WFGD are similar to the costs and control efficiencies achievable with spray tower WFGD control systems. Therefore, the JBR-WFGD will not be evaluated as a unique retrofit technology, but will be included in the overall assessment of WFGD controls.

Dual-Alkali Wet Scrubber

Dual-alkali scrubbing is a desulfurization process that uses a sodium-based alkali solution to remove SO_2 from combustion exhaust gas. The process uses both sodium-based and calcium-based compounds. The dual-alkali process requires lower liquid-to-gas ratios then scrubbing with lime or limestone. The reduced liquid-to-gas ratios generally mean smaller reaction units, however additional regeneration and sludge processing equipment is necessary. The sodium-based scrubbing liquor, typically consisting of a mixture of sodium hydroxide, sodium carbonate and sodium sulfite, is an efficient SO_2 control reagent. However, the high cost of the sodium-based chemicals limits the feasibility of such a unit on a large utility boiler. In addition, the process generates a less stable sludge that can create material handling and disposal problems. It is projected that a dual-alkali system could be designed to achieve SO_2 control similar to a limestone-based wet FGD. However, because of the limitations discussed above, and because dual-alkali systems are not currently commercially available, dual-alkali scrubbing systems will not be addressed further in this BART determination.

Wet FGD with Wet Electrostatic Precipitator

Wet electrostatic precipitation (WESP) has been proposed on other coal-fired projects as one technology to reduce sulfuric acid mist emissions from coal-fired boilers. WESPs have been proposed for boilers firing high-sulfur eastern bituminous coals controlled with wet FGD.24 WESP has not been widely used in utility applications, and has only been proposed on boilers firing high sulfur coals and equipped with SCR. Northeast Units 3 and 4 fire low-sulfur subbituminous coal. Based on the fuel characteristics, and assuming 1% SO_2 to SO_3 conversion in the boiler, potential uncontrolled H_2SO_4 emissions from Northeast Units 3 and 4 will only be approximately 5ppm. This emission rate does not take into account inherent acid gas removal associated with alkalinity in the subbiuminous coal fly ash. Based on engineering judgment, it is unlikely that a WESP control system would be needed to mitigate visible sulfuric acid mist emissions from Northeast Units 3 and 4, even if WFGD control was installed. WESPs have been proposed to control condensable particulate emissions from boilers firing a high-sulfur bituminous coal and equipped with SCR and wet FGD. This combination of coal and control equipment results in relatively high concentrations of sulfuric acid mist in the flue gas. WESP control systems have not been proposed on units firing subbituminous coals, and WESP would have no practical application on a subbituminous-fired units. Therefore, the combination of WFGD+WESP will not be evaluated further in this BART determination.

Dry Flue Gas Desulfurization

Another scrubbing system that has been designed to remove SO_2 from coal-fired combustion gases is dry scrubbing. Dry scrubbing involves the introduction of dry or hydrated lime slurry into a reaction tower where it reacts with SO_2 in the flue gas to form calcium sulfite solids Unlike wet FGD systems that produce a slurry byproduct that is collected separately from the fly ash, dry FGD systems produce a dry byproduct that must be removed with the fly ash in the particulate control equipment. Therefore, dry FGD systems must be located upstream of the particulate control device to remove the reaction products and excess reactant material.

Spray Dryer Absorber

Spray dryer absorber (SDA) systems have been used in large coal-fired utility applications. SDA systems have demonstrated the ability to effectively reduce uncontrolled SO_2 emissions from coal units. The typical spray dryer absorber uses a slurry of lime and water injected into the tower to remove SO_2 from the combustion gases. The towers must be designed to provide adequate contact and residence time between the exhaust gas and the slurry to produce a relatively dry by-product. SDA control systems are a technically feasible and commercially available retrofit technology for Northeast Units 3 and 4. Based on the fuel characteristics and allowing a reasonable margin to account for normal operating conditions (e.g., load changes, changes in fuel characteristics, reactant purity, atomizer change outs, and minor equipment upsets) it is concluded that dry FGD designed as SDA could achieve a controlled SO_2 emission rate of 0.15 lb/mmBtu (30-day average) on an on-going long-term basis.

Circulating Dry Scrubber

A third type of dry scrubbing system is the circulating dry scrubber (CDS). A CDS system uses a circulating fluidized bed of dry hydrated lime reagent to remove SO_2. The dry by-product produced by this system is similar to the spray dry absorber by-product, and is routed with the flue gas to the particulate removal system. Operating experience on smaller coal boilers in the U.S. has shown high lime consumption rates, and significant fluctuations in lime utilization based on inlet SO_2 loading. Furthermore, CDS systems result in high particulate loading to the unit's particulate control device. Based on the limited application of CDS dry scrubbing systems on large boilers, it is likely that AEP-PSO would be required to conduct extensive design engineering to scale up the technology for boilers the size of Northeast Units 3 and 4, and that AEP-PSO would incur significant time and resource penalties evaluating the technical feasibility and long-term effectiveness of the control system. Because of these limitations, CDS dry scrubbing systems are not currently commercially available as a retrofit control technology for Northeast Units 3 and 4, and will not be evaluated further in this BART determination.

EVALUATE EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES (SO_2)

Table 10: Technically Feasible SO_2 Control Technologies- Northeastern Station

	Northeastern Unit 3	Northeastern Unit 4
Control Technology	Approximate SO_2 Emission Rate (lb/mmBtu)	Approximate SO_2 Emission Rate (lb/mmBtu)
Wet FGD	0.063	0.063
Dry FGD- Spray Dryer Absorber	0.153	0.153
Lower Sulfur Coal	0.55	0.55
Baseline	0.9	0.9
Annual Average Baseline	0.91	0.91

EVALUATE IMPACTS AND DOCUMENT RESULTS (SO_2)

AEP-PSO evaluated the economic, environmental, and energy impacts associated with the two proposed control options. In general, the cost estimating methodology followed guidance provided in the EPA Air Pollution Cost Control Manual. Sixth Edition" EPA-452/B-02-001, January 2002. Cost estimates include the equipment, material, labor, and all other direct costs needed to retrofit Northeast Units 3 and 4 with the control technologies.

