GARY L. SHERRER
SECRETARY OF ENVIRONMENT

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MARY FALLIN
GOVERNOR

STATE OF OKLAHOMA
OFFICE OF THE
SECRETARY OF ENVIRONMENT
www.environment.ok.gov

June 14, 2013

Mr. Ron Curry, Regional Administrator (6RA)
U.S. Environmental Protection Agency – Region VI
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

Subject: Oklahoma Regional Haze State Implementation Plan ("SIP") Revision Including Revisions to Affected Portions of the Interstate Transport SIP for 1997 8-Hour Ozone and 1997 $PM_{2.5}$ NAAQS

Dear Mr. Curry:

In a letter to your predecessor dated March 30, 2011, Governor Mary Fallin appointed me as her designee for the purpose of submitting documents to the U.S. Environmental Protection Agency (EPA) for approval and incorporation into the State Implementation Plan ("SIP") for the State of Oklahoma. The Oklahoma Department of Environmental Quality ("DEQ") is given the primary responsibility and authority to prepare and implement the state's air quality management plan under the Oklahoma Statutes.

Accordingly, the State of Oklahoma submits for your review under §§110 and 169A of the federal Clean Air Act and 40 CFR Part 51, a revision of the Oklahoma Regional Haze State Implementation Plan, submitted in February 2010, and the associated evidence as required by 40 CFR 51, Appendix V, 2.1. This revision of the Regional Haze SIP addresses EPA's regional haze regulations, 40 CFR § 51.308, as they relate to the BART determination for American Electric Power/Public Service Company of Oklahoma ("AEP/PSO") Northeastern Power Station Units 3 & 4. Also, this SIP revision includes revisions to affected portions of the Interstate Transport SIP for the 1997 8-hour Ozone and 1997 $PM_{2.5}$ NAAQS, submitted in May 2007 (including supplemental information submitted in November 2007), and is intended to replace the related EPA-issued FIP as it relates to the subject facility.

In a letter dated March 20, 2013, parallel processing of this submittal in accordance with the EPA guidance in Janet McCabe's October 31, 2011 Memorandum (Subject: Options and Efficiency Tools for EPA Action on State Implementation Plan Submittals) was requested. DEQ conducted a public hearing regarding the SIP revision on May 20, 2013. While there were minor wording changes to address comments received during the comment period, no substantive changes were made to the proposed SIP revision.

As required by 40 CFR § 51.103(a) and regional guidance, included with this letter are two paper copies and an identical electronic copy (on CD) of the submittal. Electronic access to the submittal is also currently available via a link on the DEQ Regional Haze webpage at:

http://www.deq.state.ok.us/aqdnew/RulesAndPlanning/Regional_Haze_rev2013

Mr. Ron Curry
U.S. EPA – Region VI
June 14, 2013

If you have questions, please contact me or Eddie Terrill, Director of DEQ's Air Quality Division, at (405) 702-4154.

Sincerely

Gary Sherrer
Secretary of Environment
Enclosures

cc: Steve Thompson, Executive Director, Department of Environmental Quality
Eddie Terrill, Director, DEQ Air Quality Division
Guy Donaldson, Section Chief, Air Planning Section, EPA Region VI (6PD-L)
Jeff Robinson, Section Chief, Air Permits, EPA Region VI (6PD-R)

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O K L A H O M A
DEPARTMENT OF ENVIRONMENTAL QUALITY

STEVEN A. THOMPSON
Executive Director

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

MARY FALLIN
Governor

June 14, 2013

Mr. Ron Curry, Regional Administrator (6RA)
U.S. Environmental Protection Agency – Region VI
1445 Ross Ave., Suite 1200
Dallas, TX 75202-2733

Subject: Certification of May 20, 2013 Hearing
Regional Haze State Implementation Plan (SIP) and Interstate Transport SIP for 1997 8-Hour Ozone and 1995 PM2.5 NAAQS Revision

Dear Mr. Curry:

The Oklahoma Department of Environmental Quality ("DEQ") recently conducted a public hearing concerning a proposed Revision to the Regional Haze State Implementation Plan (SIP) *Including Revisions to the Affected Portions of the* Interstate Transport SIP for the 1997 8-Hour Ozone and 1997 $PM_{2.5}$ NAAQS. The public hearing was held on May 20, 2013 from 1:00 to 3:00 p.m. in the 1st Floor Multipurpose Room of the DEQ headquarters, 707 North Robinson Ave., Oklahoma City, Oklahoma, 73102.

On behalf of DEQ, I certify that the hearing was conducted in accordance with the information provided in the public notice and requirements of the laws and constitution of the State of Oklahoma and 40 C.F.R. § 51.102.

Sincerely,

Eddie Terrill
Division Director
Air Quality Division

ET:CB

Regional Haze Implementation Plan Revision

[Including Revisions to Affected Portions of the Interstate Transport SIP for the 1997 8-hour Ozone and 1997 $PM_{2.5}$ NAAQS]

State of Oklahoma

Department of Environmental Quality

June 14, 2013

Table of Contents

List of Tables

List of Appendices

I. Background

A. Regional Haze SIP

Oklahoma submitted its Regional Haze Implementation Plan Revision ("Regional Haze SIP" or "RH SIP") in February 2010. The U.S. Environmental Protection Agency ("EPA") approved core elements of the Regional Haze SIP effective January 27, 2012 (76 Fed.Reg. 81727, Dec. 28, 2011), codified at 40 C.F.R. § 52.1920). In the same action, EPA approved Oklahoma's Best Available Retrofit Technology ("BART") determinations for the majority of emissions units subject to BART, but disapproved the sulfur dioxide ("SO_2") BART determinations for several emissions units (40 C.F.R. § 52.1928), and issued a Federal Implementation Plan ("FIP") covering those units (40 C.F.R. § 52.1923). As part of this action, EPA also disapproved the State's submitted Regional Haze Long Term Strategy because it relied in part on the BART limits in the disapproved determinations. Specifically, EPA disapproved the SO_2 BART determinations for Units 3 and 4 of the American Electric Power/Public Service Company of Oklahoma ("AEP/PSO") Northeastern Power Station in Rogers County ("Northeastern Units 3 and 4"), including Section VI(E), "Greater Reasonable Progress Alternative Determination" and the associated PSO Regional Haze Agreement, Case No. 10-025. The final action approved the Oklahoma Regional Haze SIP's SO_2, oxides of nitrogen ("NO_X"), and particulate matter ("PM") BART determinations for the AEP/PSO Northeastern Unit 2, and the NO_X and PM BART determination for the AEP/PSO Northeastern Units 3 and 4.

Subsequent to publishing the final FIP, AEP/PSO, DEQ, EPA, and the U.S. Department of Justice entered discussions on alternatives to the FIP requirements that would provide the necessary visibility improvements. Notice of the resulting proposed settlement agreement was published in the Federal Register on November 14, 2012.[1] The final settlement agreement outlines a strategy for AEP/PSO to meet its obligations under the visibility provisions of the Federal Clean Air Act. The final settlement agreement became effective with the signature of a U.S. Department of Justice representative on February 8, 2013.

With this submittal, the State of Oklahoma is revising those portions of its Regional Haze SIP that relate to the SO_2 and NO_X BART determinations for AEP/PSO's Northeastern Units 3 and 4. This revision of the Regional Haze SIP addresses the requirements of the visibility provisions of the Federal Clean Air Act, 42 U.S.C. § 7491, and EPA's regional haze regulations, 40 C.F.R. § 51.308, as they relate to AEP/PSO's Northeastern Units 3 and 4. Moreover, this revision is intended to obviate the need for and replace the corresponding EPA-issued FIP as it relates to Northeastern Units 3 and 4. Specifically, the revision is intended to result in the removal of all references to Northeastern Units 3 and 4 in 40 C.F.R. §§ 52.1923 and 52.1928.

B. Interstate Transport SIP

Oklahoma submitted its *Interstate Transport SIP for an Assessment of Oklahoma's Impact on Downwind Nonattainment for the National Ambient 8-hour Ozone and $PM_{2.5}$ Air Quality Standards*

[1] 77 Fed.Reg. 67814 (Nov. 14, 2012). The Settlement Agreement (Appendix I) for Public Service Company of Oklahoma's ("PSO's") Petition for Review was entered into by PSO, the Oklahoma Secretary of the Environment, DEQ, EPA, and the Sierra Club .

("Transport SIP") to EPA in May 2007 (including supplemental information submitted in November 2007). EPA has taken several actions, codified at 40 C.F.R. § 52.1920, to give partial approval/disapproval of the Transport SIP as it addresses various aspects of the required elements of § 110(a)(2)(D) of the Federal Clean Air Act, 42 U.S.C. § 7410(a)(2(D). *See* 75 Fed.Reg. 72701 (Nov. 26, 2010); 76 Fed.Reg. 81838 (Dec. 29, 2011); and 77 Fed.Reg. 3933 (Jan. 26, 2011). EPA's 2011 action on Oklahoma's Regional Haze SIP also addressed interstate transport of pollutants and visibility protection as follows:

> We are partially approving and partially disapproving a portion of a SIP revision we received from the State of Oklahoma on May 10, 2007, as supplemented on December 10, 2007, for the purpose of addressing the 'good neighbor' provisions of the CAA section 110(a)(2)(D)(i) with respect to visibility for the 1997 8-hour ozone NAAQS and the $PM_{2.5}$ NAAQS.
>
> . . .
>
> We are finalizing a FIP to address the requirements of section 110(a)(2)(D)(i)(II) with respect to visibility to ensure that emissions from sources in Oklahoma do not interfere with the visibility programs of other states. We find that the controls under this FIP, in combination with the controls required by the portion of the Oklahoma RH submittal that we are approving, will serve to prevent sources in Oklahoma from emitting pollutants in amounts that will interfere with efforts to protect visibility in other states.

76 Fed.Reg. 81757 (Dec. 28, 2011). This SIP revision addresses the requirements of the interstate transport provisions of the Federal Clean Air Act, 42 U.S.C. 7410(a)(2)(D)(i)(II) as they relate to AEP/PSO's Northeastern Units 3 and 4. Moreover, this revision is intended to obviate the need for and replace the corresponding EPA-issued FIP as it relates to Northeastern Units 3 and 4. Specifically, the revision is intended to result in the removal of all references to Northeastern Units 3 and 4 in 40 C.F.R. §§ 52.1923 and 52.1928.

II. Revised Best Available Retrofit Technology for AEP/PSO Northeastern Units 3 and 4

A. Source Description

AEP/PSO Northeastern Power Station is located in Rogers County, Oklahoma. The station includes one (1) 495 MW gas-fired steam electric generating unit designated as Northeastern Unit 2 and two (2) 490 MW coal-fired steam electric generating units designated as Northeastern Units 3 and 4. Note that EPA approved the BART determination for Northeastern Unit 2 and the portion of the BART determination not related to SO_2 for Northeastern Units 3 and 4. *See* 76 Fed.Reg. 81727 (Dec. 28, 2011). The facility is currently permitted to operate under DEQ Air Quality Permit No. 2003-410-TVR (M-3), which was issued on March 8, 2012.

B. Determination of BART Requirements

Oklahoma's original Regional Haze SIP documented how DEQ conducted a case-by-case five-factor BART analysis for each of the BART-subject units. Based on information and cost estimates provided by the affected facilities at that time, DEQ determined that Dry Flue Gas Desulfurization with Spray Dryer Absorber ("DFGD/SDA") was not cost-effective for SO_2 control for PSO Northeastern Units 3 and 4. The determination also included additional compliance options, including a Greater Reasonable Progress Alternative Determination. In its disapproval, EPA disagreed with DEQ's application of the costing methodologies, and consequently issued a FIP with emission limits that assumed application of DFGD/SDA technology.

On November 20, 2012, AEP/PSO submitted to DEQ the Supplemental BART Determination Information, which proposed a revised BART as part of AEP/PSO's long-term multi-media, multi-pollutant plan. The BART determination for AEP/PSO Northeastern Units 3 and 4 has been revised based on this information. The Revised BART Determination, attached as Appendix II, provides that the facility will install and operate a dry sorbent injection ("DSI") system on one of the units (either Unit 3 or 4) to meet an SO_2 emission standard of 0.40 lb/mmBTU or less by April 16, 2016. This determination relies on voluntary emission reductions provided in the Supplemental BART Determination Information, including retirement of one of the affected units by April 16, 2016.

Table II-1 reflects actual emissions from baseline (2004 – 2006) operations. These emissions were used in the evaluations of cost effectiveness to provide bases for realistic estimates of the emissions controlled (or removed) through the implementation of BART and additional voluntary measures. Table II-2 summarizes the future potential emissons of Units 3 and 4 after application of the BART control technologies, emission limits, and additional voluntary measures. The data in this table reflects future potential emissions rather than projected actual emissions as the estimates are based on full capacity utilization. DEQ entered into an enforceable administrative order with AEP/PSO for Northeastern Units 3 and 4 (attached as Appendix III[2]) requiring the installation and operation of BART, the achievement of the associated BART emission limitations, and specific voluntary measures related to early implementation of reduced SO_2 and NO_X emission rates, unit retirements and capacity restrictions. The administrative order requires AEP/PSO to obtain necessary permit modifications that will also include a requirement, schedule, and procedures to ensure that the source properly installs, operates, monitors, and maintains any required control equipment. Therefore, the emission rates in this table are enforceable through the First Amended Regional Haze Agreement and will be incorporated into subsequent permits. [For simplicity, the table reflects AEP/PSO's indication that Unit 4 is the likely unit to be shut down in 2016, but there is no requirement as to which of the two units is shut down first.]

Table II-1: Baseline control technologies and emissions for AEP/PSO Northeastern Units 3 and 4

Baseline Emissions			
		Unit 3	**Unit 4**
Design Heat Input to Boiler		4,775 mmBtu/hr	4,775 mmBtu/hr
SO_2	Control	Low-Sulfur Coal	Low-Sulfur Coal
	Emission Rate (lb/mmBtu)	0.9 lb/mmBtu	0.9 lb/mmBtu
	Combined Annual Emission Rate[1]	31,999 TPY	

[2] Appendix III contains the First Amended Regional Haze Agreement, Case No. 10-025, which amends and updates the PSO Regional Haze Agreement, Case No. 10-025, attached as Item 2 in Appendix 6-5 of the original Regional Haze SIP submittal.

