Oklahoma Department of Environmental Quality
Air Quality Division

Revised BART Determination **March 19, 2013**

COMPANY:	**AEP-Public Service Company of Oklahoma**
FACILITY:	**Northeastern Power Plant**
FACILITY LOCATION:	**Rogers County, Oklahoma**
TYPE OF OPERATION:	**Two 490 MW Coal-Fired Steam Electric Generating Units (Units 3 & 4)**
REVIEWERS:	**Lee Warden, Engineering Manager**

I. PURPOSE

U.S. Environmental Protection Agency (EPA) published the final decision to partially approve and partially disapprove the Oklahoma Regional Haze (RH) State Implementation Plan (SIP) and simultaneously issue a Federal Implementation Plan (FIP) on December 28, 2011. *See* 76 Fed.Reg. 81727 (Dec. 28, 2011). The FIP became effective on January 27, 2012. The FIP established Dry Flue Gas Desulfurization with a Spray Dry Absorber (DFGD/SDA) as the Best Available Retrofit Technology (BART) for SO_2 emissions control from American Electric Power (AEP) - Public Service Company of Oklahoma (PSO or AEP/PSO) Northeastern Units 3 and 4. The DEQ-determined controls for NO_X and PM_{10}, low NO_X burners with over-fire air (LNB w/ OFA) and continued use of existing electrostatic precipitators (ESP) were approved. The decision also approved DEQ's BART determination for the AEP/PSO Northeastern Unit 2, a 495 MW gas-fired unit. Subsequent to publishing the final FIP, AEP/PSO, DEQ, EPA, and the U.S. Department of Justice entered discussions on alternatives to DFGD/SDA that would provide the necessary visibility improvements. Notice of the proposed settlement agreement was published in the Federal Register on November 14, 2012 (77 Fed.Reg. 67814). The settlement agreement, partially summarized below, is the result of these discussions. On November 20, 2012, AEP/PSO submitted Supplemental BART Determination Information under terms of the settlement agreement. The purpose of this review is to document that the agreed-upon control scheme meets the requirements of the BART review and will serve to replace the disapproved portions of the corresponding BART Submittal Analysis in Oklahoma's RH SIP.

II. SETTLEMENT AGREEMENT

The final agreement lays out a plan for AEP/PSO to shut down one of the two units by April 16, 2016, and install and operate a dry sorbent injection system (DSI) on the other unit from April 16, 2016 to December 31, 2026, at which point AEP/PSO would shut down the remaining unit.

In compliance with the 2010 BART determination and in anticipation of federal requirements, AEP/PSO completed installation of new LNB w/ OFA. The settlement agreement acknowledges these NO_X reductions and provides for limits on NO_X and SO_2 emissions prior to the SIP/FIP deadlines for installation and operation of BART controls. The limits assume full load operation of both units until April 16, 2016 and continued use of low sulfur coal. Table 1 identifies the limits and timelines from the settlement agreement for the early NO_X and SO_2 emission reductions.

Table 1: Early NO_X and SO_2 Reductions

Settlement Agreement-Early Reductions		
By December 31, 2013	**Unit 3**	**Unit 4**
NO_X Control	LNB w Separated OFA	LNB w Separated OFA
Emission Rate (lb/mmBtu)	0.23 lb/mmBtu (30-day rolling average)	0.23 lb/mmBtu (30-day rolling average)
Emission Rate lb/hr	1,098 lb/hr (30-day rolling average)	1,098 lb/hr (30-day rolling average)
Emission Rate TPY	9,620 TPY (12-month rolling)	
By January 31, 2014	**Unit3**	**Unit 4**
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)
By December 31, 2014	**Unit3**	**Unit 4**
SO_2 Control	Low Sulfur Coal	Low Sulfur Coal
Emission Rate (lb/mmBtu)	0.60 lb/mmBtu (12-month rolling average)	0.60 lb/mmBtu (12-month rolling average)
Emission Rate (TPY)	25,097 TPY	

The settlement agreement includes a required shutdown date for both units and requires controls based on the remaining useful life of each unit. The FIP required installation of DFGD/SDA on both units within 5 years of its effective date, January 27, 2012. This would require controls to be installed and operational by January of 2017.