Direct O&M costs are those costs that tend to be proportional to the quantity of exhaust gas processed by the control system. These may include costs for catalysts, utilities (steam, electricity, and water), waste treatment and disposal, maintenance materials, replacement parts, and operating and maintenance labor. Of these direct O&M costs, costs for catalysts, utilities, waste treatment, and disposal are variable. Emission allowance costs associated with certain regulatory programs may also be represented as a variable O&M costs, but have not been included in this cost estimate. Indirect or "Fixed" annual costs are those whose values are totally independent of the exhaust flow rate and, in fact, would be incurred even if the control system were shut down. They include such categories as administrative charges, property taxes, and insurance, and include the capital recovery cost. The direct and indirect annual costs are offset by recovery credits, taken for materials or energy recovered by the control system, which may be sold, recycled to the process, or reused elsewhere at the site. The capital recovery factor used to estimate the annual cost of control was based on a 8% interest rate and a control life of 20 years. Annual operating costs and annual emission reductions were calculated assuming a capacity factor of 85%.

AEP-PSO submitted initial cost estimates in 2008 that relied upon a baseline emission rate representative of the average annual emission (0.9 lb/mmBtu) at an annual average firing rate of 4775 mmBtu/hr. The modeling demonstration relied on maximum 24-hr heat input numbers that were somewhat larger than the average. However the actual annual firing rate is much lower, and costs were reevaluated in order to be consistent with the methodology employed by EPA. Following the methodology published in the EPA advanced notice of proposed rulemaking for the Four Corners Power Plant and the Navajo Generating Station, cost effectiveness calculations were revised to reflect average annual emissions from 2004-2006.

The engineering estimates and possible vendor quotations AEP-PSO relied on to develop base $/kW Total Capital Investment assumptions were not provided to substantiate the capital costs for installation. In reviewing BART submittals to other states, AEP-PSO's estimated costs were found to be somewhat higher than those reported for similar projects. However, the evaluations in neighboring states are known to underestimate present day costs and the analysis submitted by AEP-PSO is in line with the more detailed and recent analyses submitted by OG&E.

Operation and maintenance cost estimates for AEP-PSO cost calculations rely on assumptions provided in the AEP-PSO submittal. While the assumptions for administrative costs were overstated, AEP-PSO failed to incorporate labor, maintenance, and increased water costs, which offset the overestimated numbers. Estimates are compared to operating costs documented in the June 2007 report by J. Edward Cichanowicz for the Utility Air Regulatory Group, "Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies. The Cichanowicz report reproduces a Sargent and Lundy graphic, which lists a cost range in $/kW of 15 to 38 for O&M costs. AEP-PSO estimates are approximately $33/kW. AEP-PSO's estimates are again comparable to the DEQ approved more recent and detailed cost estimates for OG&E.

Table 11: Economic Cost for Unit 3 and 4 - Dry FGD- Spray Dryer Absorber

Cost	DFGD/SDA
Total Capital Investment ($)	$546,700,000
Total Capital Investment ($/kW)	$582
Capital Recovery Cost ($/Yr)	$55,682,603
Annual O&M Costs ($/Yr)	$31,070,200
Total Annual Cost ($)	$86,752,803

Table 12: Environmental Costs for Unit 3 and 4

	Baseline	Lower S Coal	DFGD/SDA
SO_2 Emission Rate (lb/mmBtu)	0.91	0.55	0.153
Annual SO_2 Emission (TPY)[1]	31,779	19,555	5,440
Annual SO_2 Reduction (TPY)	--	12,224	26,339
Total Annual Cost ($)			$86,752,803
Cost per Ton of Reduction			$3,294

Incremental Cost per Ton			$6,146

[(1)] Baseline annual emissions were averaged based on annual emissions from 2004- 2006. Projected annual emissions were calculated based on the controlled SO_2 emissions rate, full load heat input of 4,775 mmBtu/hr, and assuming an 85% capacity factor.

Table 13: Environmental Costs for Units 3 and 4- Wet FGD

Cost	AEP-PSO Cost Estimates Units 3 and 4
Total Capital Investment ($)	$703,680,000
Total Capital Investment ($/kW)	$749
Capital Recovery Cost ($/Yr)	$71,671,362
Annual O&M Costs ($/Yr)	$35,419,400
Total Annual Cost ($)	$107,090,762
Baseline SO_2 Emission Rate (lb/mmBtu)	0.9
Control SO_2 Emission Rate (lb/mmBtu)	0.063
Baseline Annual Emissions (TPY)[1]	31,779
Controlled Annual SO_2 Emission (TPY)[1]	2,240
Annual SO_2 Reduction (TPY)	29,539
Cost per Ton of Reduction ($/Ton)	$3,625
Incremental Annual Cost ($/Ton)	$6,356

[(1)] Baseline annual emissions were calculated based on annual average emissions from 2004-2006.. Projected annual emissions were calculated based on the controlled SO_2 emissions rate, full load heat input of 4,775 mmBtu/hr, and assuming an 85% capacity factor.

C. PM_{10}

IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES (PM_{10})

There are two generally recognized PM control devices that are used to control PM emission from PC boilers: ESPs and fabric filters (or baghouses). Northeast Units 3 and 4 are currently equipped with ESP control systems.

Table 14: Summary of Technically Feasible Main Boiler PM_{10} Control Technologies

Control Technology	PM_{10} Emissions (lb/mmBtu)	% Reduction (from base case)
Fabric Filter Baghouse and ESP	0.0085/0.0079	99.9
ESP - Existing	0.025/0.040	99.7

EVALUATE IMPACTS AND DOCUMENT RESULTS (PM_{10})

Costs for Fabric Filter Baghouses were provided separate from the cost estimates provided by AEP-PSO for Dry FGD. While DEQ capital cost estimates rely on primarily fully loaded Wet FGD installations, the greater expense attributed to wet versus dry systems can account for the Fabric Filter Baghouse equipment cost without a direct line item cost.

For fabric filter baghouse controls AEP-PSO estimated a total capital investment of $71,050,000 for Units 3 and 4. The capital recovery cost was estimated to be $6,671,463 per year over 20 years at 7% interest. The total annual cost was estimated to be $12,773592. Addition of the fabric filters was anticipated to result in an incremental cost of $12,565/ton over existing ESP controls. The applicant did not evaluate replacement of the ESP but instead the addition of fabric filters.

D. VISIBILITY IMPROVEMENT DETERMINATION

The fifth of five factors that must be considered for a BART determination analysis, as required by a 40 CFR part 51- Appendix Y, is the degree of Class I area visibility improvement that would result from the installation of the various options for control technology. This factor was evaluated for the Northeastern Power Plant by using an EPA-approved dispersion modeling system (CALPUFF) to predict the change in Class I area visibility. The Division had previously determined that the Northeastern Power Plant was subject to BART based on the results of initial screening modeling that was conducted using current (baseline) emissions from the facility. The screening modeling, as well as more refined modeling conducted by the applicant, is described in detail below.

Wichita Mountain Wildlife Refuge, Caney Creek, Upper Buffalo and Hercules Glade are the closest Class I areas to the Northeastern Power Plant, as shown in Figure 1 below.