NO_X	Control	1st Generation LNB w/ OFA[2]	1st Generation LNB w/ OFA[2]
	Emission Rate (lb/mmBtu)	0.40 lb/mmBtu	0.40 lb/mmBtu
	Combined Annual Emission Rate[1]	14,222 TPY	
PM_{10}	Control	Electrostatic precipitator	Electrostatic precipitator
	Emission Rate (lb/mmBtu)	0.10 lb/mmBtu	0.10 lb/mmBtu
	Combined Annual Emission Rate[1]	3,555 TPY	

[1]85% Capacity Factor and lb/mmBtu emission rates developed from 2004-2006 annual average operating data.
[2]LNB = Low NOx Burners
OFA = Over-fired Air

Table II-2: Implementation of BART control technologies and emission limits for AEP/PSO Northeastern Units 3 and 4

Preliminary/BART Control Steps (Prior to Unit 4 Shutdown[1])			
By December 31, 2013		**Unit 3**	**Unit 4**
NO_X	Control	LNB w/ Separated OFA[2]	LNB w/ Separated OFA[2]
	Emission Rate (lb/mmBtu)	0.23 lb/mmBtu (30-day rolling average)	0.23 lb/mmBtu (30-day rolling average)
	Hourly Emission Rate	1,098 lb/hr (30-day rolling average)	1,098 lb/hr (30-day rolling average)
	Combined Annual Emission Rate	9,620 TPY (12-month rolling)	
By January 31, 2014		**Unit 3**	**Unit 4**
SO_2	Control	Low Sulfur Coal	Low Sulfur Coal
	Emission Rate (lb/mmBtu)	0.65 lb/mmBtu[3] (30-day rolling average)	0.65 lb/mmBtu (30-day rolling average)
	Hourly Emission Rate	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)
	Combined Annual Emission Rate	25,097 TPY (12-month rolling)	
BART Control (with Unit 4 Shutdown[1])			
By April 16, 2016		**Unit 3[1]**	
SO_2	Control	Dry Sorbent Injection (DSI) with Activated Carbon Injection	
	Emission Rate (lb/mmBtu)	0.4 lb/mmBtu (30-day rolling average)	
	Hourly Emission Rate	1,910 lb/hr (30-day rolling average)	
	Annual Emission Rate	8,366 TPY	
NO_X	Control	LNB w/ Separated OFA (and Further Control System Tuning)	
	Emission Rate (lb/mmBtu)	0.15 lb/mmBtu (30-day rolling average)	
	Hourly Emission Rate	716 lb/hr (30-day rolling average)	
	Annual Emission Rate	3,137 TPY	

[1]For simplicity, the table reflects AEP/PSO's indication that Unit 4 is the likely unit to be shut down in 2016, but there is no requirement as to which of the two units is shut down first.
[2]LNB = Low NOx Burners
OFA = Over-fired Air
[3]An alternative operating scenario is provided in paragraph 12 of the First Amended Regional Haze Agreement, Case No. 10-025, that addresses potential disruption of coal supplies during the time period from January 31, 2014 through April 16, 2016.

The application of BART to AEP/PSO Northeastern Units 3 and 4 provides an estimated emission reduction of 24,888 tons of SO_2 per year from the baseline beginning in 2016, based on projection of the historically representative 85% capacity utilization through 2020. Table II-3 shows these BART reductions, as well as estimated NO_X emission reductions for the same timeframe.

Table II-3: BART-Level emissions reductions from the baseline, AEP/PSO Northeastern Units 3 and 4

	Baseline Emissions (Units 3 and 4 Combined)		BART Emissions (Beginning 4/16/2016 - Unit 3 Only)		Emission Reductions (Beginning 4/16/2016)
	lb/MMBTU	TPY	lb/MMBTU	TPY	TPY
SO_2	0.9	31,999	0.4	7,111	24,888
NO_X	0.40	14,222	0.15	2,667	11,555

Table II-4 indicates the baseline and anticipated improvement in visibility at mandatory federal Class I areas due to the shutdown of a unit and the installation of SO_2 and NO_X controls (DSI and LNB w/OFA, respectively) on the remaining unit at AEP/PSO Northeastern, calculated as the 3-year average of the 98th percentile modeled visibility impairment.

Table II-4: Class I Areas Baseline and Visibility improvement with BART controls

Contribution to Visibility Impairment for each Class I Area				
	Wichita Mountains (Δ-dv)	Caney Creek (Δ-dv)	Upper Buffalo (Δ-dv)	Hercules Glade (Δ-dv)
Baseline Impairment	1.501	1.627	1.169	1.112
SO_2 Control (NO_X Baseline)	0.464	0.553	0.402	0.332
NO_X and SO_2 Control	0.295	0.294	0.216	0.209
Percent Improvement (Reduction)	80%	82%	82%	81%

III. Further Reasonable Progress and Amended Long-term Strategy with Emission Reduction

The long-term strategy described in Chapter VII of Oklahoma's original Regional Haze SIP submittal addresses visibility impairment at the Wichita Mountains Class I area, and covers the period through 2018 in fulfillment of 40 C.F.R. § 51.308(d)(3). The long-term strategy includes issuance and enforcement of permits limiting emissions from major and minor sources in Oklahoma, state rules which specifically limit targeted emissions sources and categories, and several other ongoing air pollution control programs.

The emissions limitations and other requirements necessary to implement the BART requirements for AEP/PSO's Northeastern Units 3 and 4 will be incorporated into required DEQ Air

Quality Permit(s), as discussed herein. AEP/PSO's Supplemental BART Determination Information and the First Amended Regional Haze Agreement also provide for further reasonable progress through a schedule of NO_X emissions reductions earlier than the schedule in the previously-approved portion of the Regional Haze SIP, as listed in Table II-2. In addition, the agreement provides for incremental decreases in capacity utilization between January 1, 2021 and December 31, 2026, when the remaining unit will be shut down, with the corresponding reduced emissions listed in Table III-1.

Table III-1: Further Reductions

Further Reasonable Progress over Remaining Unit Life – Unit 3 Emissions during Incremental Decrease in Capacity Utilization		
	SO_2	**NO_X**
January 1, 2021 – 70% Utilization	5,856 TPY	2,196 TPY
January 1, 2023 – 60% Utilization	5,019 TPY	1,882 TPY
January 1, 2025 - 50% Utilization	4,183 TPY	1,569 TPY
December 31, 2026	Unit Shutdown	

The First Amended Regional Haze Agreement ultimately provides for Further Reasonable Progress through the reduction of 31,999 tons of SO_2 per year from the baseline following shutdown of the remaining unit after 2026. Table III-2 shows these reductions from the baseline, as well as estimated NO_X emission reductions, based on the planned incremental decrease in capacity utilization for Unit 3 between 2021 and 2026.

Table III-2: Further Reasonable Progress emissions reductions from the baseline

Further Reasonable Progress Reductions over Remaining Unit Life		
	SO_2	**NO_X**
January 1, 2021 – 70% Utilization	26,143 TPY	12,026 TPY
January 1, 2023 – 60% Utilization	26,980 TPY	12,340 TPY
January 1, 2025 - 50% Utilization	27,816 TPY	12,653 TPY
December 31, 2026 (Both Units Shut Down)	31,999 TPY	14,222 TPY

As required by subparagraph 26(E) of the First Amended Regional Haze Agreement, AEP/PSO will develop and propose a monitoring program to test various operating profiles and other measures required under subparagraph 26(D) to determine whether increased SO_2 removal efficiencies can be achieved during normal operations. The monitoring program will be developed and proposed during the first year of operation of the required controls. AEP/PSO will submit the monitoring program to EPA and ODEQ for review, and will implement the monitoring program during the second and third years of operation of the DSI system. AEP/PSO will evaluate and report the results of the monitoring program to EPA and ODEQ. If the evaluation demonstrates that the technology is capable of sustainably achieving an emission rate of less than 0.37 lb/MMBtu on a 30-day rolling average basis without: (1) altering the unit's fuel supply; (2) incurring additional capital costs; (3) increasing operating expenses by more than a negligible amount; and/or (4) adversely impacting overall unit operations, the emission rate will be adjusted by 60% of the difference between 0.40 lb/MMBtu and the demonstrated emission rate. If the demonstrated emission rate is 0.37 lb/MMbtu or greater, no adjustment will be made and the emission rate from the remaining unit will remain at 0.40 lb/MMBtu.

If the SO_2 emission rate for the remaining coal-fired unit (Northeastern Unit 3) is not reduced to 0.30 lb/mmBtu after the implementation of the control requirements set forth in this revision and the incorporated First Amended Regional Haze Agreement, then DEQ commits to obtain and/or identify additional SO_2 reductions within the State of Oklahoma to the extent necessary to achieve the anticipated visibility benefits estimated in the CENRAP Base G 2018 regional haze modeling and attributable to reductions in SO_2 emissions after installation of presumptive controls on AEP/PSO Northeastern Units 3 and 4. Any additional SO_2 emissions reductions obtained and/or identified from the northeast quadrant of the State will be presumed to count toward the mass emission reductions necessary to achieve the anticipated visibility benefits. Emissions reductions obtained outside the northeast quadrant that are technically justified will also be counted. If necessary, additional emission reductions shall be obtained via enforceable emission limits or control equipment requirements made enforceable through administrative orders, permits, and/or rulemaking actions. Any additional SO_2 reductions will be obtained and/or identified and a corresponding SIP revision will be submitted to EPA as expeditiously as practicable, but in no event later than the end of the first full Oklahoma legislative session occurring subsequent to AEP/PSO's submission of the evaluation and report required by Paragraph 1(f) of Attachment A to the Settlement Agreement. Moreover, any additional reductions that are obtained prior to the 2018 Regional Haze SIP revision required by 40 C.F.R. § 51.308(f) but not accounted for in the above referenced modeling will be identified in the 2018 revision.

In calendar year 2021, as required by subparagraph 26(G) of the First Amended Regional Haze Agreement, AEP/PSO will evaluate whether the projected generation from the remaining unit can be replaced at lower or equal total projected cost from natural gas or renewable resources. If power is available from such resources at a lower projected total cost (including consideration of AEP/PSO's need to recover its remaining investment in the remaining unit), then the operating unit will be shut down no later than December 31, 2025.

Additional Federal measures, which affect emissions that impact visibility, have been promulgated, proposed, and/or planned since submission of Oklahoma's original Region Haze SIP submission. These additional measures include the Mercury and Air Toxics Standard ("MATS"), as well as other new or revised NESHAPs and NSPS. In addition, visibility improvements are likely to result from implementation of NAAQS revisions, particularly the 2010 SO_2 NAAQS. Reductions in SO_2 and NO_x emissions from other states required under the Clean Air Interstate Rule ("CAIR") and its successor program will and must remain a critical part of Oklahoma's long-term visibility strategy. Future reviews of the Regional Haze SIP will likely provide a clearer evaluation of the effects of the Federal measures on visibility in Class I areas that are currently impacted by Oklahoma sources.

IV. Interstate Transport SIP

Implementation of (1) the revised BART for AEP/PSO Northeastern Units 3 and 4; (2) the First Amended Regional Haze Agreement, Case No. 10-025; and (3) the additional reductions described in Section III, will result in reductions in the amount of Oklahoma emissions that are available for interstate transport. Together, these reductions will address the disapproved portions of the Transport SIP as it relates to AEP/PSO Northeastern Units 3 and 4.

V. Review, Consultations, and Comments

A. EPA Review with Parallel Processing

The State of Oklahoma submitted the proposed Regional Haze SIP Revision, in electronic and paper form, for EPA review on March 20, 2013, along with a request for parallel processing. At that time, the State also submitted a copy of the draft notice of public hearing and opportunity for comment, prepared in accordance with 40 C.F.R. § 51.102 and "Procedures for Notice of Opportunity for Public Hearing and Comment – Oklahoma SIP Review/Revision Submittals." These state public participation procedures were submitted to EPA for review under 40 CFR § 51.102. In a letter dated August 23, 2012, EPA concurred that they are consistent with the requirements of 40 CFR § 51.102 and associated guidance.

B. Federal Land Manager Consultation

As part of the development of this implementation plan revision, DEQ consulted with the designated Federal Land Manager (FLM) staff personnel in accordance with the provisions of 40 C.F.R. § 51.308(i)(2). DEQ provided an opportunity to federal land managers for consultation in person and at least 60 days before holding any public hearing on this implementation plan revision. This consultation gave the federal land managers the opportunity to discuss their assessment of:

- Impairment of visibility at the Wichita Mountains and at other Class I areas;
- Recommendations on the development of reasonable progress goals; and
- Recommendations on strategies to address visibility impairment.

On March 20, 2013, simultaneous with submittal of the request to EPA for parallel processing, DEQ notified the federal land manager staff of this proposed Regional Haze SIP Revision, and provided them with electronic access to the revision and related documents. DEQ also provided the federal land manager staff with notice of the public hearing scheduled for May 20, 2013. Comments received from the FLMs have been considered and posted on the DEQ Regional Haze webpage. The FLM Contact List and comments, are included in Appendix V. Responses to the FLM comments are included in the Summary of Comments and Responses document in Appendix VII.

C. Consultation with States

Oklahoma conducted an extensive consultation process with states with Class I Areas whose visibility are potentially affected by Oklahoma emissions during the original Regional Haze SIP development and submittal process. On March 20, 2013, simultaneous with submittal of the request to EPA for parallel processing, DEQ notified the appropriate clean air agency staff for bordering/potentially affected states (Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Nebraska, New Mexico, and Texas) of this proposed Regional Haze SIP Revision, and provided them with electronic access to the revision and related documents. DEQ will also notified the state agency staff of the public hearing scheduled for May 20, 2013. No comments were received from the state agency staff. The State Contact List is included in Appendix V.

D. Public Comment Period and Hearing

DEQ provided notice of a public hearing and opportunity to comment on the proposed Regional Haze SIP Revision at least 30 days in advance of the scheduled public hearing, as required by 40 C.F.R. § 51.102. DEQ held a public hearing regarding the implementation plan revision on May 20, 2013 at the DEQ offices in Oklahoma City, Oklahoma. Notice was posted on the DEQ Regional Haze webpage beginning on April 19, 2013. Notice was also published in the Tulsa World on April 18, 2013, and in the Oklahoman and the Lawton Constitution on April 19, 2013 (i.e., in at least one newspaper of general circulation at least 30 days before the hearing), and was provided via e-mail to those persons who have expressed an interest in SIP revisions and have supplied their e-mail addresses and via regular mail to those persons who have expressed an interest in SIP revisions and have supplied their mailing addresses.

The notice included information on the availability of the proposed Regional Haze SIP Revision for public inspection at 707 N. Robinson Ave, Oklahoma City, OK, and through the DEQ Regional Haze webpage: http://www.deq.state.ok.us/aqdnew/RulesAndPlanning/Regional_Haze

Both written and oral comments were received by DEQ from the public. Electronic copies of the written comments have been posted on the DEQ Regional Haze web site, along with a copy of the hearing transcript. Copies of written comments received are included in Appendix V, and DEQ's Summary of Comments and Responses document is included in Appendix VII. Appendix IV contains copies of the notice and notice certification, and Appendix VI contains copies of the hearing transcript, sign-in sheet(s) and hearing certification.