The settlement agreement requires AEP/PSO to shut down one unit by April 16, 2016, prior to the FIP-required control date. The settlement agreement requires AEP/PSO to shut down the second unit by December 31, 2026, and relies upon the remaining useful life of the unit to justify installation of DSI for SO_2 emissions control in lieu of the more costly DFGD/SDA specified in the FIP. To further reduce emissions, AEP/PSO will restrict capacity utilization over the remaining life of the unit. The settlement agreement requires capacity utilization reductions beginning in the year 2021.

The settlement agreement provides for the possibility of an earlier shutdown of the second unit, contingent on an analysis of projected costs from natural gas or renewable resources conducted in calendar year 2021. However, the evaluations of cost and visibility improvement relied upon in this revised BART Determination do not take into account the possibility of an earlier shutdown.

Due to increased particle loading, the installation of DSI will necessitate the addition of a fabric filter baghouse. The BART determination in the 2010 SIP required no further controls and a continued reliance on the electrostatic precipitator (ESP). The proposal for DSI, while forcing further PM controls, does not open the prior PM BART determination for additional review.

Tables 2 and 3 identify the limits and timeline for the proposed BART control for SO_2, the timeline for early compliance with the approved NO_X BART control, and the required decreases in capacity utilization through the useful life of the remaining unit.

Table 2: Revised SO_2 BART

BART Control with Unit Shutdown	
By April 16, 2016	**Remaining Unit**
SO_2 Control	**Dry Sorbent Injection with Activated Carbon Injection**
Emission Rate (lb/mmBtu)	0.4 lb/mmBtu (30-day rolling average)
Emission Rate lb/hr	1,910 lb/hr (30-day rolling average)
Emission Rate TPY	8,366 TPY
NOx Control	**LNB w/ Separated OFA (Further Control System Tuning)**
Emission Rate (lb/mmBtu)	0.15 lb/mmBtu (30-day rolling average)
Emission Rate (lb/hr)	716 lb/hr (30-day rolling average)
Emission Rate TPY	3,137 TPY

Table 3: Further Reductions

Further Reasonable Progress over Remaining Unit Life		
	NO_X	**SO_2**
January 1, 2021 70% Utilization	2,196 TPY	5,856 TPY
January 1, 2023 60% Utilization	1,882 TPY	5,019 TPY
January 1, 2025 50% Utilization	1,569 TPY	4,183 TPY
December 31, 2026	Unit Shutdown	

III. BART-ELIGIBLE AND BART-SUBJECT DETERMINATION

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 (OAC 252:100-8-73). Visibility impact modeling conducted by AEP/PSO as part of the initial BART review determined that the maximum predicted visibility impacts from Northeast Units 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 3 and 4 were determined to be BART applicable sources, subject to the BART determination requirements.

IV. BEST AVAILABLE RETROFIT TECHNOLOGY (BART) ANALYSIS STEPS

Guidelines for making BART determinations are included in Appendix Y of 40 C.F.R. 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, 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 and was approved in the final SIP/FIP action. Appendix Y does not establish a BART presumptive emission limit for PM.

Potentially available control options designed to remove SO_2 from coal-fired combustion gases were identified and reviewed in the original BART Application Analysis dated January 16, 2010 and EPA's FIP evaluation. EPA concluded in the FIP that DFGD/SDA satisfied the BART review requirements; therefore, no further analysis of Wet Flue Gas Desulfurization is necessary. Likewise, those technologies previously deemed technically infeasible are not under review again.

Table 4: List of Potential Control Options

Control Technology
Dry Sorbent Injection
Dry Flue Gas Desulfurization-Spray Dryer Absorber

Post-Combustion Flue Gas Desulfurization:

Dry Flue Gas Desulfurization

DFGD is a dry scrubbing system that has been designed to remove SO_2 from coal-fired combustion gases. 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, DFGD systems produce a dry byproduct that must be removed with the fly ash in the particulate control equipment. Therefore, DFGD systems must be located upstream of the particulate control device to remove the reaction products and excess reactant material.

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 Northeastern 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 FGD designed as SDA could achieve a controlled SO_2 emission rate of 0.15 lb/mmBtu (30-day average) or less on an on-going long-term basis.