Only those Class I areas most likely to be impacted by the Northeastern Power Plant were modeled, as determined by source/Class I area locations, distances to each Class I area, and professional judgment considering meteorological and terrain factors. It can be reasonably assumed that areas at greater distances and in directions of less frequent plume transport will experience lower impacts than those predicted for the four modeled areas.

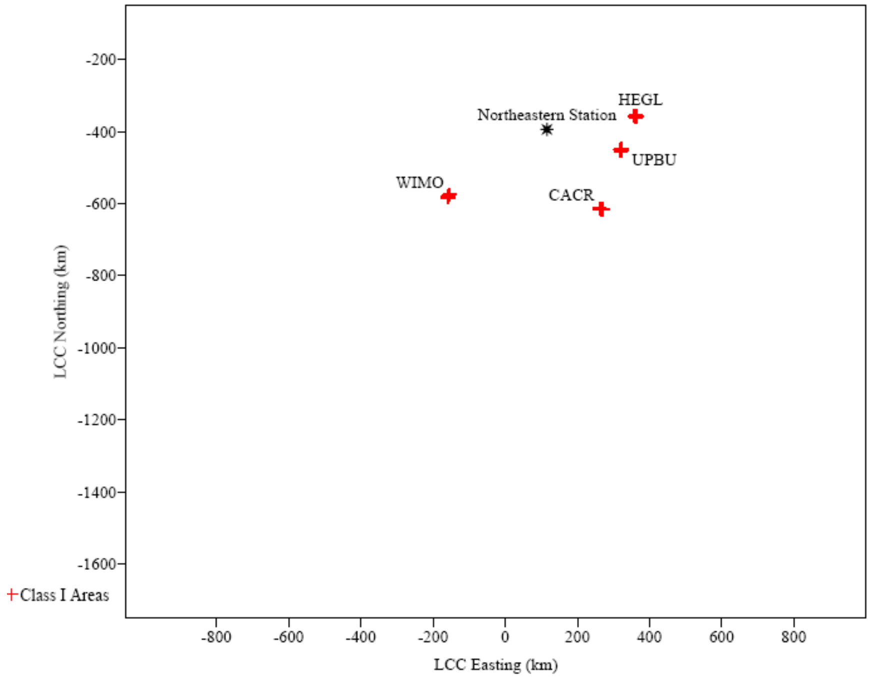

Figure 1: Plot of Facility location in relation to nearest Class I areas

REFINED MODELING

Because of the results of the applicants screening modeling for the Northeastern Power Plant, AEP-PSO was required to conduct a refined BART analysis that included CALPUFF visibility modeling for the facility. The modeling approach followed the requirements described in the Division's BART modeling protocol, CENRAP BART Modeling Guidelines (Alpine Geophysics, December 2005) with refinements detailed the applicants CALMET modeling protocol, CALMET Data Processing Protocol (Trinity Consultants, January 2008)

CALPUFF System

Predicted visibility impacts from the Northeastern Power Plant were determined with the EPA CALPUFF modeling system, which is the EPA-preferred modeling system for long-range transport. As described in the EPA Guideline on Air Quality Models (Appendix W of 40 CFR Part 51), long-range transport is defined as modeling with source-receptor distances greater than 50 km. Because all modeled areas are located more than 50 km from the sources in question, the CALPUFF system was appropriate to use.

The CALPUFF modeling system consists of a meteorological data pre-processor (CALMET), an air dispersion model (CALPUFF), and post-processor programs (POSTUTIL, CALSUM, CALPOST). The CALPUFF model was developed as a non-steady-state air quality modeling system for assessing the effects of time- and space-varying meteorological conditions on pollutant transport, transformation, and removal.

CALMET is a diagnostic wind model that develops hourly wind and temperature fields in a three-dimensional, gridded modeling domain. Meteorological inputs to CALMET can include surface and upper-air observations from multiple meteorological monitoring stations. Additionally, the CALMET model can utilize gridded analysis fields from various mesoscale models such as MM5 to better represent regional wind flows and complex terrain circulations. Associated two-dimensional fields such as mixing height, land use, and surface roughness are included in the input to the CALMET model. The CALMET model allows the user to "weight" various terrain influences parameters in the vertical and horizontal directions by defining the radius of influence for surface and upper-air stations.

CALPUFF is a multi-layer, Lagrangian puff dispersion model. CALPUFF can be driven by the three-dimensional wind fields developed by the CALMET model (refined mode), or by data from a single surface and upper-air station in a format consistent with the meteorological files used to drive steady-state dispersion models. All far-field modeling assessments described here were completed using the CALPUFF model in a refined mode.

CALPOST is a post-processing program that can read the CALPUFF output files, and calculate the impacts to visibility.

All of the refined CALPUFF modeling was conducted with the version of the CALPUFF system that was recognized as the EPA-approved release at the time of the application submittal. Version designations of the key programs are listed in the table below.

Table 15: Key Programs in CALPUFF System

Program	Version	Level
CALMET	5.53a	040716
CALPUFF	5.8	070623
CALPOST	5.6394	070622

Meteorological Data Processing (CALMET)

As required by the Division's modeling protocol, the CALMET model was used to construct the initial three-dimensional wind field using data from the MM5 model. Surface and upper-air data were also input to CALMET to adjust the initial wind field.

The following table lists the key user-defined CALMET settings that were selected.

Table 16: CALMET Variables

Variable	Description	Value
PMAP	Map projection	LCC (Lambert Conformal Conic)
DGRIDKM	Grid spacing (km)	4
NZ	Number of layers	12
ZFACE	Cell face heights (m)	0, 20, 40, 60, 80, 100, 150, 200, 250, 500, 1000, 2000, 3500
RMIN2	Minimum distance for extrapolation	-1
IPROG	Use gridded prognostic model outputs	14 km (MM5 data)
RMAX1	Maximum radius of influence	20 km

Variable	Description	Value
	(surface layer, km)	
RMAX2	Maximum radius of influence (layers aloft, km)	50 km
TERRAD	Radius of influence for terrain (km)	10 km
R1	Relative weighting of first guess wind field and observation (km)	10 km
R2	Relative weighting aloft (km)	25 km

The locations of the upper air stations with respect to the modeling domain are shown in Figure 2.