Appendices

Appendix I

AEP/PSO Settlement Agreement

SETTLEMENT AGREEMENT

This Settlement Agreement ("Agreement") is entered into by Public Service Company of Oklahoma ("PSO"), the Secretary of the Environment on behalf of the State of Oklahoma ("Secretary"), the Oklahoma Department of Environmental Quality ("ODEQ"), the United States Environmental Protection Agency ("EPA"), and the Sierra Club. PSO, the Secretary, ODEQ, EPA, and the Sierra Club are hereinafter collectively referred to as "the Parties" for purposes of this Agreement.

RECITALS

A. On December 28, 2011, EPA issued a final rule entitled, "Approval and Promulgation of Implementation Plans; Oklahoma; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Best Available Retrofit Technology Determinations," 76 Fed. Reg. 81,728 (Dec. 28, 2011) (the "Final Rule").

B. The Final Rule partially approved and partially disapproved Oklahoma's state implementation plan ("SIP") submitted under the "visibility" and "interstate transport" provisions of the Clean Air Act ("CAA"), 42 U.S.C. § 7410, 7491, and 7492. The Final Rule included a federal implementation plan ("FIP") establishing Best Available Retrofit Technology ("BART") emission limitations on sulfur dioxide ("SO_2") for Units 3 and 4 of PSO's Northeastern plant ("PSO's Units") to address the visibility and interstate transport provisions of the CAA.

C. PSO desires to develop and implement a comprehensive strategy to comply with its obligations with respect to the visibility and interstate transport provisions of the CAA as well as its other obligations with respect to the CAA in a coordinated manner.

D. PSO intends to install low NOx combustion technologies on both of its Units, retire one of its Units, and install and operate on its other Unit a dry sorbent injection system and baghouse in order to achieve emissions rates that comply with the terms of this Agreement and with its obligations with respect to the visibility provisions of the CAA.

E. PSO intends to retire one of its Units and install and operate on its other Unit a dry sorbent injection system, a baghouse, and activated carbon injection to achieve emissions rates that comply with the Mercury & Air Toxics Standard that became effective April 16, 2012, 40 C.F.R. § 63.9984 ("the MATS Rule"). Properly designed and operated air pollution control systems consisting of dry sorbent injection system, baghouse, and activated carbon injection can achieve the MATS Rule emission limits. An EPA letter to the ODEQ and PSO dated July 18, 2012, expresses EPA's support of PSO's comprehensive strategy to use the technologies described in the Regional Haze Agreement referenced in Attachment A to this Agreement to achieve the emission limitations prescribed by the MATS Rule. The letter is attached to this Agreement as Attachment B.

F. On February 24, 2011, PSO timely filed a Petition for Review, challenging the issuance of the Final Rule in *Public Service Company of Oklahoma v. U.S. Environmental Protection Agency, et al.*, No. 12-9524. On March 26, 2012, Sierra Club filed a timely motion to intervene. The motion was granted March 27, 2012.

G. The CAA and EPA's regulations require States to develop SIPs to implement the CAA's provisions, including the CAA's visibility and interstate transport provisions. *See* 42 U.S.C. §§ 7410(a)(2)(D)(i)(II), (J), 7491(b)(2); 40 C.F.R. § 50.300(a). ODEQ is the administrative agency in the State of Oklahoma responsible for developing and proposing such SIPs. *See* 27A O.S. §§ 2-5-105(3), (20), 1-3-101(B)(8), 2-3-101(B)(2). The Secretary, as the Governor's designee for the State of Oklahoma, is responsible for submitting SIPs to EPA for review. *See* 40 C.F.R. Part 51, Appendix V, Section 2.1(a); 40 C.F.R. § 51.103(a). Because this Agreement requires ODEQ to develop and propose and the Secretary to submit SIP revisions to EPA under the visibility and interstate transport provisions of the CAA, and ODEQ and the Secretary prefer to regulate PSO under such SIP revisions rather than EPA's FIP, ODEQ and the Secretary have an interest in and are essential parties to this Settlement Agreement.

H. The Parties have negotiated in good faith and have determined that the settlement reflected in this Agreement is in the public interest. If approved and implemented as set forth herein, this Agreement will resolve PSO's Petition for Review.

I. This Agreement will not impact any other provisions of the Final Rule, and/or any other applicable federal, state, and local laws and regulations. No other claims will be affected by the resolution of the issues related to PSO's Units as set forth herein.

AGREEMENT

1. PSO, Sierra Club, and EPA agree that within ten (10) days after this Agreement is executed by the Parties (i.e., signed), but before finalization pursuant to Paragraph 16 of this Agreement, they will jointly move the Court for an order holding in abeyance PSO's Petition for Review pending implementation of the terms of the Agreement.

2. Within thirty (30) days of the effective date of this Agreement, PSO shall submit to ODEQ final and complete versions of all information and documentation (including technical supporting documentation for PSO's Units) necessary for the development of the SIP revisions referenced in Paragraphs 3 and 4.

3. No later than one hundred-twenty (120) days after PSO provides ODEQ with the information and documentation required in Paragraph 2, ODEQ will develop and propose a SIP revision under the visibility provisions of the CAA, 42 U.S.C. § 7491, and EPA's regional haze regulations, 40 C.F.R. § 51.308, that addresses PSO's Units ("Regional Haze SIP revision") in accordance with the provisions of Attachment A.

4. No later than one hundred-twenty (120) days after PSO provides ODEQ with the information and documentation required in Paragraph 2, ODEQ will develop and propose

a SIP revision under the interstate transport provisions of the CAA, 42 U.S.C. § 7410(a)(2)(D)(i)(II), that addresses PSO's Units ("Interstate Transport SIP revision") in accordance with the provisions of Attachment A.

5. No later than one hundred-twenty (120) days after PSO provides ODEQ with the information and documentation required in Paragraph 2, the Secretary shall provide the proposed SIP revisions required in Paragraphs 3 and 4 to EPA and request parallel processing of the SIP revisions from EPA pursuant to 40 C.F.R. Part 51, App. V, Section 2.3.

6. If ODEQ determines, at any time subsequent to PSO's submittal of all information and documentation for PSO's Units as required in Paragraph 2, that additional information and/or documentation is necessary in order to develop the SIP revisions referenced in Paragraphs 3 and 4, ODEQ shall provide PSO with a written request for such additional information and/or documentation with a copy to all Parties. The deadlines associated with the obligations under Paragraphs 3-5 of this Agreement shall be tolled during the period of time between the issuance of the written request and ODEQ's receipt of the requested information and/or documentation.

7. After the opportunity for public hearing and the close of Oklahoma's notice-and-comment period for the Regional Haze and Interstate Transport SIP revisions, but no later than ninety (90) days after the Secretary submits the request for parallel processing referenced in Paragraph 5, ODEQ will consider and if appropriate adopt the Regional Haze and Interstate Transport SIP revisions referred to in Paragraphs 3 and 4. If adopted, the Secretary will submit to EPA those SIP revisions.

8. The Regional Haze and Interstate Transport SIP revisions adopted and submitted to EPA under Paragraph 7 will include the provisions described in Attachment A to this Agreement unless the Parties, by written mutual agreement, amend the provisions described in Attachment A. If the Regional Haze and Interstate Transport SIP revisions adopted and submitted to EPA by the Secretary do not include the provisions described in Attachment A to this Agreement, PSO may file a motion to dissolve the stay of PSO's petition for review and request that a briefing schedule be set. PSO may also pursue any opportunities for administrative or judicial review of the Regional Haze and Interstate Transport SIP revisions adopted by ODEQ and submitted by the Secretary.

9. Within sixty (60) days of EPA's receipt of the final Regional Haze and Interstate Transport SIP revisions EPA will determine whether the revisions meet the requirements of the CAA consistent with 42 U.S.C. § 7410(k)(1)(B) ("completeness finding").

10. EPA will take final action on the Regional Haze and the Interstate Transport SIP revisions as soon as possible, but no later than six (6) months from the date of the completeness finding referred to in Paragraph 9 consistent with 42 U.S.C. § 7410(k)(2).

11. If EPA promulgates a final action approving the provisions of the Regional Haze and Interstate Transport SIP revisions included in Attachment A, as adopted and submitted to

EPA by Oklahoma, PSO, the Sierra Club, and EPA will promptly file a joint stipulation of dismissal of PSO's Petition for Review. The Parties agree that they will not challenge that portion of any final action issued by EPA that fully approves the Regional Haze and Interstate Transport SIP revisions as adopted and submitted to EPA by the Secretary that contain the provisions in Attachment A affecting PSO's Units.

12. Separately from the SIP process, PSO will report biannually to EPA (beginning in 2017 for the period 2015-2016, and every second year thereafter through the end of 2025 or 2026, whenever the last Northeastern unit is retired) on the energy produced by PSO's units and the sources of energy secured under PSO's long-term purchased power contracts. The initial report will include similar information for calendar years 2013-2014. Requests for proposals ("RFPs") for long-term purchase power contracts issued between 2013 and the date the reporting obligation ends will specifically seek bids for energy supplied by natural gas and renewable resources. The biannual reports will include copies of any RFPs issued during the reporting period, and a summary of the capacity or energy secured through any long-term power purchase agreements executed during the reporting period, including the unit(s) providing the purchased power, the amount of capacity or energy secured under the agreement, and the term of each agreement.

13. The Parties may, by written mutual agreement, extend the dates in Paragraphs 2-5, 7, and 9-10 by which actions must be taken to fulfill the Parties' respective obligations under this Agreement.

14. Nothing in the Regional Haze and Interstate Transport SIP revisions as adopted and submitted to EPA by Oklahoma or in this Agreement shall relieve PSO from its obligations to comply with all applicable federal, state, and local laws and regulations, including laws, regulations, and compliance deadlines that become applicable after the date of any revisions to Oklahoma's Regional Haze SIP that may be approved by EPA. Such laws and regulations include, but are not limited to, any EPA rule imposing requirements relevant to interstate transport under 42 U.S.C. § 7410(a)(2)(D) and the MATS Rule. Nothing in Oklahoma's Regional Haze SIP revision, including the BART determination for PSO's Units, should be construed to provide any relief from the emissions limits or deadlines specified in such regulations, including, but not limited to, deadlines for the installation of pollution controls required by any such regulations.

15. If EPA does not take final action approving those aspects of the Regional Haze and Interstate Transport SIP revisions that contain the provisions of Attachment A, as adopted and submitted to EPA by Oklahoma, PSO may file a motion to dissolve the stay of PSO's Petition for Review, and to request that a briefing schedule be set. EPA does not waive or limit any defense relating to such litigation. This shall be the only remedy for EPA's failure to fulfill its obligations under this Agreement. PSO and Sierra Club agree that contempt of court is not an available remedy under this Agreement.

16. The Parties agree and acknowledge that before this Agreement is final, EPA must provide notice in the Federal Register and an opportunity for public comment pursuant to CAA

section 113(g), 42 U.S.C. § 7413(g). EPA shall promptly submit said notice of this Agreement to the Federal Register after this Agreement is executed by the Parties (i.e., signed). After this Agreement has undergone an opportunity for notice and comment, the Administrator or the Attorney General, as appropriate, shall promptly consider any such written comments in determining whether to withdraw or withhold their consent to the Agreement, in accordance with section 113(g) of the CAA.
If the United States elects not to withdraw or withhold its consent to this Agreement, EPA shall provide written notice to the Parties as expeditiously as possible. This Agreement shall become final and effective on the date that EPA provides such written notice to the Parties. If EPA does not provide such written notice within sixty (60) days after the notice of the Agreement is published in the Federal Register, the sole remedy shall be the right to file a motion to dissolve the stay of the Petition for Review, and to request that a briefing schedule be set. EPA does not waive or limit any defense relating to such litigation. PSO and Sierra Club agree that contempt of court is not an available remedy under this Agreement.

17. No provision of this Agreement shall be interpreted as or constitute a commitment or requirement that the United States or any of its departments or agencies obligate or pay funds in contravention of the Anti-Deficiency Act, 31 U.S.C. § 1341 *et seq.*, or in violation of any other statue, law, or regulation.

18. Nothing in this Agreement shall be construed to limit or modify the discretion accorded to EPA, ODEQ, or the Secretary by statute, or by general principles of administrative law.

19. Nothing in this Agreement shall be construed to limit or modify the rights of PSO or Sierra Club to seek reconsideration or judicial review of any altered, amended or revised provisions of any final action that ODEQ or EPA may take that differ in any material respect from the provisions described in Attachment A (or as amended by mutual written agreement of the Parties pursuant to Paragraph 8).

20. The undersigned hereby certify that they are duly authorized to bind the Party on whose behalf this Agreement is executed to the terms of this Agreement.

21. The provisions of this Agreement shall apply to and be binding on the Parties, their successors and assigns.

22. This Agreement may be signed in counterparts, and such counterpart signatures shall be given full force and effect.

FOR PETITIONER PSO:

Dated: 10-17-12

J. Stuart Solomon

J. Stuart Solomon, President
Public Service Company of Oklahoma

FOR STATE OF OKLAHOMA:
SECRETARY OF THE ENVIRONMENT FOR
THE STATE OF OKLAHOMA

Dated: 10/1/12

Gary L Sherrer

FOR OKLAHOMA DEPARTMENT OF
ENVIRONMENTAL QUALITY:

Dated: 9-28-12

Steven A. Thompson

FOR U.S. ENVIRONMENTAL PROTECTION AGENCY:

IGNACIA S. MORENO
Assistant Attorney General
Environment and Natural Resources Division

Dated: 2/8/13

By: Stephanie J. Talbert

STEPHANIE J. TALBERT
Environmental Defense Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. BOX 7611
Washington, DC 20044
(202) 514-2617
Fax: (202) 514-8865
Stephanie.Talbert@usdoj.gov

FOR INTERVENOR SIERRA CLUB:

Dated: 10/16/12 ____________________

ATTACHMENT A

1. Oklahoma, through the Secretary, will submit to EPA a Regional Haze SIP revision that addresses PSO's Units and includes, among other things, the following elements:

    a. Oklahoma's SIP revision will include a Regional Haze Agreement ("RHA") entered into by ODEQ and PSO to effectuate the BART determination.

    b. The RHA will require that by no later than December 31, 2013, PSO will complete installation of low NOx combustion technologies and achieve a nitrogen oxide ("NOx") emission rate of 0.23 lb/MMBtu on a 30-day rolling average at each of PSO's Units.

    c. The RHA will require that beginning on January 31, 2014, PSO will comply with a new SO_2 emission rate at each of PSO's Units of 0.65 lb/MMBtu on a 30-day rolling average, and beginning on December 31, 2014, PSO will comply with a new SO_2 emission rate of 0.60 lb/MMBtu on a 12-month rolling average at each of PSO's Units. PSO will maintain those emission rates until controls are installed at one unit as provided in subparagraph (e), and the other unit is retired as provided in subparagraph (d). The RHA will include an alternative operating scenario that addresses potential service disruption of coal supplies during the time period between January 31, 2014 through April 16, 2016.

    d. The RHA will require that PSO seek all necessary regulatory approvals, and will retire one of the coal-fired generating units at Northeastern Station by April 16, 2016.