Dry Sorbent Injection

DSI involves the injection of a sorbent, or reagent (e.g., sodium bicarbonate) into the exhaust gas stream upstream of a particulate control device. The SO_2 reacts with the reagent and the resulting particle is collected in the particulate control system. The process was developed as a lower cost FGD option because the existing ductwork acts as the absorber vessel, removing the need to install a new, separate absorber vessel. Depending on the residence time, gas stream temperature, and limitations of the particulate control device, sorbent injection control efficiency can range between 40 and 60 percent.[1]

Table 5: Technically Feasible SO_2 Control Technologies - Northeastern Power Station

	Northeastern Unit 3	**Northeastern Unit 4**
Control Technology	**Approximate SO_2 Emission Rate (lb/mmBtu)**	**Approximate SO_2 Emission Rate (lb/mmBtu)**
Dry FGD- Spray Dryer Absorber[1]	0.06	0.06
Dry Sorbent Injection	0.4	-
Baseline	0.9	0.9

[1]The DFGD/SDA emission rate listed is reflective of the FIP control determination and presumably achievable.

[1] "Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers ,Cement Plants and Paper and Pulp Facilities" Northeast States for Coordinated Air Use Management (NESCAUM), March 2005.

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 Control Cost Manual, Sixth Edition ("the Manual"). The capital and operating costs of the DSI control option, i.e., the Settlement Agreement scenario, were estimated based on the Manual except as listed below.

- *Purchased Equipment Costs*, *Site Preparation Costs*, and *Building Costs* were based on an approximate six-month, site-specific, feasibility and conceptual engineering and design effort that resulted in a Class 4 AACE category budgetary estimate.
- *Operating Labor Costs*, *Maintenance Labor Costs*, and *Other Direct Operating Costs* (e.g., for sorbent usage, electricity, and bag and cage replacement) were based on an evaluation of annual operating and maintenance cost project impact as part of the above-mentioned feasibility and conceptual design effort.
- The *Indirect Operating Costs* of *Overhead*, *Property Tax*, and *Insurance* were based on the same calculation methodologies presented in EPA's Technical Support Document (TSD) published with the RH FIP. These methodologies deviate from the Manual but were used for the purpose of consistency with the FIP.

The capital recovery factor used to estimate the annual cost of control of the DFGD/SDA option was based on a 7% interest rate and a control life of 30 years. Annual operating costs and annual emission reductions were calculated assuming a capacity factor of 85%.

The capital costs for the DSI option were annualized over a 10-year period and then added to the annual operating costs to obtain the total annualized costs. An equipment life of 10 years was used because the controls will only be in operation for 10 years, from 2016 to 2026, before the unit is shut down. Further, the capacity factor will decrease over the 10 year period. However, the facility will not be taking a limit on capacity until 2021; therefore, the cost analyses are based on an 85% capacity factor to be consistent with baseline actual capacity usage and with all previous evaluations.

Table 6: Economic Cost for Unit 3 and 4 - Dry FGD w/ Spray Dryer Absorber

Cost	DFGD/SDA
Total Capital Investment ($)	$274,100,000
Total Capital Investment ($/kW)	$280
Capital Recovery Cost ($/Yr)	$22,088,733
Annual O&M Costs ($/Yr)	$15,040,231
Total Annual Cost ($)	$44,969,595

Table 7: Economic Cost for Unit 3 – DSI

Cost	DSI
Total Capital Investment ($)	$111,332,077
Total Capital Investment ($/kW)	$227
Capital Recovery Cost ($/Yr)	$15,851,183
Annual O&M Costs ($/Yr)	$5,972,469
Total Annual Cost ($)	$25,008,306

Table 8: Environmental Costs for Unit 3 and 4

	Baseline	DSI	DFGD/SDA
SO_2 Emission Rate (lb/mmBtu)	0.9	0.4	0.06
Annual SO_2 Emission (TPY)[1]	31,999	7,111	2,880
Annual SO_2 Reduction (TPY)	--	24,888	29,119
Total Annual Cost ($)		$25,008,306	$44,969,595
Cost per Ton of Reduction		$1,005/ton	$1,544/ton

[1]Baseline annual emissions were averaged based on annual emissions from 2004- 2006. Projected annual emissions for DFGD/SDA option were calculated based on the controlled SO_2 emissions rate (a 91% reduction from the baseline). Projected annual emissions for DSI option were calculated based on the controlled SO_2 emissions rate, full load heat input of 4,775 mmBtu/hr, and assuming a 85% capacity factor.