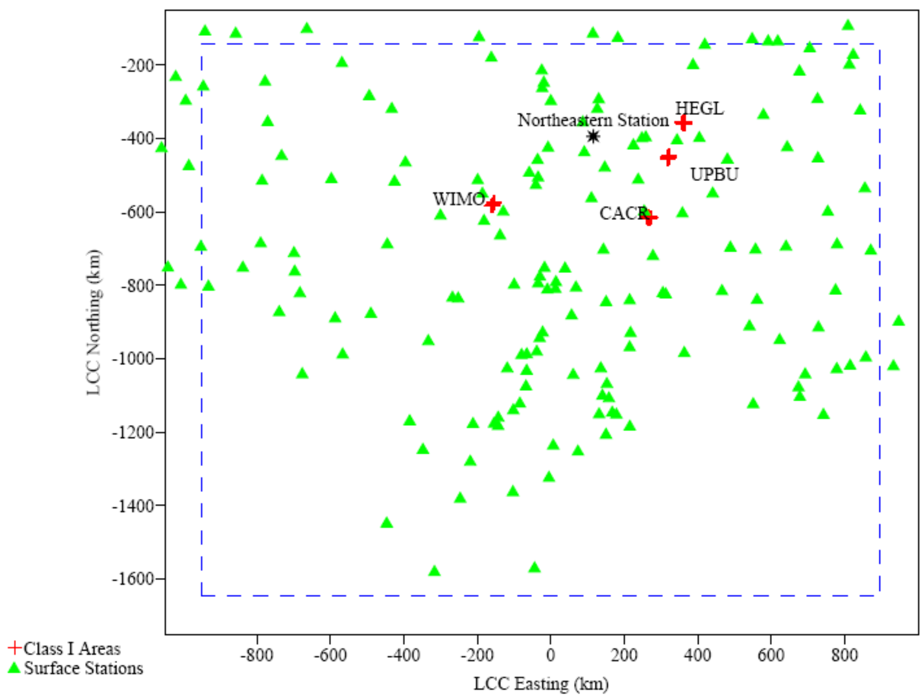

Figure 2: Plot of surface station locations

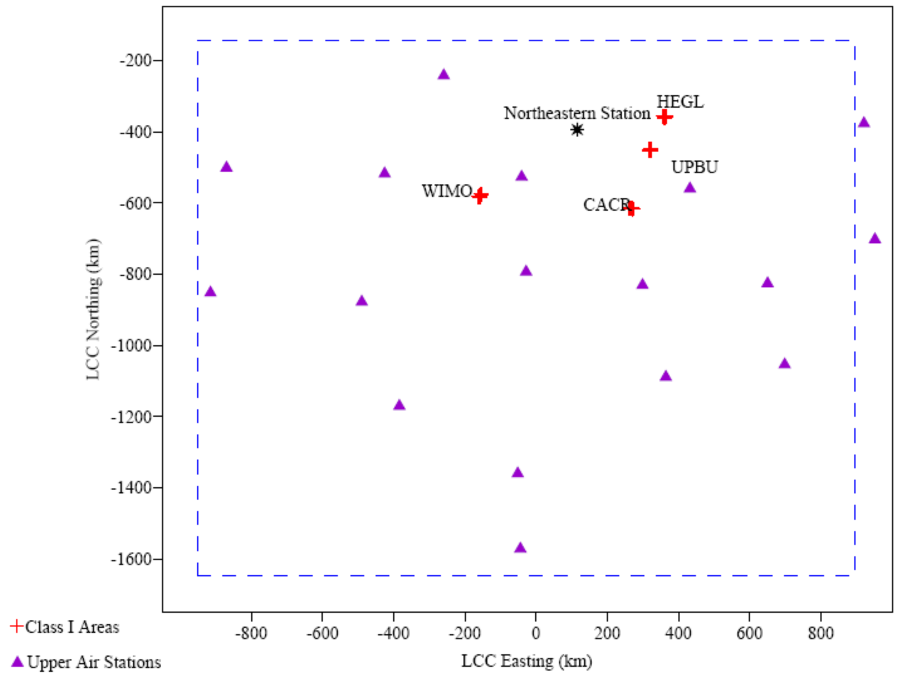

Figure 3: Plot of upper air station locations

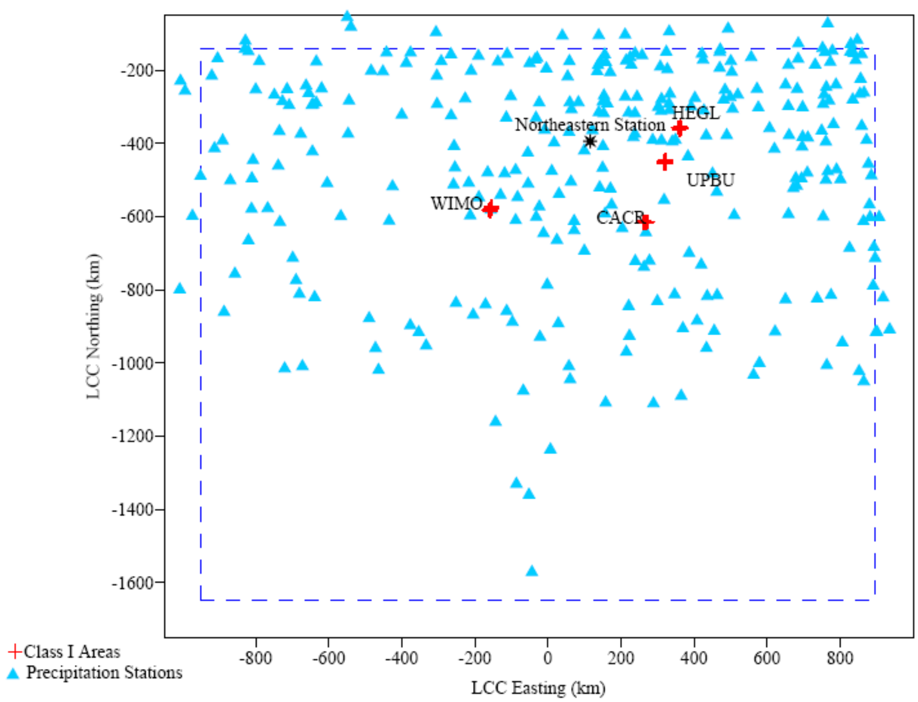

Figure 4. Plot of precipitation observation stations

CALPUFF Modeling Setup

To allow chemical transformations within CALPUFF using the recommended chemistry mechanism (MESOPUFF II), the model required input of background ozone and ammonia. CALPUFF can use either a single background value representative of an area or hourly ozone data from one or more ozone monitoring stations. Hourly ozone data files were used in the CALPUFF simulation. As provided by the Oklahoma DEQ, hourly ozone data from the Oklahoma City, Glenpool, and Lawton monitors over the 2001-2003 time frames were used. Background concentrations for ammonia were assumed to be temporally and spatially invariant and were set to 3 ppb.