    e. The RHA will require that PSO seek all necessary regulatory approvals, and install and operate a dry-sorbent injection system, activated carbon injection system, and a fabric filter baghouse, and secure further NOx emission reductions by April 16, 2016 on the coal-fired generating unit at Northeastern Station that will continue to operate. After completion of the installation of the pollution controls required by this subparagraph, PSO will achieve a 0.15 lb/MMBtu emission rate for NOx on a 30-day rolling average basis, and a 0.40 lb/MMBtu emission rate for SO_2 on a 30-day rolling average basis.

    f. The RHA will require that during the first year of operation of the controls required under the RHA, PSO will develop and propose a monitoring program to test various operating profiles and other measures, to determine whether increased SO_2 removal efficiencies can be achieved during normal operations. Pursuant to the terms of the RHA, PSO will submit the monitoring program to EPA and ODEQ for review and will implement the monitoring program during the second and third years of operation of the dry sorbent injection system. PSO will evaluate and report the results of the monitoring program to EPA and ODEQ, and if that evaluation demonstrates that the technology is capable of sustainably achieving an emission rate of less than 0.37 lbs/MMBtu on a 30-day rolling average basis without (i) altering the unit's fuel supply, (ii) incurring additional capital costs, (iii) increasing operating expenses by more than a negligible amount, and/or (iv) adversely impacting overall unit operations, ODEQ will propose to revise the emission rate in the RHA by 60 percent of the difference between 0.40 and the demonstrated emission rate. Upon adoption after notice and opportunity for hearing, Oklahoma, through the Secretary, will submit a Regional Haze SIP revision to EPA for approval. If the demonstrated emission rate is 0.37 lbs/MMBtu or greater, no adjustment will be made to the RHA, and the emission rate from the operating Northeastern coal-fired generating unit in the RHA will remain 0.40 lbs/MMBtu.

g. The RHA will require that beginning in calendar year 2021, the Annual Capacity Factor (calculated for each calendar year as a percentage of MWH based on a rated capacity of 470 MW times 8760 hours) for the operating coal-fired generating unit at Northeastern Station will be reduced as follows:
   i. to no more than 70 percent in calendar years 2021 and 2022;
   ii. to no more than 60 percent in calendar years 2023 and 2024; and
   iii. to no more than 50 percent in calendar years 2025 and 2026.

h. The RHA will require that no later than December 31, 2026, PSO will retire the remaining operating coal-fired generating unit at Northeastern Station. However, in calendar year 2021, the RHA will require PSO to evaluate whether the projected generation from that unit can be replaced at lower or equal total projected costs from natural gas or renewable resources. Pursuant to the RHA, PSO will provide a copy of the evaluation to EPA and ODEQ. If power is available from such resources at a lower projected total cost (including consideration of PSO's need to recover its remaining investment in the units), then the operating unit will retire no later than December 31, 2025.

2. Oklahoma, through the Secretary, will submit to EPA an Interstate Transport SIP revision that addresses PSO's Units and includes, among other things, the following elements:

   a. An enforceable mechanism that addresses SO_2 reductions from sources other than those operated by PSO, to the extent necessary to achieve the anticipated visibility benefits from the 2018 regional modeling; and

   b. A provision requiring that the enforceable mechanism referred to in Paragraph 2(a) of this Attachment A be implemented if the SO_2 emission rate for the controlled unit at Northeastern is not reduced to 0.30 lbs/MMBtu or less as a result of the Paragraph 1(f) of this Attachment A.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

JUL 18 2012

OFFICE OF
AIR AND RADIATION

Mr. Stuart Solomon, President
Public Service Company of Oklahoma
212 East 6th Street
Tulsa, OK 74119

Mr. Steve Thompson, Executive Director
Oklahoma Department of Environmental Quality
P.O. Box 1677
Oklahoma City, OK 73101-1677

Dear Mr. Solomon and Mr. Thompson:

I want to express my thanks to both of you and the others who participated in the discussion on Thursday, July 12, 2012 regarding the remaining issues in Public Service Company of Oklahoma's (PSO) forward-looking and comprehensive approach to achieving emission reductions in Oklahoma. I know I speak not only for the EPA Office of Air and Radiation, but also for Sam Coleman and his team in EPA Region 6, in expressing my appreciation for all the hard work and commitment it has taken you to reach this accord.

EPA is pleased with the final agreement made by the State of Oklahoma and PSO to develop its plan for reducing emissions to meet state and federal requirements at the two coal-fired generating units at its Northeastern Station in Oologah, Oklahoma. While this agreement is focused on complying with the visibility requirements of the Clean Air Act, the control technology described in the agreement is also intended to achieve compliance with the Mercury and Air Toxics Standard (MATS). EPA supports such a comprehensive approach. Furthermore the types of controls that PSO plans to install (a combination of Dry Sorbent Injection (DSI) and subbituminous coal to meet the acid gas limits, activated carbon injection and a baghouse to meet the mercury limits, and a baghouse to meet the PM limits) are the types of controls that, when well designed and operated, EPA would expect to be able to meet the MATS limits.

EPA has every confidence that this technology, when properly installed and operated, will provide a means for PSO to meet both the visibility requirements of the Clean Air Act and the MATS requirements. This is exactly the type of agreement that will provide for a cost-effective approach to meet both the visibility requirements of the Clean Air Act and ultimately the MATS rule. EPA is committed to work closely with ODEQ in the development of the proposed SIP revision for a revised BART determination for the PSO plant based on the plan outlined in this agreement.

I look forward to the continued success of our organizations in the implementation of this important agreement.

Sincerely yours,

Gina McCarthy
Assistant Administrator

Appendix II

Revised BART Determination,

including

Supplemental BART Determination Information submitted by AEP/PSO

Oklahoma Department of Environmental Quality
Air Quality Division

Revised BART Determination **June 13, 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)**
REVIEWER:	**Lee Warden, Engineering Manager**

I. PURPOSE

The 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 final settlement agreement, partially summarized below, is the result of these discussions. On November 20, 2012, AEP/PSO submitted to DEQ the Supplemental BART Determination Information under terms of the settlement agreement.

II. SUPPLEMENTAL BART DETERMINATION INFORMATION

The Supplemental BART Determination Information lays out a plan for AEP/PSO's revised proposal for BART, as part of a long-term multi-media, multi-pollutant plan, which entails shutting down one of the two units by April 16, 2016, and installing and operating 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 Supplemental BART Determination Information acknowledges these NO_X reductions and proposes 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 proposed limits and timelines as reflected in the Supplemental BART Determination Information for the early NO_X and SO_2 emission reductions.

Table 1: Early NO_X and SO_2 Reductions

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 Supplemental BART Determination Information proposes a shutdown date for both units, and 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 Supplemental BART Determination Information provides that AEP/PSO will shut down one unit by April 16, 2016 prior to the FIP-required control date. The Supplemental BART Determination Information also proposes that AEP/PSO will 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 as BART in lieu of the more costly DFGD/SDA specified in the FIP. To further reduce emissions, the Supplemental BART Determination Information proposes capacity utilization reductions over the remaining life of the unit, beginning in the year 2021.

The Supplemental BART Determination Information 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 proposed 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 Northeastern 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, Northeastern Units 3 and 4 were determined to be BART applicable sources, subject to the BART determination requirements.

IV. 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 Northeastern 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 proposed 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 Station.

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 contemporaneous emission reductions resulting from the multi-media, multi-pollutant strategy proposed in the Supplemental BART Determination Information (through the BART timeframe) is relied upon in the evaluation of the 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 proposed strategy 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 proposed scenario, the incremental cost effectiveness worsens.

A DFGD/SDA solution would provide improvements in visibility slightly above that achieved with a DSI system. However, factoring in the proposed strategy, 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 trivial visibility improvements of approximately 0.1 dv above that of the proposed strategy over individual Class I areas and an average total improvement of 0.27 dv across the four nearest Class I areas during the time of control implementation. Visibility improvements generally must be 1 dv or greater to be perceptible to the human eye. These 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 proposed scenario, $5,690,172 per dv.

The proposed strategy provides for the shutdown of one unit (assumed to be 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 proposed scenario. Additionally, the proposed 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 will be approximately half that of the control solution established by the FIP.

Given the comparable visibility improvement, lower costs, and overall reduced environmental impact, the State has determined that an alternative control level (i.e., to the presumptive emission limits) is justified based on a careful consideration of the statutory factors, and that the proposed control constitutes BART. This determination relies upon an enhanced effectiveness provided through contemporaneous emission reductions from the multi-media, multi-pollutant strategy outlined in the Supplemental BART Determination Information and documented in Table 2. Through incorporation in the First Amended Regional Haze Agreement, this strategy is made enforceable and therefore, eligible for reliance upon in the BART determination.

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 Supplemental BART Determination Information 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. Under the First Amended Regional Haze 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, by reducing NO_X 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 Supplemental BART Determination Information also provides for decreased capacity utilization in the remaining coal-fired unit over its shortened lifetime. Under this plan, AEP/PSO will shut down the remaining coal-fired unit by December 31, 2026. The visibility impact from the two BART-eligible units will be zero after 2026. With implementation of the decreased capacity utilization limits and the retirement 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
Amended Regional Haze 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 deadline in the First Amended Regional Haze Agreement and the January 2017 FIP deadline to begin operating with BART controls.

VII. CONSTRUCTION PERMIT

Prevention of Significant Deterioration (PSD)
Northeastern Power Station 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 First Amended Regional Haze 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 Station 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 First Amended Regional Haze Agreement.

PUBLIC SERVICE COMPANY OF OKLAHOMA
A unit of American Electric Power

Public Service Company of Oklahoma
1601 Northwest Expressway, Suite 1400
Oklahoma City, OK 73118
PSOklahoma.com

November 19, 2012

Eddie Terrell, Air Quality Division Director
Oklahoma Department of Environmental Quality
P.O. Box 1677
Oklahoma City, OK 73101-1677

Re: Revised Regional Haze State Implementation Plan Requirements
Public Service Company of Oklahoma
Northeastern Station Units 3 and 4

Dear Mr. Terrell:

In accordance with Paragraph 2 of the Settlement Agreement executed by Public Service Company of Oklahoma (PSO), the Secretary of the Environment, the Oklahoma Department of Environmental Quality (ODEQ) and Sierra Club, which was issued for public comment on November 14, 2012, 77 *Fed. Reg.* 67,814, PSO herewith submits the Supplemental BART Determination Information to support revised Best Available Retrofit Technology (BART) determinations for Northeastern Station Units 3 and 4. The Supplemental BART Determination Information analyzes the cost-effectiveness and visibility improvements associated with the activities outlined in the Settlement Agreement, which include retiring Northeastern Unit 4, and installing dry sorbent injection, a fabric filter baghouse, and other controls at Northeastern Unit 3 by April 16, 2016, and taking other actions consistent with the terms of the Settlement Agreement.

It is anticipated that following the close of the public comment period, the U.S. Environmental Protection Agency (EPA) will execute the Settlement Agreement, which establishes a schedule for the proposal, adoption, and approval of a revision to the Oklahoma State Implementation Plan (SIP) to incorporate this BART determination. PSO appreciates ODEQ's commitment to promptly review the enclosed submittal, and will promptly respond to any requests for clarification or additional information.

Please contact me if any additional information is required, or if you would like to schedule a meeting to review the submittal and its supporting information.

Very truly yours,

Howard Ground

Howard Ground
Manager State Governmental & Environmental Affairs

SUPPLEMENTAL BART DETERMINATION INFORMATION

AMERICAN ELECTRIC POWER ■ NORTHEASTERN POWER PLANT

Prepared By:

TRINITY CONSULTANTS, INC.

120 East Sheridan, Suite 205
Oklahoma City, OK 73104
(405) 228-3292

9777 Ridge Drive, Suite 380
Lenexa, KS 66219
(913) 894-4500

AMERICAN ELECTRIC POWER SERVICE CORPORATION

PO Box 660164
Dallas, Texas 72566
(214) 777-1113

For :

AEP'S PUBLIC SERVICE COMPANY OF OKLAHOMA (PSO)
NORTHEASTERN STATION GENERATING PLANT

November 9, 2012

Relevant Previous Submittals:

March 30, 2007
May 30, 2008
August 2008

TABLE OF CONTENTS

1. INTRODUCTION

American Electric Power / Public Service Company of Oklahoma (AEP/PSO) operates the Northeastern Power Station and is submitting supplemental information for consideration by the Oklahoma Department of Environmental Quality (ODEQ) and the U.S. Environmental Protection Agency (EPA) in the determination of Best Available Retrofit Technology (BART) for Northeastern's Unit 3 and Unit 4. Previous analyses and other BART-related information were submitted by AEP/PSO on:

- March 30, 2007
- May 30, 2008
- August 2008

The supplemental information provided in this report is submitted in response to EPA's final decision to partially disapprove the Oklahoma Regional Haze (RH) State Implementation Plan (SIP),[1] the related RH Federal Implementation Plan (FIP), and subsequent discussions between AEP/PSO, ODEQ, and EPA regarding how best to implement BART controls at Northeastern. In the FIP, EPA evaluated Dry Flue Gas Desulfurization (DFGD) technology as compared to Wet FGD (WFGD). AEP/PSO agrees with EPA that DFGD is the appropriate selection between the two and no further analysis of WFGD is required. This submittal considers an alternative to the DFGD determined as BART in the FIP by evaluating Dry Sorbent Injection (DSI) as the SO_2 control technology combined with specific retirement dates for the Northeastern 3 and 4 Units. The discussions herein focus on an option that would allow AEP/PSO to proceed with terms and conditions laid out in the Settlement Agreement included in Appendix C to this report as opposed to the RH FIP. The key differences between the FIP and the Settlement Agreement are summarized below:

- FIP: Install and operate DFGD, with an emission limit of 0.06 lb/MMBtu, on both units
- Settlement Agreement: Shut down one of the two units by April 16, 2016 and install and operate a dry sorbent injection system (DSI), with an emission limit of 0.4 lb/MMBtu, on the other unit from April 16, 2016 to December 31, 2026, at which point the unit will also shut down

This report compares the two SO_2 control options described above by evaluating the cost effectiveness of both options and by evaluating the improvement to the existing visibility impairment for both options. Also, because the Settlement Agreement option includes the shutdown of the units, which changes the NO_X emission rates (to zero) as well, AEP/PSO has re-evalauted, and is presenting new results, of the visibility impairment associated with the NO_X BART determinations.

The modeling methods relied upon for evaluating the visibility impairment are largely the same as the methodology that was relied upon in the previous BART report. Exceptions are described in Section 2 of this report.

[1] 77 FR 16168-16197

The modeling inputs, methods, and results presented in this report followed the methods and procedures that were previously used, and approved, with a few exceptions. The changes for the current modeling compared to the modeling originally submitted are listed below. Since the changes primarily involve how the CALPOST model was applied, a detailed description of the CALPOST methods is provided in Section 2.1.