The fifth step for a BART determination analysis, as required by 40 C.F.R. Part 51, Appendix Y, is to evaluate 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 Units 3 and 4 by using an EPA-approved dispersion modeling system (CALPUFF) to predict the change in Class I area visibility.

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 considering meteorological and terrain factors. Wichita Mountain Wildlife Refuge, Caney Creek, Upper Buffalo and Hercules Glade are the closest Class I areas to the Northeastern Power Plant. 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.

DESCRIPTION OF BART SOURCES AND MODELING APPROACH

In accordance with EPA guidelines in 40 C.F.R. Part 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 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.

Table 9: Northeastern Power Plant - Modeling Parameters for BART Evaluation

Parameter	Northeastern Unit 3		Northeastern Unit 4	
Plant Configuration	Coal-Fired Boiler		Coal-Fired Boiler	
Firing Configuration	Tangentially-fired		Tangentially-fired	
Gross Output (nominal)	490 MW		490 MW	
Design Input to Boiler	4,775 mmBtu/hr		4,775 mmBtu/hr	
Maximum 24-hour Average Input	5,812 mmBtu/hr		5,594 mmBtu/hr	
Primary Fuel	Sub-bituminous coal		Sub-bituminous coal	
Existing NO_X Controls	1st Generation LNB/OFA		1st Generation LNB/OFA	
Existing PM_{10} Controls	Electrostatic precipitator		Electrostatic precipitator	
Existing SO_2 Controls	Low-sulfur coal		Low-sulfur coal	
Baseline Emissions				
	Unit 3		**Unit 4**	
	lb/hr	**lb/mmBtu**	**lb/hr**	**lb/mmBtu**
NO_X	3,116	0.536	2,747	0.491
SO_2	6,126	1.054	5,930	1.06
SIP Approved Emissions (Max 24-hour)				
	lb/hr	**lb/mmBtu**	**lb/hr**	**lb/mmBtu**
NO_X	872	0.15	839	0.15
Unit 4 Shut Down/Unit 3 NO_X Controlled, SO_2 Baseline (Max 24-hour)				
	lb/hr	**lb/mmBtu**	**lb/hr**	**lb/mmBtu**
NO_X	872	0.15	-	-
SO_2	6,126	1.054	-	-
Unit 4 Shut Down/Unit 3 NO_X Controlled, SO_2 DSI Control (Max 24-hour)				
NO_X	872	0.15	-	-
SO_2	2,325	0.4	-	-

REFINED MODELING

AEP/PSO was required to conduct a refined BART analysis that included CALPUFF visibility modeling for the facility. The modeling approach followed the modeling conducted in support of the Federal Implementation Plan (FIP) and as described in the protocol submitted to DEQ on October 3, 2012.

CALPUFF System

Predicted visibility impacts from the Northeastern Power Plant were determined using the EPA CALPUFF modeling system, which is the EPA-preferred modeling system for long-range transport.

Table 10: Key Programs in CALPUFF System

Program	Version	Level
CALMET	5.53a	040716
CALPUFF	5.8	070623
CALPOST	6.221	080724

Meteorological Data Processing (CALMET)
The existing meteorological dataset has been recently reviewed and approved for use by EPA, and formed the foundation for the analyses conducted in support of the FIP. In order to maintain a consistent basis for comparison with previous studies and with the presumption that a model update would not significantly impact an analysis of the relative change between the baseline and control scenarios, the CALMET processing was not updated as part of these analyses.

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

Table 11: Source Parameters

	Baseline[1]	
Parameter	Coal-Fired Unit 3	Coal-Fired Unit 4
Heat Input (mmBtu/hr)	5,812	5,594
Stack Height (m)	183	183
Stack Diameter (m)	8.23	8.23
Stack Temperature (K)	424	415
Exit Velocity (m/s)	18.97	17.46
Baseline SO_2 Emissions (lb/mmBtu)	1.054	1.060
Dry Sorbent Injection	0.4	-
Baseline NO_X Emissions (lb/mmBtu)	0.536	0.491
LNB/OFA NO_X Emissions (lb/mmBtu)	0.15	-

[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.