Latitude and longitude coordinates for Class I area discrete receptors were taken from the National Park Service (NPS) Class I Receptors database and converted to the appropriate LCC coordinates.

CALPUFF Inputs- Baseline and Control Options

The first step in the refined modeling analysis was to perform visibility modeling for current (baseline) operations at the facility. Maximum 24-hour heat inputs and emission rates for the baseline emission calculations were established based on data from the years 2002 to 2005.

Baseline source release parameters and emissions are shown in the table below, followed by tables with data for the various control options. No attempt was made by the applicant to estimate the increase in sulfate emissions that would result from operations of SCR, and as a result the visibility improvement for those scenarios may be overestimated by some undetermined amount.

Table 17: Source Parameters

	Baseline[1]		
Parameter	Natural Gas-Fired Unit 2	Coal-Fired Unit 3	Coal-Fired Unit 4
Heat Input (mmBtu/hr)	4,767	5,812	5,594
Stack Height (m)	56	183	183
Stack Diameter (m)	5.49	8.23	8.23
Stack Temperature (K)[2]	394	424	415
Exit Velocity (m/s)[2]	16.29	18.97	17.46
Baseline SO_2 Emissions (lb/mmBtu)	0.0006	1.05	1.06
Dry FGD SO_2 Emissions (lb/mmBtu)	--	0.15	0.15
Wet FGD SO_2 Emissions (lb/mmBtu)	--	0.063	0.063
Baseline NO_X Emissions (lb/mmBtu)	0.71	0.536	0.491
LNB/OFA NO_X Emissions (lb/mmBtu)	0.28	0.15	0.15
LNB/OFA + SCR NO_X Emissions (lb/mmBtu)	0.05	0.054	0.049
ESP (Baseline) PM_{10} Emissions (lb/mmBtu)	0.007	0.025	0.040
FF PM_{10} Emissions (lb/mmBtu)	--	0.009	0.008

[1]Baseline emissions data were provided by AEP-PSO. Baseline emission rates (lb/mmBtu) were calculated by dividing the maximum 24-hr lb/hr emission rate by the maximum heat input to the boiler at that emission rate.

[2]Temperature and Velocity were decreased for DFGD and WFGD evaluations. For DFGD, stack temperature was modeled at 349 K and velocity decreased to 15.6 m/s for Unit 3 and 14.67 m/s for Unit 4. For WFGD, stack temperature decreased to 332K and velocity decreased to 14.86 and 13.96 for Units 3 and 4 respectively.

Visibility Post-Processing (CALPOST) Setup

The changes in visibility were calculated using Method 6 with the CALPOST post-processor. Method 6 requires input of monthly relative humidity factors [f(RH)] for each Class I area that is being modeled. Monthly f(RH) factors that were used for this analysis are shown in the table below.

Table 18: Relative Humidity Factors for CALPOST

Month	Wichita Mountains	Caney Creek	Upper Buffalo	Hercules Glade
January	2.7	3.4	3.3	3.2
February	2.6	3.1	3.0	2.9
March	2.4	2.9	2.7	2.7
April	2.4	3.0	2.8	2.7
May	3.0	3.6	3.4	3.3
June	2.7	3.6	3.4	3.3
July	2.3	3.4	3.4	3.3
August	2.5	3.4	3.4	3.3
September	2.9	3.6	3.6	3.4
October	2.6	3.5	3.3	3.1
November	2.7	3.4	3.2	3.1
December	2.8	3.5	3.3	3.3

EPA's default average annual aerosol concentrations for the U.S. that are included in Table 2-1 of EPA's *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program* were to develop natural background estimates for each Class I area.

Visibility Post-Processing Results

Table 19: CALPUFF Visibility Modeling Results for Northeast Units 3 and 4- NO_X

Class I Area	2001	2002	2003	3-Year Average
	98th Percentile Value (Δdv)	98th Percentile Value (Δdv)	98th Percentile Value (Δdv)	98th Percentile Value (Δdv)
Baseline				
Wichita Mountains	0.468	0.402	0.775	0.548
Caney Creek	0.994	0.714	1.029	0.912
Upper Buffalo	0.883	0.42	0.442	0.582
Hercules Glade	0.644	0.345	0.296	0.428
Scenario 1- Combustion Control- LNB/OFA				
Wichita Mountains	0.136	0.116	0.223	0.158
Caney Creek	0.301	0.213	0.293	0.269

Upper Buffalo	0.259	0.124	0.131	0.171
Hercules Glade	0.191	0.102	0.086	0.126

Modeling for SCR controls resulted in an approximate 66% reduction in visibility impairment from scenario one.

Table 20: CALPUFF Visibility Modeling Results for Northeast Units 3 and 4- SO_2

Class I Area	2001	2002	2003	3-Year Average
	98^{th} Percentile Value (Δdv)	98^{th} Percentile Value (Δdv)	98^{th} Percentile Value (Δdv)	98^{th} Percentile Value (Δdv)
Baseline				
Wichita Mountains	1.123	0.819	1.836	1.260
Caney Creek	1.322	1.186	1.245	1.251
Upper Buffalo	0.993	0.683	1.227	0.968
Hercules Glade	1.071	0.626	1.197	0.965
Scenario 1- Dry FGD				
Wichita Mountains	0.164	0.129	0.282	0.192
Caney Creek	0.207	0.199	0.190	0.199
Upper Buffalo	0.141	0.098	0.138	0.126
Hercules Glade	0.138	0.088	0.159	0.128

Wet FGD reduced visibility impairment by a further 50% over Dry FGD. This decreased degradation improved visibility by less 0.12 dv on the 98^{th} percentile days and is considered an insignificant change.

Modeling for existing ESP controls with proposed fabric filters indicate the visibility impairment from direct PM emissions will be improved with the fabric filters but both technologies control visibility impairment well below 0.5dv at all Class I areas.

Table 21: CALPUFF Visibility Modeling Results for Northeast Units 2 NO_X

Class I Area	2001	2002	2003	3-Year Average
	98^{th} Percentile Value (Δdv)	98^{th} Percentile Value (Δdv)	98^{th} Percentile Value (Δdv)	98^{th} Percentile Value (Δdv)
Baseline				
Wichita Mountains	0.366	0.247	0.489	0.367
Caney Creek	0.809	0.66	0.569	0.679
Upper Buffalo	0.541	0.246	0.269	0.352
Hercules Glade	0.495	0.275	0.266	0.345
Scenario 1- Combustion Control- LNB/OFA				
Wichita Mountains	0.144	0.099	0.19	0.144
Caney Creek	0.332	0.267	0.231	0.277
Upper Buffalo	0.218	0.099	0.108	0.142

Hercules Glade	0.195	0.111	0.108	0.138

E. BART DETERMINATION

After considering: (1) the costs of compliance, (2) the energy and non-air quality environmental impacts of compliance, (3) any pollutant equipment in use or in existence at the source, (4) the remaining useful life of the source, and (5) the degree of improvement in visibility (all five statutory factors) from each proposed control technology, the Division determined BART for the three units at the Northeastern Power Plant.