- ▲ The postprocessor POSTUTIL (Version 1.52, Level 060412) was used to repartition nitrates from the CALPUFF output file to be consistent with the total available sulfate and ammonia, prior to assessing visibility with CALPOST. Note that POSTUTIL is not among the list of regulatory models on EPA's SCRAM website. Thus, there is no regulatory approved (or default) version of POSTUTIL.
- ▲ The CALPOST model version was updated to Version 6.221, Level 080724.
- ▲ The CALPOST visibility calculation method was updated from Method 6 to Method 8. 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.
- ▲ The annual average background concentrations used in the CALPOST models for each of the four Class I Areas of interest – Caney Creek Wilderness (CACR), Hercules Glades Wilderness (HERC), Upper Buffalo Wilderness (UPBU), and Wichita Mountains National Wildlife Refuge (WICH) – were updated based on values found in the 2010 FLAG guidance.

The CALMET processing was not updated as a part of the analyses presented in this report. That is, the same meteorological dataset used in the original (2008) analyses was used again. This dataset was processed using CALMET v.5.53a. Re-processing of the meteorological data is not prudent for the reasons listed below.

- ▲ The intent of this report is to provide supplemental information for comparative purposes; therefore, it is important to maintain consistency with past analyses where possible.
- ▲ It is expected that changes to the CALMET processing would not significantly impact the BART analysis metric since that metric is a relative comparison, i.e., the CALMET change would apply to both baseline and post-control modeling.
- ▲ Creating a new meteorological dataset would take several months.
- ▲ Re-running CALMET would require development of a new protocol and potential lengthy negotiations of numerous user-defined values for which EPA may or may not have published guidance since the original analysis. As an example, AEP/PSO is familiar with EPA's August 2009 memo regarding CALMET settings in which EPA provides recommendations (but not defaults) for R and RMAX values.
- ▲ The existing meteorological dataset has been recently reviewed and approved for use by EPA numerous times for AEP and for several other facilities in EPA Region 6.

2.1 CALPOST

The CALPOST visibility processing completed for this BART analysis is based on the October 2010 guidance from the Federal Land Managers Air Quality Related Values Workgroup (FLAG). The

2010 FLAG guidance, which was issued in draft form on July 8, 2008 and published as final guidance in December 2010, makes technical revisions to the previous guidance issued in December 2000.

Visibility impairment is quantified using the light extinction coefficient (b_{ext}), which is expressed in terms of the haze index expressed in deciviews (dv). The haze index (*HI*) is calculated as follows:

$$HI\,(\mathrm{dv}) = 10\ln\left(\frac{b_{ext}}{10}\right)$$

The impact of a source is determined by comparing the *HI* attributable to a source relative to estimated natural background conditions. The change in the haze index, in deciviews, also referred to as "delta dv," or Δdv, based on the source and background light extinction is based on the following equation:

$$\Delta\,\mathrm{dv} = 10 * \ln\left[\frac{\mathrm{b_{ext,\ background}} + \mathrm{b_{ext,\ source}}}{\mathrm{b_{ext,\ background}}}\right]$$

The Interagency Monitoring of Protected Visual Environments (IMPROVE) workgroup adopted an equation for predicting light extinction as part of the 2010 FLAG guidance (often referred to as the new IMPROVE equation). The new IMPROVE equation is as follows:

$$b_{ext} = \begin{array}{l} 2.2\,f_S(RH)[\mathrm{NH_4(SO_4)_2}]_{\mathrm{Small}} + 4.8\,f_L(RH)[\mathrm{NH_4(SO_4)_2}]_{\mathrm{Large}} + \\ 2.4\,f_S(RH)[\mathrm{NH_4NO_3}]_{\mathrm{Small}} + 5.1\,f_L(RH)[\mathrm{NH_4NO_3}]_{\mathrm{Large}} + \\ 2.8[\mathrm{OC}]_{\mathrm{Small}} + 6.1[\mathrm{OC}]_{\mathrm{Large}} + 10[\mathrm{EC}] + 1[\mathrm{PMF}] + 0.6[\mathrm{PMC}] + \\ 1.4\,f_{SS}(RH)[\mathrm{Sea\ Salt}] + b_{\mathrm{Site-specific\ Rayleigh\ Scattering}} + 0.33[\mathrm{NO_2}] \end{array}$$

Visibility impairment predictions relied upon in this BART analysis used the equation shown above. The use of this equation is referred to as "Method 8" in the CALPOST control file. The use of Method 8 requires that one of five different "modes" be selected. The modes specify the approach for addressing the growth of hygroscopic particles due to moisture in the atmosphere. "Mode 5" has been used in this BART analysis. Mode 5 addresses moisture in the atmosphere in a similar way as to "Method 6", where "Method 6" is specified as the preferred approach for use with the old IMPROVE equation in the CENRAP BART modeling protocol.

CALPOST Method 8, Mode 5 requires the following:

- ▲ Annual average concentrations reflecting natural background for various particles and for sea salt
- ▲ Monthly RH factors for large and small ammonium sulfates and nitrates and for sea salts
- ▲ Rayleigh scattering parameter corrected for site-specific elevation

Tables 2-1 to 2-4 below show the values for the data described above that were input to CALPOST for use with Method 8, Mode 5. The values were obtained from the 2010 FLAG guidance.

TABLE 2-1. ANNUAL AVERAGE BACKGROUND CONCENTRATION

Class I Area	$(NH_4)_2SO_4$ (µg/m^3)	NH_4NO_3 (µg/m^3)	OM (µg/m^3)	EC (µg/m^3)	Soil (µg/m^3)	CM (µg/m^3)	Sea Salt (µg/m^3)	Rayleigh (Mm^{-1})
CACR	0.23	0.1	1.8	0.02	0.5	3	0.03	11
UPBU	0.23	0.1	1.8	0.02	0.5	3	0.03	11
HERC	0.23	0.1	1.8	0.02	0.5	3	0.02	11
WICH	0.12	0.1	0.6	0.02	0.5	3	0.03	11

TABLE 2-2. fL(RH) LARGE RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CACR	2.77	2.53	2.37	2.43	2.68	2.71	2.59	2.6	2.71	2.69	2.67	2.79
UPBU	2.71	2.48	2.31	2.33	2.61	2.64	2.57	2.59	2.71	2.58	2.59	2.72
HERC	2.7	2.48	2.3	2.3	2.57	2.59	2.56	2.6	2.69	2.54	2.57	2.72
WICH	2.39	2.25	2.10	2.11	2.39	2.24	2.02	2.13	2.35	2.22	2.28	2.41

TABLE 2-3. f_S(RH) SMALL RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CACR	3.85	3.44	3.14	3.24	3.66	3.71	3.49	3.51	3.73	3.72	3.68	3.88
UPBU	3.73	3.33	3.03	3.07	3.54	3.57	3.43	3.5	3.71	3.51	3.52	3.74
HERC	3.7	3.33	3.01	3.01	3.47	3.48	3.41	3.51	3.67	3.43	3.46	3.73
WICH	3.17	2.94	2.69	2.68	3.15	2.86	2.49	2.70	3.07	2.87	2.97	3.20

TABLE 2-4. f_{SS}(RH) SEA SALT RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CACR	3.9	3.52	3.31	3.41	3.83	3.88	3.69	3.68	3.82	3.76	3.77	3.93
UPBU	3.85	3.47	3.23	3.27	3.72	3.78	3.69	3.7	3.84	3.64	3.67	3.86
HERC	3.86	3.51	3.23	3.22	3.66	3.72	3.69	3.73	3.81	3.57	3.65	3.88
WICH	3.35	3.12	2.91	2.94	3.40	3.21	2.84	3.01	3.32	3.10	3.20	3.40

3. SUPPLEMENTAL INFORMATION FOR THE NO_X BART DETERMINATION

EPA has approved as BART a NO_X emission rate of 0.15 lb/MMBtu.[2] Even though the NO_X BART determination is final, as part of this report AEP/PSO is re-modeling in order to consider the impact of the unit shutdowns prescribed by the Settlement Agreement, and also in order to use the updated version of CALPOST as described in Section 2. This will allow for an apples-to-apples comparison of the NO_X BART determination visibility impact associated with the SO_2 controls that are the primary focus of this report.

Table 3-1 shows a summary of visibility improvement, based on the updated modeling, attributable to a NO_X emission rate of 0.15 lb/MMBtu for Unit 3 plus the shutdown of Unit 4. Detailed year-by-year modeling results are presented in Appendix B.

TABLE 3-1. SUMMARY OF VISIBILITY IMPROVEMENT ASSOCIATED WITH NO_X CONTROL SCENARIO

	Baseline			Unit 4 Shutdown / Unit 3 NO_X Controlled, SO_2 Baseline		
Class I Area	**Max. Impact (Δdv)**	**98th %-tile (Δdv)**	**# Days > 0.5 Δdv**	**Max. Impact (Δdv)**	**98th %-tile (Δdv)**	**# Days > 0.5 Δdv**
CACR	3.710	1.927	121	1.738	0.609	26
HERC	3.683	1.291	85	1.758	0.595	23
UPBU	5.196	1.389	87	2.453	0.563	20
WICH	5.480	1.937	106	2.509	0.865	31

Table 3-1a presents the emission rates input in the modeling that resulted in the output presented in Table 3-1.

TABLE 3-1a. SUMMARY OF EMISSION RATES USED IN BASELINE AND NO_X CONTROL SCENARIO

Scenario	Unit	NO_X (lb/MMBtu)	NO_X (lb/hr)	SO_2 (lb/MMBtu)	SO_2 (lb/hr)	SO_4 (lb/MMBtu)	SO_4 (lb/hr)
Baseline	Unit 3	0.536	3,115.5	1.054	6,126.3	0.011	66.3
	Unit 4	0.491	2,746.6	1.060	5,929.6	0.011	62.3
Unit 4 Shutdown / Unit 3 NO_X Controlled, SO_2 Baseline	Unit 3	0.15	871.9	1.054	6,126.3	0.011	66.3
	Unit 4	0	0	0	0	0	0

[2] 77 FR 16168-16197

4. SUPPLEMENTAL INFORMATION FOR THE SO_2 BART DETERMINATIONS

This section provides supplemental information regarding SO_2 control options prescribed in the above-mentioned Settlement Agreement scenario and the FIP scenario.

- ▲ FIP Scenario: Install and operate DFGD, with an emission limit of 0.06 lb/MMBtu, on both Unit 3 and Unit 4
- ▲ Settlement Agreement Scenario: Shut down Unit 4 by 2016 and install and operate DSI, with an emission limit of 0.4 lb/MMBtu, on Unit 3 from 2016 to 2026, at which point it will also shut down

Because the Settlement Agreement scenario involves the immediate (in 2016) shutdown of Unit 4 and, for Unit 3, a phased reduction in operations (from 2016 to 2026), the evaluations completed in this report – the cost effectiveness evaluation and the visibility impairment evaluation – are completed on a scenario basis rather than a unit-by-unit basis. These evaluations are described below following a brief description of the two SO_2 control options being considered.

DRY SORBENT INJECTION

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 Flue Gas Desulfurization (FGD) option because the existing ductwork acts as the absorber vessel, obviating 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.[3] This control is a technically feasible option for the control of SO_2 for Unit 3.

DRY FLUE GAS DESULFURIZATION

There are various designs of dry flue gas desulfurization (DFGD) systems. In the spray dryer absorber (SDA) design, a fine mist of lime slurry is sprayed into an absorption vessel where the SO_2 is absorbed by the slurry droplets. The absorption of the SO_2 leads to the formation of calcium sulfite and calcium sulfate within the droplets. The liquid-to-gas ratio is such that the heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the vessel. This leads to the formation of a dry powder which is carried out with the gas and collected with a fabric filter.

In the circulating dry scrubbing (CDS) process, the flue gas is introduced into the bottom of a reactor vessel at high velocity through a venturi nozzle; the exhaust is mixed with water, hydrated lime, recycled flyash and CDS reaction products. The intensive gas-solid mixing that occurs in the reactor promotes the reaction of sulfur oxides in the flue gas with the dry lime particles. The mixture of

[3] "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.

reaction products (calcium sulfite/sulfate), unreacted lime, and fly ash is carried out with the exhaust and collected in an ESP or fabric filter. A large portion of the collected particles is recycled to the reactor to sustain the bed and improve lime utilization.

DFGD control efficiencies range from 60 to 95 percent.[4] This is a technically feasible option for the control of SO_2 for Unit 3.

4.1 COST EFFECTIVENESS EVALUATION

See Appendix A for the detailed cost breakdown.

The capital and operating costs of the DSI control option, i.e., the Settlement Agreement scenario, were estimated based on EPA's Control Cost Manual ("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 the 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 costs 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 shutdown.

In addition to the Manual-based estimates for DSI on one unit, AEP/PSO has provided, for comparison purposes, the cost estimate for a DSI control system based on an engineering analysis completed by AEP. To illustrate the difference, notice that the Manual-based estimate results in a total capital investment of approximately $111 million whereas the engineering estimate is approximately $163 million. Despite this difference, per previous discussions with ODEQ and EPA, AEP strictly used the Manual-based estimates in all cost effectiveness and incremental cost effectiveness calculations. The resulting total annual cost of control for the Settlement Agreement scenario is approximately $25 million.

The costs presented for DFGD, i.e., the FIP scenario, were taken from EPA's Technical Support Document (TSD) published with the RH FIP. These costs also follow the Manual with a few exceptions that are footnoted in Appendix A. The total capital investment for DFGD for two units is

[4] EPA Basic Concepts in Environmental Sciences, Module 6: Air Pollutants and Control Techniques http://www.epa.gov/eogapti1/module6/sulfur/control/control.htm

taken to be approximately $274 million, and the total annual cost of control is taken to be approximately $45 million.

AEP/PSO commented on EPA's draft FIP (on May 23, 2011) stating, "EPA's Cost Effectiveness Analysis significantly underestimates the costs of [DFGD] controls," and this assertion is reiterated here. The cost estimate relied on by EPA was not developed specifically for PSO's Northeastern units but derived from a critique of the cost estimates presented in the Oklahoma SIP for Oklahoma Gas and Electric's (OG&E's) Sooner and Muskogee units. Once EPA derived its own estimates for DFGD at the Sooner and Muskogee units, EPA applied that estimate to the Northeastern units without taking into account any of the site-specific information presented in the original BART submittals.

Since the submittal of the original BART reports, AEP has completed a more detailed cost estimate for a DFGD system at a similar facility, including the development of current estimates for removal and foundations, direct equipment purchases, detailed design and engineering, and specialty subcontracts (electrical, civil, and instrumentation and controls). These estimates confirm that the cost figures relied on in the RH FIP are significantly understated. AEP/PSO is providing – for comparison purposes – this recent engineering cost analysis for DFGD. This analysis results in a total capital investment value of approximately $390 million (for one unit only).