Visibility Post-Processing (CALPOST) Setup
The changes in visibility were calculated using Method 8 with the CALPOST post-processor. Method 8 incorporates the use of the new IMPROVE (Interagency Monitoring of Protected Visual Environments) equation for predicting light extinction, as found in the 2010 FLAG (*Federal Land Managers Air Quality Related Values Workgroup*) guidance. 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 used to develop natural background estimates for each Class I area.

VISIBILITY POST-PROCESSING RESULTS

Table 12: CALPUFF Visibility Modeling Results for Northeast Units 3 and 4- SO_2 and NO_X

Class I Area	2001 98th Percentile Value (Δdv)	2002 98th Percentile Value (Δdv)	2003 98th Percentile Value (Δdv)	3-Year Average 98th Percentile Value (Δdv)
Baseline				
Wichita Mountains	1.228	1.339	1.937	1.501
Caney Creek	1.927	1.290	1.664	1.627
Upper Buffalo	1.389	0.938	1.180	1.169
Hercules Glade	1.179	0.867	1.291	1.112
Unit 4 Shut Down and DSI on Unit 3 (NO_X Baseline)				
Wichita Mountains	0.417	0.356	0.618	0.464
Caney Creek	0.637	0.439	0.584	0.553
Upper Buffalo	0.534	0.293	0.379	0.402
Hercules Glade	0.408	0.291	0.298	0.332
Unit 4 Shut Down and DSI/LNB/OFA on Unit 3				
Wichita Mountains	0.241	0.271	0.372	0.295
Caney Creek	0.346	0.240	0.297	0.294
Upper Buffalo	0.247	0.172	0.231	0.216
Hercules Glade	0.213	0.170	0.246	0.209

Table 13: CALPUFF Visibility Modeling Results for Northeast Units 3 and 4- SO_2 and NO_X

Class I Area	2001 98th Percentile Value (Δdv)	2002 98th Percentile Value (Δdv)	2003 98th Percentile Value (Δdv)	3-Year Average 98th Percentile Value (Δdv)
EPA FIP – DFGD/SDA Units 3 and 4				
Wichita Mountains	0.187	0.163	0.257	0.202
Caney Creek	0.227	0.196	0.252	0.225
Upper Buffalo	0.238	0.129	0.139	0.169
Hercules Glade	0.197	0.129	0.119	0.148

V. BART DETERMINATION

SO_2

DEQ considered: (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, to determine BART for the two coal-fired units at the Northeastern Power Plant.

As stated in the November 20, 2012 Supplemental BART Determination Information submitted by AEP/PSO, the company intends to shut down one of the two identical units (preliminarily determined to be Northeastern Unit 4) prior to the expiration of the five year period from the FIP effective date, and to shut down the second unit (preliminarily determined to be Northeastern Unit 3) no later than December 31, 2026. In consideration of the shortened lifespans of the units, continued use of low sulfur coal with a DSI system is determined to be BART for SO_2 control.

In general, BART is considered to be a unit-by-unit evaluation. However, in order to more accurately contrast the environmental benefits of one solution versus another, the settlement agreement control strategy through the BART timeframe is reviewed as a BART solution and contrasted against the FIP scenario through the same time period.

The cost effectiveness in dollars per ton of SO_2 removed for the settlement agreement scenario is $1,005 per ton, and for the FIP scenario, $1,544 per ton. Given the projected level of emission reductions of 24,888 tons per year versus 29,119 tons per year, respectively, the incremental cost effectiveness to achieve the further reductions of the FIP scenario is $4,718 per ton in the first year and with decreased capacity utilization under the settlement agreement, the incremental cost effectiveness worsens.

A DFGD/SDA solution would provide improvements in visibility above that achieved with a DSI system. However, factoring in the full settlement agreement, these incremental reductions in emissions of SO_2 do not result in a perceptible improvement in visibility either on an individual Class I area basis or a cumulative Class I area basis. The FIP scenario would result in imperceptibly greater improvements of approximately 0.1dv over individual Class I areas and an average total improvement of 0.27 across the four nearest Class I areas during the time of control implementation. Visibility improvements must be 1 dv or greater to be perceptible to the human eye. These imperceptible improvements would be achieved at a much greater cost. The cost effectiveness for the FIP scenario in terms of visibility improvement across all modeled Class I areas is $9,639,785 per dv versus the cost effectiveness of the settlement agreement scenario, $5,690,172 per dv.