NO_X

New LNB with OFA is determined to be BART for NO_X control for Units 2, 3 and 4 based, in part, on the following conclusions:

1. Installation of new LNB with OFA was cost effective at an average cost effectiveness of $303-313.
2. Combustion control using the LNB/OFA does not require non-air quality environmental mitigation for the use of chemical reagents (i.e., ammonia or urea) and there is minimal energy impact.
3. After careful consideration of the five statutory factors, especially the costs of compliance and existing controls, NO_X control levels on 30-day rolling averages of 0.15 lb/mmBtu for Units 3 and 4 and 0.28 lb/mmBtu on Unit 2 are justified meet the presumptive limits prescribed by EPA.

LNB with OFA and SCR was not determined to be BART for NO_X control for Units 2, 3 and 4 based, in part, on the following conclusions:

1. The cost of compliance for installing SCR on each unit is significantly higher than the cost for LNB with OFA. Additional capital costs for SCR on Units 3 and 4 are on average $290,000,000. Based on projected emissions, SCR could reduce overall NO_X emissions from Northeast Units 3 and 4 by approximately 4,120 TPY beyond combustion controls; however, the incremental cost associated with this reduction is approximately $11,013/ton. SCR controls on Unit 2 would result in an incremental cost of $13,989.
2. Additional non-air quality environmental mitigation is required for the use of chemical reagents.
3. Operation of LNB with OFA and SCR is parasitic and requires power from each unit.
4. The cumulative visibility improvement for SCR, as compared to LNB/OFA across Wichita Mountains and Caney Creek (based on the 98th percentile modeled results) was 0.10 and 0.18 Δdv respectively.

SO_2

Continued use of low sulfur coal is determined to be BART for SO_2 control for Units 3 and 4 based on the capital cost of add-on controls, the cost effectiveness both in $/ton and $/dv of add-on controls, and the long term viability of coal with respect to other environmental programs, and national commitments.

Installation of DFGD is not cost effective. OG&E's revised cost estimates are based on vendor quotes and go well beyond the default methodology recommended by EPA guidance. The cost estimates are credible, detailed, and specific for the Muskogee and Sooner facilities. Cost estimates for the AEP-PSO Northeastern facility continue to be lower on a capital and annualized basis, but are comparable to the costs documented by OG&E. The substantiated AEP-PSO estimate for both boilers at $546,700,000 is $209,240,000 greater than the high end costs assumed by DEQ in the Draft SIP.

These costs put the project well above costs reported for other BART determinations. The federal land managers have informally maintained a spreadsheet of BART costs and determinations for coal-fired facilities. This spreadsheet indicates that the highest reported cost for control was for the Boardman facility in Oregon at a projected cost of $247,300,000. While there is some uncertainty on whether this cost will ultimately be found to be cost effective, it is much lower than the cost of controlling a single boiler at the Muskogee facility ($273,350,000). Most assessments were based on costs of less than $150,000,000 and related cost effectiveness numbers of $3,053/ton removed for Boardman to an average of less than $2,000/ton for the other determinations tracked by the FLMs.

Table 20 provides a summary of the baseline SO_2 emission rates included in several BART evaluations.

Table 22: Comparison of Baseline SO_2 Emissions at Several BART Units

Station	Baseline SO_2 Emission Rate (lb/mmBtu)	Baseline SO_2 Emissions (TPY)
Muskogee Unit 4	0.507	9,113
Muskogee Unit 5	0.514	9,006
Sooner Unit 1	0.509	9,394
Sooner Unit 2	0.516	8,570
NPPD Gerald Gentleman Unit 1	0.749	24,254
NPPD Gerald Gentleman Unit 2	0.749	25,531
White Bluff Unit 1	0.915	31,806
White Bluff Unit 2	0.854	32,510
Boardman unit 1	0.614	14,902
Northeastern Unit 3	0.900	16,000
Northeastern Unit 4	0.900	16,000
Naughton Unit 1	1.180	8,624
Naughton Unit 2	1.180	11,187
OPPD Nebraska City Unit 1	0.815	24,191

Assuming total annual costs and projected emissions are similar and thereby setting aside the issues related to pre-2008 cost estimates and the ability to compare them to December 2009 estimates, cost effectiveness will be a function of the baseline emissions. This holds true for units firing subbituminous coals with baseline SO_2 emissions rates in the range of 0.5 lb/mmBtu to approximately 2.0 lb/mmBtu, because removal efficiencies achievable with DFGD control will vary based on inlet SO_2 loading. In general, DFGD control systems are capable of achieving higher removal efficiencies on units with higher inlet SO_2 loading. DFGD control systems will be more cost effective on units with higher baseline SO_2 emissions because the control systems will be capable of achieving higher removal efficiencies and remove more tons of SO_2 per year for similar costs. Conversely, DFGD will be less cost effective, on a $/ton basis, on units with lower SO_2 baseline emissions. On the basis of baseline emissions alone, with all other factors being equal, the cost effectiveness of the AEP-PSO units after adopting and annual average emission rate of 0.55 lb/mmBtu would be about 55 to 185% higher than the other units listed, i.e., less cost effective.

The average cost effectiveness at Northeastern for DFGD is $3,294 per ton of SO_2 removed from the present baseline and $6,146 per ton from the lower sulfur coal baseline for each unit over a twenty year operational life. The cost of add-on controls above and beyond lower sulfur coal at the Northeastern facility is well above the average cost effectiveness reported for similar BART projects, well above costs associated with BACT determinations for SO_2, and well above the cost of control originally contemplated in the Regional Haze Rule.

From the FLM BART tracking spreadsheet, the average cost effectiveness in $/dv was $5,700,000/dv. The addition of DFGD at the Northeastern Facility was anticipated to reduce impairment by 3.97 dv. Importantly, the cost effectiveness of that improvement is calculated to be $21,829,547/dv.