The calculation of annual tons reduced for the Settlement Agreement scenario was completed by subtracting the estimated total controlled annual emission rate from the baseline total annual emission rate. The baseline total emission rate was based on each 4,775-MMBtu/hr unit operating at an 85 percent capacity utilization with an SO_2 emission rate of 0.9 lb/MMBtu.[5] The total controlled annual emission rate was calculated based on a DSI emission rate of 0.4 lb/MMBtu and in accordance with the Settlement Agreement-required schedule of capacity utilization reductions.

Lastly, the cost effectiveness values, in dollars per ton of SO_2 removed, were calculated by dividing the annual cost of control by the annual tons reduced. The resulting cost effectiveness values are: for the Settlement Agreement scenario, $942/ton, and for the FIP scenario, $1,544/ton. An incremental cost analysis was also performed to show the incremental increase in costs between the scenarios. The result is that the incremental FIP scenario cost is $7,794/ton more than the Settlement Agreement scenario.

[5] The use of a 0.9-lb/MMBtu baseline emission rate is consistent with EPA's use of this emission rate in its FIP and TSD. Moreover, this emission rate is the appropriate emission rate as it is reflective of the baseline period based on CEMS data. The interim reductions to 0.6 lb/MMBtu and 0.65 lb/MMBtu established in the Settlement Agreement are reflected in the cumulative reductions analyzed in this report.

4.2 EVALUATION OF VISIBILITY IMPACTS

An initial impact analysis was conducted to assess the visibility improvement related to SO_2 reductions based on the shut down of Unit 4 and installation of DSI on Unit 3. Table 4-2 provides a summary comparison of impacts in terms of the maximum modeled visibility impact, the 98th percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv. Detailed year-by-year modeling results are presented in Appendix B.

TABLE 4-1. SUMMARY OF VISIBILITY IMPROVEMENT ASSOCIATED WITH DSI SO_2 CONTROL ON UNIT 3 AND SHUTDOWN OF UNIT 4

	Baseline			Unit 4 Shutdown / Unit 3 SO_2 Controlled (DSI), NO_X Baseline		
Class I Area	**Max. Impact (Δdv)**	**98th %-tile (Δdv)**	**# Days > 0.5 Δdv**	**Max. Impact (Δdv)**	**98th %-tile (Δdv)**	**# Days > 0.5 Δdv**
CACR	3.710	1.927	121	1.131	0.637	25
HERC	3.683	1.291	85	1.300	0.408	14
UPBU	5.196	1.389	87	1.829	0.534	13
WICH	5.480	1.937	106	1.932	0.618	21

Table 4-1a presents the emission rates input in the modeling that resulted in the output presented in Table 4-1.

TABLE 4-1a. SUMMARY OF EMISSION RATES USED IN BASELINE AND SO_2 CONTROL SCENARIO INVOLVING DSI AND UNIT SHUTDOWNS

Scenario	Unit	NO_X (lb/MMBtu)	NO_X (lb/hr)	SO_2 (lb/MMBtu)	SO_2 (lb/hr)	SO_4 (lb/MMBtu)	SO_4 (lb/hr)
Baseline	Unit 3	0.536	3,115.5	1.054	6,126.3	0.011	66.3
	Unit 4	0.491	2,746.6	1.060	5,929.6	0.011	62.3
Unit 4 Shutdown / Unit 3 SO_2 Controlled (DSI), NO_X Baseline	Unit 3	0.536	3,115.5	0.4	2,325.0	0.004	25.1
	Unit 4	0	0	0	0	0	0

Further analysis was completed to compare the Settlement Agreement scenario, as a whole, and the FIP scenario. This analysis, the results of which are summarized in Table 4-3, included post-control rates for both SO_2 and NO_X for each scenario. Detailed year-by-year modeling results are presented in Appendix B.

TABLE 4-2. SUMMARY OF VISIBILITY IMPROVEMENT – COMPARISON OF SCENARIOS

Class I Area	Settlement Agreement Scenario Max. Impact (Δdv)	Settlement Agreement Scenario 98th %-tile (Δdv)	Settlement Agreement Scenario # Days > 0.5 Δdv	FIP Scenario Max. Impact (Δdv)	FIP Scenario 98th %-tile (Δdv)	FIP Scenario # Days > 0.5 Δdv
CACR	0.778	0.346	5	0.577	0.277	2
HERC	0.814	0.246	3	0.531	0.197	3
UPBU	1.152	0.247	4	0.783	0.238	3
WICH	1.194	0.372	6	0.867	0.257	1

Table 4-2a presents the emission rates input in the modeling that resulted in the output presented in Table 4-2.

TABLE 4-2a. SUMMARY OF EMISSION RATES USED IN SETTLEMENT AGREEMENT AND FIP SO_2 CONTROL SCENARIOS

Scenario	Unit	NO_X (lb/MMBtu)	NO_X (lb/hr)	SO_2 (lb/MMBtu)	SO_2 (lb/hr)	SO_4 (lb/MMBtu)	SO_4 (lb/hr)
Settlement Agreement Scenario	Unit 3	0.15	871.9	0.4	2,325.0	0.004	25.1
	Unit 4	0	0	0	0	0	0
FIP Scenario	Unit 3	0.15	871.9	0.06	348.7	0.001	3.8
	Unit 4	0.15	839.1	0.06	335.6	0.001	3.5

As shown in Table 4-2, both the FIP scenario and the Settlement Agreement scenario show 98th percentile impact values of well below 0.5 Δdv for all Class I areas. Moreover, the differences in the 98th percentile values between the two scenarios are very small, varying between from 0.01 to 0.12 Δdv depending on Class I area. Also, the Settlement Agreement scenario represents a substantial reduction, 80 to 82 percent depending on the Class I area, in visibility impairment compared to the baseline.

In addition, while the FIP scenario will have somewhat lower impacts until 2026, the visibility impact from the Settlement Agreement scenario will be zero after 2026 with the full retirement of both units compared to continued operation of two controlled units under the FIP scenario. It is also interesting to note that the total post-2014 emissions, in total tons, for the two scenarios are similar with the Settlement Agreement scenario resulting in somewhat less emissions overall. For the period from 2014 to 2046, the FIP scenario would result in 127,997[6] tons of SO_2 overall, a reduction of 895,977 tons compared to the baseline emission rate applied to the same period. The Settlement Agreement scenario is expected to result in 109,851[7] tons of SO_2 overall, a reduction of 914,123 tons compared to the baseline emission rate. Thus, the Settlement Agreement scenario provides for removal of an additional 18,145 tons of SO_2 above and beyond the FIP scenario. Note that in regards to NO_X, even more drastic reductions are provided for by the shutdowns stipulated in the Settlement Agreement scenario compared to the FIP scenario.

[6] Based on both units emitting at 0.9 lb/MMBtu for two years and 0.06 lb/MMBtu for 30 years.
[7] Based on the tiered emission rate and capacity utilization requirements of the Settlement Agreement.

Lastly, it is important to note that because of the phase down and eventual shut down of both units in the Settlement Agreement scenario, in the interest of meeting overall Regional Haze goals, the Settlement Agreement scenario gets to the glide path in a quicker timeframe.

4.3 PROPOSED BART FOR SO_2

Although the temporarily lower emission rate associated with the FIP scenario provides for slight visibility improvement when compared to the Settlement Agreement scenario, the small improvement does not justify the incremental cost, both in terms of cost effectiveness and in terms of up-front capital costs.

Therefore, AEP/PSO concludes that the combination of emissions control and unit retirements called for in the Settlement Agreement completely satisfy the BART requirements for Northeastern Station units 3 and 4. A summary of the requirements is provided below.

TABLE 4-3. SUMMARY OF PROPOSED SO_2 BART DETERMINATIONS

Emission Unit	BART Limit	Controls
Unit 4	Unit Shutdown by April 16, 2016	
Unit 3	0.4 lb/MMBtu 30-day rolling average	Dry Sorbent Injection, Unit Shutdown by December 31, 2026

APPENDIX A

SO_2 CONTROL COST CALCULATIONS

Estimated Average Cost ($/ton) of a Dry Sorbent Injection (DSI) System

Cost Type	Default Estimate Methodology from EPA's Control Cost Manual [a]	Cost Estimate Based on EPA's Control Cost Manual (One Unit)	*FOR COMPARISON* Cost Estimate Based on Engineering Study (2016$) (One Unit)
CAPITAL COSTS			
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment Cost (EC), including instrumentation	--	$49,883,940	$49,883,940
Sales Tax	3% of EC [b]	$0 [h]	$0 [h]
Freight	5% of EC [b]	$0 [h]	$0 [h]
Purchased Equipment Costs (PEC)		*$49,883,940*	*$49,883,940*
Direct Installation Costs			
Foundations and supports	6% of PEC [b]	$2,993,036	$11,433,582
Handling and erection	40% of PEC [b]	$19,953,576	$12,705,233
Electrical	1% of PEC [b]	$498,839	$8,181,380
Piping	5% of PEC [b]	$2,494,197	$9,536,419
Insulation for ductwork	3% of PEC [b]	$1,496,518	$3,181,956
Painting	1% of PEC [b]	$498,839	$1,232,111
Direct Installation Costs (DIC)		*$27,935,006*	*$46,270,680*
Other Direct Costs			
Site Preparation Costs (SPC)	--	$10,849,305	$10,849,305
Buildings Costs (BC)	--	$5,204,446	$5,204,446
Landfill Construction	--	$0 [i]	$0 [i]
Other Direct Costs (ODC)		*$16,053,751*	*$16,053,751*
Total Direct Capital Costs (DC = PEC + DIC + ODC)		*$93,872,698*	*$112,208,371*
Indirect Capital Costs			
Engineering	10% of PEC [b]	$4,988,394	$24,202,634
Construction and field expenses	10% of PEC [b]	$4,988,394	$8,977,897
Contractor fees	10% of PEC [b]	$4,988,394	$280,800
Start-up	1% of PEC [b]	$498,839	$3,562,477
Performance test	1% of PEC [b]	$498,839	$514,443
Contingencies	3% of PEC [b]	$1,496,518	$13,676,183
Total Indirect Capital Costs (IC)		*$17,459,379*	*$51,214,433*
TOTAL CAPITAL INVESTMENT (TCI = DC + IC)		*$111,332,077*	*$163,422,804*
OPERATING COSTS			
Direct Operating Costs			
Fixed O&M Costs (Labor and Materials)			
Operating Labor ($14.24/hour) [d]	8 hr/shift, 3 shifts/day [c]	$124,742	$997,939
Operating Labor Supervision	15% of op. labor [c]	$18,711	$0
Maintenance Labor ($14.24/hour) [d]	2 hr/shift, 3 shifts/day [c]	$31,186	$0
Maintenance materials	100% of maint. labor [c]	$31,186	$407,800
Fixed O&M Costs		*$205,825*	*$1,405,739*
Other Direct Operating Costs (e.g., utilities)			
Sorbent (22,776 tons/yr, $230/ton, Avg. CU) [e,f]	--	$3,500,257	$3,500,257
Electricity (5,696 kW/yr, $0.05588/kW, Avg. CU) [f]	--	$1,862,726	$1,862,726
Water (zero cost)	--	$0	$0
Waste Disposal (zero cost)	--	$0	$0
Bag and Cage Replacement (9,424 bags/cages;… …$114 & 3-yr cycle for bag; $29 & 6-yr cycle for cages)	--	$403,661	$403,661
Other Direct Operating Costs		*$5,766,644*	*$5,766,644*
Total Direct Operating Costs (DOC)		*$5,972,469*	*$7,172,383*
Indirect Operating Costs			
Overhead	60% of O&M [c]	$0 [j]	$0 [j]
Property tax	1% of TCI [c]	$946,323 [j]	$1,389,094 [j]
Insurance	1% of TCI [c]	$11,690 [j]	$17,159 [j]
Administration	2% of TCI [c]	$2,226,642	$3,268,456
Capital Recovery (10 years, 7 %) (CRF_{10})	0.1424 of TCI	$15,851,183	$23,267,731
Capital Recovery (30 years, 7 %) (CRF_{30})	0.0806 of TCI	--	--
Total Indirect Operating Costs (IOC)		*$19,035,837*	*$27,942,440*
TOTAL ANNUALIZED COSTS (TAC = DOC + IOC)		*$25,008,306*	*$35,114,823*

COST EFFECTIVENESS EVALUATION

Total Annual Cost of Control (DSI on Unit 3) $25,008,306

Baseline SO_2 Emissions, TPY (at 0.9 lb/MMBtu for two units) [g] 31,999

Post-Control SO_2 Emissions, TPY (zero for one unit and decreasing over the 10-yr life for the controlled unit)…

Year	Capcity Utilization	Emissions, TPY
2016, post-4/16	75	4,641
2017	75	6,274
2018	75	6,274
2019	75	6,274
2020	75	6,274
2021	70	5,856
2022	70	5,856
2023	60	5,019
2024	60	5,019
2025	50	4,183
2026	50	4,183
Average	66.8	5,441

Removed SO_2 Emissions, TPY (26,558)

Cost/Ton Pollutant Removed (DSI-Controlled) $942

[a] Default estimates are based on information published in the EPA Cost Control Manual, Sixth Edition. These estimates are used for all cost calculations except for the "Purchaed Equipment Costs," which are based on a six-month, site-specific, bottom-up engineering study; the "Other Direct Operating Costs" such as for sorbent usage, electricity, and bag and cage replacement; and the deviations discussed in note "j" below.

[b] EPA Cost Control Manual (CCM), Sixth Edition, Section 2.6.1.2, Table 2-8, p2-48.

[c] EPA Cost Control Manual, Sixth Edition, Table 2.9.

[d] Labor rates based on engineering estimates.

[e] The sorbent/reagent is sodium bicarbonate. The usage rate is based on average and maximum fuel-sulfur specifications of 0.8 and 0.9, respectively.

[f] The average capacity utilization, CU, over the 10-year life of the DSI is: 66.8%

[g] Based on a heat input capacity of 4,775 MMBtu/hr and a capacity utilization, CU, of 85 % (consistent with previous estimates).

[h] Sales tax and freight are included in the estimate of equipment cost (EC).

[i] No landfill construction costs are expected with the DSI option.

[j] In the FIP TSD, EPA used alternative (compared to the Control Cost Manual) estimates for these costs, i.e., zero for Overhead, 0.85 % of TCI for Property tax, and 0.0105 % of TCI for Insurance. These same estimates are used here for consistency.