The settlement agreement requires the shutdown of Northeastern Unit 4, and therefore the removal of NO_X, SO_2, PM, and CO_{2e} emissions from the unit. These reductions will help to address local formation and interstate transport of ozone and reduce the contribution to greenhouse gases and mercury deposition from electricity generation in Oklahoma. The FIP scenario provides no further improvement in ozone and would likely assure continued use of coal-fired electricity generation for an additional 20 years beyond the settlement agreement scenario. Additionally, the settlement agreement scenario, while achieving perceptively equivalent visibility improvements at the Class I areas, will not require water usage and in shutting down Northeastern Unit 4 rather than installing additional controls, energy consumption is half that of the control solution established by the FIP.

Given the comparable visibility improvement, lower costs, and overall reduced environmental impact, the scenario described in the settlement agreement and documented in Table 2 constitutes BART.

NO_X

DEQ established the BART NO_X emission limit applicable to Northeastern Units 3 and 4 as 0.15 lb/mmBtu (30-day rolling average) in the 2010 Regional Haze SIP. The control technology and emission limits were approved in the final SIP/FIP action. The original Regional Haze Agreement required installation and operation of the controls within 5 years of SIP approval. The settlement agreement does not reopen the NO_X technology determination, but does require earlier installation and compliance with reduced emission limits prior to the original SIP-imposed deadline. With the settlement agreement, the facility is required to comply with an emission limit of 0.23lb/MMBtu on a 30-day rolling average from December 31, 2013 until April 16, 2016; thereafter, the remaining unit must comply with the BART emission limit of 0.15lb/MMBtu on a 30-day rolling average. This early implementation schedule reducing emissions by 43% will provide previously unanticipated improvements in visibility as well as reductions in local formation and interstate transport of ozone.

The following table provides a summary of the BART controls and limits.

Table 14: BART Controls and Limits after April 16, 2016

Unit	**NO_X BART Emission Limit**	**BART Technology**
Northeastern Unit 3	0.15 lb/mmBtu (30-day average)	Combustion controls including LNB/OFA
Northeastern Unit 4		Shut down by April 16, 2016
Unit	**SO_2 BART Emission Limit**	**BART Technology**
Northeastern Unit 3	0.40 lb/mmBtu (30-day average)	Dry Sorbent Injection
Northeastern Unit 4		Shut down by April 16, 2016

VI. FURTHER REASONABLE PROGRESS

The settlement agreement also provides for decreased capacity utilization in the remaining coal-fired unit over its shortened lifetime. Under this agreement, AEP/PSO will shut down the remaining coal-fired unit by December 31, 2026. The visibility impact from the settlement agreement will be zero after 2026. By adopting the decreased capacity utilization limits and adopting the early shutdown schedule, DEQ expects the cumulative SO_2 and NO_X emissions from Northeastern Units 3 and 4 to be approximately 36% of the emissions that could be emitted under the FIP scenario.

Table 15: SO_2 and NO_X Emissions with Further Reasonable Progress

	Unit 3 and Unit 4	
	SO_2	NO_X
BART (FIP Scenario) (30yrs from January 2017)	75,292 Tons	188,231 Tons
Settlement Agreement from April 16, 2016 – December 31, 2026	69,516 Tons	26,068 Tons

Note that under the FIP scenario, AEP/PSO would be authorized to emit an additional approximately 26,700 tons (not included in the table) of SO_2 in the 8½ months between the settlement agreement deadline and the January 2017 FIP deadline to begin operating with BART controls.

VII. 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 must comply with the permitting requirements of Subchapter 8 as they apply to the installation of controls determined to meet BART on the schedule outlined in the settlement agreement.

The installation of controls determined to meet BART will not change NSPS or NESHAP/MACT applicability for the gas-fired units at the Northeastern Power Station.

VIII. OPERATING PERMIT

The Northeastern Power Plant is a major source under OAC 252:100-8 and must submit an application to modify their existing Title V permit to incorporate the requirements to install controls determined to meet BART on the schedule outlined in the settlement agreement.