A majority of the Class I areas are located in the western part of the U.S. Simply due to the number of Class I areas in the west, it is likely that a BART applicable unit located in the western U.S. will be closer to a Class I area, and that emissions from the unit will affect visibility at more Class I areas. For example, the Boardman Generating Station located in the north central region approximately 150 miles east of Portland, is located within 300 km of 14 Class I areas. By comparison the Northeastern station is located with 300 km of 3 Class I areas. Using the sum of modeled visibility improvements at all 14 Class I areas, cost effectiveness of the DFGD control system would be $3,690,510/dv or 5.9 times more cost effective than DFGD controls at the Northeastern facility. The federal land managers have indicated that costs effectiveness numbers of less than $10,000,000/dv should be considered cost effective. While this does not prohibit a determination of cost effectiveness at numbers greater than $10,000,000/dv, it does imply that numbers greater than that should receive greater consideration.

An investment of this magnitude to install DFGD on an existing coal-fired power plant effectively guarantees the continued use of coal as the primary fuel source for energy generation in this facility and arguably the state for the next 20 years and beyond. Therefore, a determination in support of DFGD ignores the Obama Administration's stated agenda to control carbon dioxide and other green house gases by restricting the alternatives left open to AEP-PSO and hence the ratepayers of Oklahoma. Substantial uncertainty currently exists about the nature and costs of future federal carbon controls on power plants, including the level of stringency, timing, emissions allowance allocation and prices, and whether and to what degree emissions "offsets" are allowed. Further, new federal MACT mercury control requirements may be imposed on the AEP-PSO facility that would be more stringent than the scrubber can deliver. Fortunately, other technology options now exist that would likely achieve greater mercury reductions at lower cost than the scrubber. If EPA determines that MACT requires greater reductions than those achieved through DFGD, then ratepayers would be at risk to pay for additional required mercury control technology.

The cost for DFGD is too high, the benefit too low and these costs, if borne, further extend the life expectancy of coal as the primary fuel in the AEP-PSO facility for at least 20 years and beyond. BART is the use of low sulfur coal (0.55 lb/mmBtu- annual average)..

Wet FGD was not determined to be BART for SO_2 control for Units 3 and 4 based, in part, on the following conclusions:

1. The cost of compliance for installing WFGD on each unit is higher than the cost for Dry FGD. Based on projected emissions, WFGD could reduce overall SO_2 emissions from Northeast Units 3 and 4 by approximately 3,200 TPY beyond dry scrubbers; however, the incremental cost associated with this reduction is approximately $6,356/ton without appreciable visibility improvement.
2. SO_3 remaining in the flue gas will react with moisture in the wet FGD to generate sulfuric acid mist. Sulfuric acid is classified as a condensable particulate. Condensable particulates from the wet FGD system can be captured using additional emission controls (e.g., WESP). However, the effectiveness of a WESP system on a subbituminous fired unit has not been demonstrated and the additional cost of the WESP system significantly increases the cost of SO_2 controls.
3. Wet FGD systems must be located downstream of the unit's particulate control device; therefore, dissolved solids from the wet FGD system will be emitted with the wet FGD plume. Wet FGD control systems also generate lower stack temperatures that can reduce plume rise and result in a visible moisture plume.
4. Wet FGD systems use more reactant (e.g., limestone) than do dry systems, therefore the limestone handling system and storage piles will generate more fugitive dust emissions.
5. Wet FGD systems require significantly more water than the dry systems and generate a wastewater stream that must be treated and discharged. Wet FGD wastewater treatment systems typically require calcium sulfate/sulfite desaturation, heavy metals precipitation, coagulation/precipitation, and sludge dewatering. Treated wastewater is typically discharged to surface water pursuant to an NPDES discharge permit, and solids are typically disposed of in a landfill. Dry FGD control systems are designed to evaporate water within the reaction vessel, and therefore do not generate a wastewater stream.

PM_{10}

The existing ESP control is determined to be BART for PM_{10} controls for Units 3 and 4 based on the determination of low sulfur coal and the high cost of fabric filters relative to the low actual emissions of PM_{10} from the facility.

Table 23: Unit-by-unit BART determinations

Control	Unit 2	Unit 3	Unit 4
NO_X Control	LNB with OFA	LNB with OFA	New LNB with OFA
Emission Rate (lb/mmBtu)	0.28 lb/mmBtu (30-day rolling average)	0.15 lb/mmBtu (30-day rolling average)	0.15 lb/mmBtu (30-day rolling average)
Emission Rate lb/hr	1331 lb/hr (30-day rolling	716 lb/hr (30-day rolling	716 lb/hr (30-day rolling

	average)	average)	average)
Emission Rate TPY	5,830 TPY (12-month rolling)	6,274 TPY (12-month rolling)	
SO_2 Control	--	Low Sulfur Coal	Low Sulfur Coal
Emission Rate (lb/mmBtu)	--	0.65 lb/mmBtu (30-day rolling average)	0.65 lb/mmBtu (30-day rolling average)
Emission Rate lb/hr	--	3,104 lb/hr (30-day rolling average)	3,104 lb/hr (30-day rolling average)
Emission Rate (lb/mmBtu)	--	0.55 lb/mmBtu (12-month rolling average)	0.55 lb/mmBtu (12-month rolling average)
Emission Rate (TPY)		23,006 TPY	
PM_{10} Control[1]	--	ESP	ESP
Emission Rate (lb/mmBtu)	--	0.1 lb/mmBtu (3-hour rolling average)	0.1 lb/mmBtu (3-hour rolling average)
Emission Rate lb/hr	--	478 lb/hr (3-hour rolling average)	478 lb/hr (3-hour rolling average)
Emission Rate TPY	--	4,183 TPY (12-month rolling average)	

[1]Current emissions limits for ESPs are based on minimum NSPS requirements for front half catch and do not reflect the true emissions. As part of the permitting process, AEP-PSO will be required to propose emission limits for both front and back half, which is reflective of the control technology and consistent with the performance tests.

F. CONTINGENT BART DETERMINATION

In the event that EPA disapproves the BART Determination referenced above in regard to the DEQ determination that DFGD with SDA is not cost-effective for SO_2 control, the low-sulfur coal requirement in the BART determination for SO_2 and the related ESP requirement for PM referenced above shall be replaced with a requirement that Northeastern Units 3 and 4 install DFGD with SDA for SO_2 control or meet the corresponding SO_2 emission limits listed below by December 31, 2018 or comply with the approved alternative described in section G (Greater Reasonable Progress Alternative).