Estimated Average Cost ($/ton) of a DFGD System

Cost Type	Cost Estimate Based on EPA's FIP TSD (Two Units)	Cost Estimate Based on EPA's FIP TSD (One Unit) *(all costs are assumed to be one-half of the costs for two units)*	*FOR COMPARISON* Cost Estimate Based on Engineering Study (2016$) (One Unit)
CAPITAL COSTS			
Direct Costs			
Purchased Equipment Costs (PEC)	*All Capital Costs except landfill construction were included in a single PEC value.*		
Equipment Cost (EC), including instrumentation			$97,565,272
Sales Tax			$0
Freight			$4,911,062
Purchased Equipment Costs (PEC)	*$249,100,000*	*$124,550,000*	*$102,476,334*
Direct Installation Costs			
Foundations and supports	*All Capital Costs except landfill construction were included in a single PEC value.*		$24,696,782
Handling and erection			$52,073,459
Electrical			$14,145,234
Piping			$15,165,588
Insulation for ductwork			$10,808,407
Painting			$2,156,162
Direct Installation Costs (DIC)			*$119,045,632*
Other Direct Costs	--		
Site Preparation Costs (SPC)	--		$23,427,157
Buildings Costs (BC)	--		$22,601,520
Landfill Construction	$25,000,000	$12,500,000	$12,500,000
Other Direct Costs (ODC)	*$25,000,000*	*$12,500,000*	*$58,528,677*
Total Direct Capital Costs (DC = PEC + DIC + ODC)			*$280,050,643*
Indirect Capital Costs			
Engineering	*All Capital Costs except landfill construction were included in a single PEC value.*		$44,632,242
Construction and field expenses			$15,363,554
Contractor fees			$1,476,991
Start-up			$12,249,202
Performance test			$1,057,312
Contingencies			$0
Total Indirect Capital Costs (IC)			*$74,779,301*
TOTAL CAPITAL INVESTMENT (TCI = DC + IC)	*$274,100,000*	*$137,050,000*	*$354,829,944*
OPERATING COSTS			
Direct Operating Costs			
Fixed O&M Costs (Labor and Materials)			
Operating Labor	*All O&M costs were included in a single value.*		$884,000
Operating Labor Supervision			$1,331,000
Maintenance Labor			$1,997,000
Maintenance materials			$0
Fixed O&M Costs	$4,116,350	$2,058,175	*$4,212,000*
Other Direct Operating Costs (e.g., utilities)			
Sorbent	$6,178,600	$3,089,300	$4,157,485
Electricity	$3,022,200	$1,511,100	$4,730,400
Water	$423,100	$211,550	$453,050
Waste Disposal	$727,981	$363,991	$1,546,663
Bag and Cage Replacement	$572,000	$286,000	$483,000
Other Direct Operating Costs			
Total Direct Operating Costs (DOC)	*$15,040,231*	*$7,520,116*	*$19,794,598*
Indirect Operating Costs			
Overhead	$0 [i]	$0 [i]	$0 [i]
Property tax	$2,329,850 [i]	$1,164,925 [i]	$3,016,055 [i]
Insurance	$28,781 [i]	$14,390 [i]	$37,257 [i]
Administration	$5,482,000	$2,741,000	$7,096,599
Capital Recovery (10 years, 7 %) (CRF_{10})	--	--	--
Capital Recovery (30 years, 7 %) (CRF_{30})	$22,088,733	$11,044,367	$28,594,469
Total Indirect Operating Costs (IOC)	*$29,929,364*	*$14,964,682*	*$38,744,380*
TOTAL ANNUALIZED COSTS (TAC = DOC + IOC)	*$44,969,595*	*$22,484,797*	*$58,538,978*
COST EFFECTIVENESS EVALUATION			
Total Annual Cost of Control	$44,969,595	$22,484,797	$58,538,978
Removed SO_2 Emissions, TPY	(29,119)	(14,560)	(14,933)
Cost/Ton Pollutant Removed	$1,544	$1,544	$3,920

APPENDIX B

DETAILED MODELING RESULTS TABLES

DETAILED RESULTS – BASELINE
(summary of which is presented in Table 3-1 and Table 4-1)

	2001			2002			2003			Total	Highest	Highest
Class I Area	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)
CACR	37	1.927	3.100	41	1.290	3.710	43	1.664	3.004	121	1.927	3.710
HERC	34	1.179	2.528	23	0.867	2.576	28	1.291	3.683	85	1.291	3.683
UPBU	32	1.389	2.938	25	0.938	1.800	30	1.180	5.196	87	1.389	5.196
WICH	28	1.228	5.480	34	1.339	2.429	44	1.937	3.424	106	1.937	5.480

DETAILED RESULTS – UNIT 4 SHUTDOWN / UNIT 3 NO_X CONTROLLED, SO_2 BASELINE
(summary of which is presented in Table 3-1)

	2001			2002			2003			Total	Highest	Highest
Class I Area	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)
CACR	10	0.609	1.324	8	0.513	1.738	8	0.533	1.257	26	0.609	1.738
HERC	9	0.520	1.086	3	0.366	1.039	11	0.595	1.758	23	0.595	1.758
UPBU	9	0.528	1.146	3	0.346	0.935	8	0.563	2.453	20	0.563	2.453
WICH	8	0.619	2.509	8	0.623	0.892	15	0.865	1.598	31	0.865	2.509

SUMMARY OF RESULTS – UNIT 4 SHUTDOWN / UNIT 3 SO_2 CONTROLLED (DSI), NO_X BASELINE
(summary of which is presented in Table 4-1)

	2001			2002			2003			Total	Highest	Highest
Class I Area	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)
CACR	9	0.637	1.118	6	0.439	1.131	10	0.584	0.993	25	0.637	1.131
HERC	5	0.408	1.019	4	0.291	0.872	5	0.298	1.300	14	0.408	1.300
UPBU	8	0.534	1.348	2	0.293	0.515	3	0.379	1.829	13	0.534	1.829
WICH	7	0.417	1.932	4	0.356	0.885	10	0.618	1.091	21	0.618	1.932

SUMMARY OF RESULTS – SETTLEMENT AGREEMENT SCENARIO
(summary of which is presented in Table 4-2)

	2001			2002			2003			Total	Highest	Highest
Class I Area	**# Days > 0.5 Δdv**	**98^{th} %-tile (Δdv)**	**Max. Impact (Δdv)**	**# Days > 0.5 Δdv**	**98^{th} %-tile (Δdv)**	**Max. Impact (Δdv)**	**# Days > 0.5 Δdv**	**98^{th} %-tile (Δdv)**	**Max. Impact (Δdv)**	**# Days > 0.5 Δdv**	**98^{th} %-tile (Δdv)**	**Max. Impact (Δdv)**
CACR	2	0.346	0.637	1	0.240	0.778	2	0.297	0.585	5	0.346	0.778
HERC	0	0.213	0.483	0	0.170	0.496	3	0.246	0.814	3	0.246	0.814
UPBU	2	0.247	0.532	0	0.172	0.369	2	0.231	1.152	4	0.247	1.152
WICH	2	0.241	1.194	0	0.271	0.451	4	0.372	0.677	6	0.372	1.194

SUMMARY OF RESULTS – FIP SCENARIO
(summary of which is presented in Table 4-2)

	2001			2002			2003			Total	Highest	Highest
Class I Area	**# Days > 0.5 Δdv**	**98^{th} %-tile (Δdv)**	**Max. Impact (Δdv)**	**# Days > 0.5 Δdv**	**98^{th} %-tile (Δdv)**	**Max. Impact (Δdv)**	**# Days > 0.5 Δdv**	**98^{th} %-tile (Δdv)**	**Max. Impact (Δdv)**	**# Days > 0.5 Δdv**	**98^{th} %-tile (Δdv)**	**Max. Impact (Δdv)**
CACR	1	0.277	0.577	1	0.196	0.503	0	0.252	0.435	2	0.277	0.577
HERC	1	0.197	0.531	0	0.129	0.401	2	0.119	0.527	3	0.197	0.531
UPBU	2	0.238	0.735	0	0.129	0.257	1	0.139	0.783	3	0.238	0.783
WICH	1	0.187	0.867	0	0.163	0.427	0	0.257	0.478	1	0.257	0.867

APPENDIX C

SETTLEMENT AGREEMENT

<u>SETTLEMENT AGREEMENT</u>

This Settlement Agreement ("Agreement") is entered into by Public Service Company of Oklahoma ("PSO"), the Secretary of the Environment on behalf of the State of Oklahoma ("Secretary"), the Oklahoma Department of Environmental Quality ("ODEQ"), the United States Environmental Protection Agency ("EPA"), and the Sierra Club. PSO, the Secretary, ODEQ, EPA, and the Sierra Club are hereinafter collectively referred to as "the Parties" for purposes of this Agreement.

<u>RECITALS</u>

A. On December 28, 2011, EPA issued a final rule entitled, "Approval and Promulgation of Implementation Plans; Oklahoma; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Best Available Retrofit Technology Determinations," 76 Fed. Reg. 81,728 (Dec. 28, 2011) (the "Final Rule").

B. The Final Rule partially approved and partially disapproved Oklahoma's state implementation plan ("SIP") submitted under the "visibility" and "interstate transport" provisions of the Clean Air Act ("CAA"), 42 U.S.C. § 7410, 7491, and 7492. The Final Rule included a federal implementation plan ("FIP") establishing Best Available Retrofit Technology ("BART") emission limitations on sulfur dioxide ("SO_2") for Units 3 and 4 of PSO's Northeastern plant ("PSO's Units") to address the visibility and interstate transport provisions of the CAA.

C. PSO desires to develop and implement a comprehensive strategy to comply with its obligations with respect to the visibility and interstate transport provisions of the CAA as well as its other obligations with respect to the CAA in a coordinated manner.

D. PSO intends to install low NOx combustion technologies on both of its Units, retire one of its Units, and install and operate on its other Unit a dry sorbent injection system and baghouse in order to achieve emissions rates that comply with the terms of this Agreement and with its obligations with respect to the visibility provisions of the CAA.

E. PSO intends to retire one of its Units and install and operate on its other Unit a dry sorbent injection system, a baghouse, and activated carbon injection to achieve emissions rates that comply with the Mercury & Air Toxics Standard that became effective April 16, 2012, 40 C.F.R. § 63.9984 ("the MATS Rule"). Properly designed and operated air pollution control systems consisting of dry sorbent injection system, baghouse, and activated carbon injection can achieve the MATS Rule emission limits. An EPA letter to the ODEQ and PSO dated July 18, 2012, expresses EPA's support of PSO's comprehensive strategy to use the technologies described in the Regional Haze Agreement referenced in Attachment A to this Agreement to achieve the emission limitations prescribed by the MATS Rule. The letter is attached to this Agreement as Attachment B.

F. On February 24, 2011, PSO timely filed a Petition for Review, challenging the issuance of the Final Rule in *Public Service Company of Oklahoma v. U.S. Environmental Protection Agency*, *et al.*, No. 12-9524. On March 26, 2012, Sierra Club filed a timely motion to intervene. The motion was granted March 27, 2012.

G. The CAA and EPA's regulations require States to develop SIPs to implement the CAA's provisions, including the CAA's visibility and interstate transport provisions. *See* 42 U.S.C. §§ 7410(a)(2)(D)(i)(II), (J), 7491(b)(2); 40 C.F.R. § 50.300(a). ODEQ is the administrative agency in the State of Oklahoma responsible for developing and proposing such SIPs. *See* 27A O.S. §§ 2-5-105(3), (20), 1-3-101(B)(8), 2-3-101(B)(2). The Secretary, as the Governor's designee for the State of Oklahoma, is responsible for submitting SIPs to EPA for review. *See* 40 C.F.R. Part 51, Appendix V, Section 2.1(a); 40 C.F.R. § 51.103(a). Because this Agreement requires ODEQ to develop and propose and the Secretary to submit SIP revisions to EPA under the visibility and interstate transport provisions of the CAA, and ODEQ and the Secretary prefer to regulate PSO under such SIP revisions rather than EPA's FIP, ODEQ and the Secretary have an interest in and are essential parties to this Settlement Agreement.

H. The Parties have negotiated in good faith and have determined that the settlement reflected in this Agreement is in the public interest. If approved and implemented as set forth herein, this Agreement will resolve PSO's Petition for Review.

I. This Agreement will not impact any other provisions of the Final Rule, and/or any other applicable federal, state, and local laws and regulations. No other claims will be affected by the resolution of the issues related to PSO's Units as set forth herein.

AGREEMENT

1. PSO, Sierra Club, and EPA agree that within ten (10) days after this Agreement is executed by the Parties (i.e., signed), but before finalization pursuant to Paragraph 16 of this Agreement, they will jointly move the Court for an order holding in abeyance PSO's Petition for Review pending implementation of the terms of the Agreement.

2. Within thirty (30) days of the effective date of this Agreement, PSO shall submit to ODEQ final and complete versions of all information and documentation (including technical supporting documentation for PSO's Units) necessary for the development of the SIP revisions referenced in Paragraphs 3 and 4.

3. No later than one hundred-twenty (120) days after PSO provides ODEQ with the information and documentation required in Paragraph 2, ODEQ will develop and propose a SIP revision under the visibility provisions of the CAA, 42 U.S.C. § 7491, and EPA's regional haze regulations, 40 C.F.R. § 51.308, that addresses PSO's Units ("Regional Haze SIP revision") in accordance with the provisions of Attachment A.

4. No later than one hundred-twenty (120) days after PSO provides ODEQ with the information and documentation required in Paragraph 2, ODEQ will develop and propose

a SIP revision under the interstate transport provisions of the CAA, 42 U.S.C. § 7410(a)(2)(D)(i)(II), that addresses PSO's Units ("Interstate Transport SIP revision") in accordance with the provisions of Attachment A.

5. No later than one hundred-twenty (120) days after PSO provides ODEQ with the information and documentation required in Paragraph 2, the Secretary shall provide the proposed SIP revisions required in Paragraphs 3 and 4 to EPA and request parallel processing of the SIP revisions from EPA pursuant to 40 C.F.R. Part 51, App. V, Section 2.3.

6. If ODEQ determines, at any time subsequent to PSO's submittal of all information and documentation for PSO's Units as required in Paragraph 2, that additional information and/or documentation is necessary in order to develop the SIP revisions referenced in Paragraphs 3 and 4, ODEQ shall provide PSO with a written request for such additional information and/or documentation with a copy to all Parties. The deadlines associated with the obligations under Paragraphs 3-5 of this Agreement shall be tolled during the period of time between the issuance of the written request and ODEQ's receipt of the requested information and/or documentation.

7. After the opportunity for public hearing and the close of Oklahoma's notice-and-comment period for the Regional Haze and Interstate Transport SIP revisions, but no later than ninety (90) days after the Secretary submits the request for parallel processing referenced in Paragraph 5, ODEQ will consider and if appropriate adopt the Regional Haze and Interstate Transport SIP revisions referred to in Paragraphs 3 and 4. If adopted, the Secretary will submit to EPA those SIP revisions.

8. The Regional Haze and Interstate Transport SIP revisions adopted and submitted to EPA under Paragraph 7 will include the provisions described in Attachment A to this Agreement unless the Parties, by written mutual agreement, amend the provisions described in Attachment A. If the Regional Haze and Interstate Transport SIP revisions adopted and submitted to EPA by the Secretary do not include the provisions described in Attachment A to this Agreement, PSO may file a motion to dissolve the stay of PSO's petition for review and request that a briefing schedule be set. PSO may also pursue any opportunities for administrative or judicial review of the Regional Haze and Interstate Transport SIP revisions adopted by ODEQ and submitted by the Secretary.