Table 24: Unit-by-unit Contingent BART determinations

Control	Unit 3	Unit 4
SO_2 Control	DFGD w/SDA	DFGD w/SDA
Emission Rate (lb/mmBtu)	0.1 lb/mmBtu (30-day rolling average)	0.1 lb/mmBtu (30-day rolling average)
Emission Rate lb/hr	478 lb/hr (30-day rolling average)	478 lb/hr (30-day rolling average)
Emission Rate TPY	2,091 TPY	2,091 TPY

The "contingent" BART as defined here and in conjunction with the greater reasonable progress alternative recognizes the long term importance of achieving reductions in SO_2 while addressing the need for operational flexibility in response to the eventualities of a federal carbon trading program and mercury MACT in the nearer term. It must be understood that DEQ has determined that DFGD is not cost effective. However, if EPA chooses to ignore that element of the BART determination, DEQ does agree that DFGD remains a technically feasible control option for SO_2 reductions.

Switching from coal to natural gas, while physically possible constitutes a significant modification to a facility process not contemplated by the regional haze rule. However, exploring some combination of both options, while allowing the uncertainty surrounding other federal environmental programs to settle, is a more equitable alternative for the ratepayers in Oklahoma than requiring an overly costly control merely to achieve limited visibility improvement while simultaneously solidifying the use of a higher emitting technology from now into the foreseeable future.

G. GREATER REASONABLE PROGRESS ALTERNATIVE DETERMINATION

In lieu of installing and operating BART for SO_2 Northeastern Units 3 and 4, AEP-PSO may elect to implement a fuel switching alternative. The greater reasonable progress alternative requires AEP-PSO to achieve a combined annual SO_2 emissions limit (identified in table 25) by installing and operating DFGD with SDA on one of the two boilers and being at or below the SO_2 emission that would result from switching the remaining boiler to natural gas. Under this alternative AEP-PSO shall install the controls (i.e., DFGD with SDA or achieve equivalent emissions) by December 31, 2026. By adopting these emission limits, DEQ and AEP-PSO expect the cumulative SO_2 emissions from Northeastern Units 1 and 2 to be approximately 43% less than would be achieved through the installation and operation of DFGD with SDA at both units.

Table 25: SO_2 Emissions with Greater Reasonable Progress

Parameter	Northeastern Unit 3 and Unit 4
BART (Low Sulfur Coal)	23,006 TPY
Contingent BART (DFGD)	4,182 TPY
GRP (DFGD/Natural Gas)	2,400 TPY

Under no circumstance will the Greater Reasonable Progress Plan result in less visibility improvement than would be achieved either through the DEQ determined BART or the "contingent" BART. By allowing the installation of SO_2 controls to be delayed, current regulatory hurdles to long term natural gas contracts can be addressed and the best interests of the ratepayers and visitors to our Class I areas can be preserved for the long term 2064 goal of natural visibility.

V. CONSTRUCTION PERMIT

Prevention of Significant Deterioration (PSD)

Northeastern Power Plant is a major source under OAC 252:100-8 Permits for Part 70 Sources. AEP-PSO should comply with the permitting requirements of Subchapter 8 as they apply to the installation of controls determined to meet BART.

The installation of controls determined to meet BART will not change NSPS or NESHAP/MACT applicability for the gas-fired units at the Northeastern Station. The permit application should contain PM_{10} and $PM_{2.5}$ emission estimates for filterable and condensable emissions.

VI. OPERATING PERMIT

The Northeastern Power Plant is a major source under OAC 252:100-8 and has submitted an application to modify their existing Title V permit to incorporate the requirement to install controls determined to meet BART. The Permit will contain the following specific conditions:

1. The boilers in EUG 2, 3 and 4 are subject to the Best Available Retrofit Technology (BART) requirements of 40 CFR Part 51, Subpart P, and shall comply with all applicable requirements including but not limited to the following: [40 CFR §§ 51.300-309 & Part 51, Appendix Y]

a. Affected facilities. The following sources are affected facilities and are subject to the requirements of this Specific Condition, the Protection of Visibility and Regional Haze Requirements of 40 CFR Part 51, and all applicable SIP requirements:

EU ID#	Point ID#	EU Name	Heat Capacity (MMBTUH)	Construction Date
2	2	Babcock and Wilcox UP-60	4754	1970
3	3	Combustion Engineering #4974 SCRR	4775	1974
4	4	Combustion Engineering #7174 SCRR	4775	1974

b. Each existing affected facility shall install and operate the SIP approved BART as expeditiously as practicable but in no later than five years after approval of the SIP incorporating the BART requirements.

c. The permittee shall apply for and obtain a construction permit prior to modification of the boilers. If the modifications will result in a significant emission increase and a significant net emission increase of a regulated NSR pollutant, the applicant shall apply for a PSD construction permit.

d. The affected facilities shall be equipped with the following current combustion control technology, as determined in the submitted BART analysis, to reduce emissions of NO_X to below the emission limits below:

   i. New Low-NO_X Burners,

   ii. Overfire Air.

e. The permittee shall maintain the controls (Low-NO_X burners, overfire air and ESP) and establish procedures to ensure the controls are properly operated and maintained.

f. Within 60 days of achieving maximum power output from each affected facility, after modification or installation of BART, not to exceed 180 days from initial start-up of the affected facility the permittee shall comply with the emission limits established in the construction permit. The emission limits established in the construction permit shall be consistent with manufacturer's data and an agreed upon safety factor. The emission limits established in the construction permit shall not exceed the following emission limits:

EU ID#	Point ID#	NO_X	Averaging Period
2	2	0.28 lb/mmBtu	30-day rolling

EU ID#	Point ID#	NO_X Emission Limit	SO_2 Emission Limit	Averaging Period
3	3	0.15 lb/mmBtu	0.65 lb/mmBtu	30-day rolling
4	4	0.15 lb/mmBtu	0.65 lb/mmBtu	30-day rolling

EU ID#	Point ID#	SO_2 Emission Limit	SO_2 Emission Limit	Averaging Period
3	3	0.55 lb/mmBtu	23,006 TPY	annual average
4	4	0.55 lb/mmBtu		annual average

g. Boiler operating day shall have the same meaning as in 40 CFR Part 60, Subpart Da.

h. Within 60 days of achieving maximum power output from each boiler, after modification of the boilers, not to exceed 180 days from initial start-up, the permittee shall conduct performance testing as follows and furnish a written report to Air Quality. Such report shall document compliance with BART emission limits for the affected facilities. [OAC 252:100-8-6(a)]

  i. The permittee shall conduct SO_2, NO_X, PM_{10}, $PM_{2.5}$, CO, and VOC testing on the boilers at 60% and 100% of the maximum capacity. NOX and CO testing shall also be conducted at least one additional intermediate point in the operating range.

  ii. Performance testing shall be conducted while the units are operating within 10% of the desired testing rates. A testing protocol describing how the testing will be performed shall be provided to the AQD for review and approval at least 30 days prior to the start of such testing. The permittee shall also provide notice of the actual test date to AQD.