9. Within sixty (60) days of EPA's receipt of the final Regional Haze and Interstate Transport SIP revisions EPA will determine whether the revisions meet the requirements of the CAA consistent with 42 U.S.C. § 7410(k)(1)(B) ("completeness finding").

10. EPA will take final action on the Regional Haze and the Interstate Transport SIP revisions as soon as possible, but no later than six (6) months from the date of the completeness finding referred to in Paragraph 9 consistent with 42 U.S.C. § 7410(k)(2).

11. If EPA promulgates a final action approving the provisions of the Regional Haze and Interstate Transport SIP revisions included in Attachment A, as adopted and submitted to

EPA by Oklahoma, PSO, the Sierra Club, and EPA will promptly file a joint stipulation of dismissal of PSO's Petition for Review. The Parties agree that they will not challenge that portion of any final action issued by EPA that fully approves the Regional Haze and Interstate Transport SIP revisions as adopted and submitted to EPA by the Secretary that contain the provisions in Attachment A affecting PSO's Units.

12. Separately from the SIP process, PSO will report biannually to EPA (beginning in 2017 for the period 2015-2016, and every second year thereafter through the end of 2025 or 2026, whenever the last Northeastern unit is retired) on the energy produced by PSO's units and the sources of energy secured under PSO's long-term purchased power contracts. The initial report will include similar information for calendar years 2013-2014. Requests for proposals ("RFPs") for long-term purchase power contracts issued between 2013 and the date the reporting obligation ends will specifically seek bids for energy supplied by natural gas and renewable resources. The biannual reports will include copies of any RFPs issued during the reporting period, and a summary of the capacity or energy secured through any long-term power purchase agreements executed during the reporting period, including the unit(s) providing the purchased power, the amount of capacity or energy secured under the agreement, and the term of each agreement.

13. The Parties may, by written mutual agreement, extend the dates in Paragraphs 2-5, 7, and 9-10 by which actions must be taken to fulfill the Parties' respective obligations under this Agreement.

14. Nothing in the Regional Haze and Interstate Transport SIP revisions as adopted and submitted to EPA by Oklahoma or in this Agreement shall relieve PSO from its obligations to comply with all applicable federal, state, and local laws and regulations, including laws, regulations, and compliance deadlines that become applicable after the date of any revisions to Oklahoma's Regional Haze SIP that may be approved by EPA. Such laws and regulations include, but are not limited to, any EPA rule imposing requirements relevant to interstate transport under 42 U.S.C. § 7410(a)(2)(D) and the MATS Rule. Nothing in Oklahoma's Regional Haze SIP revision, including the BART determination for PSO's Units, should be construed to provide any relief from the emissions limits or deadlines specified in such regulations, including, but not limited to, deadlines for the installation of pollution controls required by any such regulations.

15. If EPA does not take final action approving those aspects of the Regional Haze and Interstate Transport SIP revisions that contain the provisions of Attachment A, as adopted and submitted to EPA by Oklahoma, PSO may file a motion to dissolve the stay of PSO's Petition for Review, and to request that a briefing schedule be set. EPA does not waive or limit any defense relating to such litigation. This shall be the only remedy for EPA's failure to fulfill its obligations under this Agreement. PSO and Sierra Club agree that contempt of court is not an available remedy under this Agreement.

16. The Parties agree and acknowledge that before this Agreement is final, EPA must provide notice in the Federal Register and an opportunity for public comment pursuant to CAA

section 113(g), 42 U.S.C. § 7413(g). EPA shall promptly submit said notice of this Agreement to the Federal Register after this Agreement is executed by the Parties (i.e., signed). After this Agreement has undergone an opportunity for notice and comment, the Administrator or the Attorney General, as appropriate, shall promptly consider any such written comments in determining whether to withdraw or withhold their consent to the Agreement, in accordance with section 113(g) of the CAA.
If the United States elects not to withdraw or withhold its consent to this Agreement, EPA shall provide written notice to the Parties as expeditiously as possible. This Agreement shall become final and effective on the date that EPA provides such written notice to the Parties. If EPA does not provide such written notice within sixty (60) days after the notice of the Agreement is published in the Federal Register, the sole remedy shall be the right to file a motion to dissolve the stay of the Petition for Review, and to request that a briefing schedule be set. EPA does not waive or limit any defense relating to such litigation. PSO and Sierra Club agree that contempt of court is not an available remedy under this Agreement.

17. No provision of this Agreement shall be interpreted as or constitute a commitment or requirement that the United States or any of its departments or agencies obligate or pay funds in contravention of the Anti-Deficiency Act, 31 U.S.C. § 1341 *et seq.*, or in violation of any other statue, law, or regulation.

18. Nothing in this Agreement shall be construed to limit or modify the discretion accorded to EPA, ODEQ, or the Secretary by statute, or by general principles of administrative law.

19. Nothing in this Agreement shall be construed to limit or modify the rights of PSO or Sierra Club to seek reconsideration or judicial review of any altered, amended or revised provisions of any final action that ODEQ or EPA may take that differ in any material respect from the provisions described in Attachment A (or as amended by mutual written agreement of the Parties pursuant to Paragraph 8).

20. The undersigned hereby certify that they are duly authorized to bind the Party on whose behalf this Agreement is executed to the terms of this Agreement.

21. The provisions of this Agreement shall apply to and be binding on the Parties, their successors and assigns.

22. This Agreement may be signed in counterparts, and such counterpart signatures shall be given full force and effect.

FOR PETITIONER PSO:

Dated: 10-17-12

J. Stuart Solomon

J. Stuart Solomon, President
Public Service Company of Oklahoma

FOR STATE OF OKLAHOMA:
SECRETARY OF THE ENVIRONMENT FOR
THE STATE OF OKLAHOMA

Dated: 10/1/12

FOR OKLAHOMA DEPARTMENT OF
ENVIRONMENTAL QUALITY:

Dated: 9-28-12

FOR U.S. ENVIRONMENTAL PROTECTION AGENCY:

IGNACIA S. MORENO
Assistant Attorney General
Environment and Natural Resources Division

Dated:__________ By: ____

STEPHANIE J. TALBERT
Environmental Defense Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. BOX 7611
Washington, DC 20044
(202) 514-2617
Fax: (202) 514-8865
Stephanie.Talbert@usdoj.gov

FOR INTERVENOR SIERRA CLUB:

Dated: 10/16/12 ______________________________

<u>ATTACHMENT A</u>

1. Oklahoma, through the Secretary, will submit to EPA a Regional Haze SIP revision that addresses PSO's Units and includes, among other things, the following elements:

   a. Oklahoma's SIP revision will include a Regional Haze Agreement ("RHA") entered into by ODEQ and PSO to effectuate the BART determination.

   b. The RHA will require that by no later than December 31, 2013, PSO will complete installation of low NOx combustion technologies and achieve a nitrogen oxide ("NOx") emission rate of 0.23 lb/MMBtu on a 30-day rolling average at each of PSO's Units.

   c. The RHA will require that beginning on January 31, 2014, PSO will comply with a new SO_2 emission rate at each of PSO's Units of 0.65 lb/MMBtu on a 30-day rolling average, and beginning on December 31, 2014, PSO will comply with a new SO_2 emission rate of 0.60 lb/MMBtu on a 12-month rolling average at each of PSO's Units. PSO will maintain those emission rates until controls are installed at one unit as provided in subparagraph (e), and the other unit is retired as provided in subparagraph (d). The RHA will include an alternative operating scenario that addresses potential service disruption of coal supplies during the time period between January 31, 2014 through April 16, 2016.

   d. The RHA will require that PSO seek all necessary regulatory approvals, and will retire one of the coal-fired generating units at Northeastern Station by April 16, 2016.

   e. The RHA will require that PSO seek all necessary regulatory approvals, and install and operate a dry-sorbent injection system, activated carbon injection system, and a fabric filter baghouse, and secure further NOx emission reductions by April 16, 2016 on the coal-fired generating unit at Northeastern Station that will continue to operate. After completion of the installation of the pollution controls required by this subparagraph, PSO will achieve a 0.15 lb/MMBtu emission rate for NOx on a 30-day rolling average basis, and a 0.40 lb/MMBtu emission rate for SO_2 on a 30-day rolling average basis.

   f. The RHA will require that during the first year of operation of the controls required under the RHA, PSO will develop and propose a monitoring program to test various operating profiles and other measures, to determine whether increased SO_2 removal efficiencies can be achieved during normal operations. Pursuant to the terms of the RHA, PSO will submit the monitoring program to EPA and ODEQ for review and will implement the monitoring program during the second and third years of operation of the dry sorbent injection system. PSO will evaluate and report the results of the monitoring program to EPA and ODEQ, and if that evaluation demonstrates that the technology is capable of sustainably achieving an emission rate of less than 0.37 lbs/MMBtu on a 30-day rolling average basis without (i) altering the unit's fuel supply, (ii) incurring additional capital costs, (iii) increasing operating expenses by more than a negligible amount, and/or (iv) adversely impacting overall unit operations, ODEQ will propose to revise the emission rate in the RHA by 60 percent of the difference between 0.40 and the demonstrated emission rate. Upon adoption after notice and opportunity for hearing, Oklahoma, through the Secretary, will submit a Regional Haze SIP revision to EPA for approval. If the demonstrated emission rate is 0.37 lbs/MMBtu or greater, no adjustment will be made to the RHA, and the emission rate from the operating Northeastern coal-fired generating unit in the RHA will remain 0.40 lbs/MMBtu.

g. The RHA will require that beginning in calendar year 2021, the Annual Capacity Factor (calculated for each calendar year as a percentage of MWH based on a rated capacity of 470 MW times 8760 hours) for the operating coal-fired generating unit at Northeastern Station will be reduced as follows:
    i. to no more than 70 percent in calendar years 2021 and 2022;
    ii. to no more than 60 percent in calendar years 2023 and 2024; and
    iii. to no more than 50 percent in calendar years 2025 and 2026.

h. The RHA will require that no later than December 31, 2026, PSO will retire the remaining operating coal-fired generating unit at Northeastern Station. However, in calendar year 2021, the RHA will require PSO to evaluate whether the projected generation from that unit can be replaced at lower or equal total projected costs from natural gas or renewable resources. Pursuant to the RHA, PSO will provide a copy of the evaluation to EPA and ODEQ. If power is available from such resources at a lower projected total cost (including consideration of PSO's need to recover its remaining investment in the units), then the operating unit will retire no later than December 31, 2025.

2. Oklahoma, through the Secretary, will submit to EPA an Interstate Transport SIP revision that addresses PSO's Units and includes, among other things, the following elements:

a. An enforceable mechanism that addresses SO_2 reductions from sources other than those operated by PSO, to the extent necessary to achieve the anticipated visibility benefits from the 2018 regional modeling; and

b. A provision requiring that the enforceable mechanism referred to in Paragraph 2(a) of this Attachment A be implemented if the SO_2 emission rate for the controlled unit at Northeastern is not reduced to 0.30 lbs/MMBtu or less as a result of the Paragraph 1(f) of this Attachment A.

120 East Sheridan | Suite 205 | Oklahoma City, OK 73104 | P (405) 228-3292 | F (918) 512-7084
trinityconsultants.com

Trinity Consultants

October 3, 2012

Ms. Lee Warden, P.E.
Supervisor, Engineering Section
Air Quality Division
Oklahoma Department of Environmental Quality
707 N. Robinson
Oklahoma City, OK 73101

Re: BART Resubmittal Modeling Protocol
Northeastern Power Station
American Electric Power (AEP) / Public Service Company of Oklahoma (PSO)

Dear Ms. Warden:

Trinity is pleased to submit the attached CALPUFF Modeling Protocol on behalf of American Electric Power (AEP) and the Public Service Company of Oklahoma (PSO). This protocol is submitted in response to the request for reconsideration and resubmittal of the Best Available Retrofit Technology (BART) determinations at the Northeastern Power Station by the Oklahoma Department of Environmental Quality (ODEQ) and the Environmental Protection Agency (EPA). AEP/PSO requests formal approval from ODEQ of the CALPUFF Modeling Protocol prior to the commencement of modeling efforts and submission of results. Also included with this submittal is a copy of the met data set to be used in conjunction with the current modeling efforts.

The BART modeling efforts will follow the procedures outlined in the enclosed CALPUFF Modeling Protocol. This protocol proposes to follow the same modeling procedures that were used in the original 2008 modeling, with the exception of the following four updates:

- The postprocessor POSTUTIL (Version 1.52, Level 060412) will be used to repartition nitrates from the CALPUFF output file to be consistent with the total available sulfate and ammonia, prior to assessing visibility with CALPOST.
- The CALPOST model version will be updated to Version 6.221, Level 080724.
- The CALPOST visibility calculation method will be updated from Method 6 to Method 8. 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.
- The annual average background concentrations used in the CALPOST models for each of the four Class I Areas of interest (Caney Creek Wilderness, Hercules Glades Wilderness, Upper Buffalo Wilderness, and Wichita Mountains Wilderness) will be updated based on values found in the 2010 FLAG guidance.

If you have any questions or need additional information, please call me at (405) 228-3292 or Howard L. "Bud" Ground of PSO at (405) 841-1322.

Sincerely,

TRINITY CONSULTANTS

Jeremy Townley
Senior Consultant

Encl: CALPUFF Modeling Protocol

CALPUFF Modeling Protocol
Best Available Retrofit Technology (BART) Determination
American Electric Power ■ Northeastern Power Plant

Prepared by:

Jeremy W. Jewell ▪ Manager of Consulting Services
Jeremy Townley ▪ Senior Consultant
Kara Gerlach ▪ Consultant

Trinity Consultants
120 East Sheridan
Suite 205
Oklahoma City, OK 73104
(405) 228-3292

October 3, 2012

Project 123701.0079

AEP AMERICAN ELECTRIC POWER

Trinity Consultants

CALPUFF MODELING PROTOCOL
BEST AVAILABLE RETROFIT TECHNOLOGY (BART) DETERMINATION
AMERICAN ELECTRIC POWER ■ NORTHEASTERN POWER PLANT

Prepared by:

Jeremy W. Jewell ▪ Manager of Consulting Services
Jeremy Townley ▪ Senior Consultant
Kara Gerlach ▪ Consultant

TRINITY CONSULTANTS
120 East Sheridan
Suite 205
Oklahoma City, OK 73104
(405) 228-3292

October 3, 2012

Project 123701.0079

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1. INTRODUCTION

American Electric Power /Public Service Company of Oklahoma (AEP/PSO) operates the Northeastern Power Station, which is located at Section 4, T22N, R15E, in Rogers County, Oklahoma. The Northeastern Power Station is currently operating in accordance with Oklahoma Department of Environmental Quality (DEQ) Title V Operating Permit, 2003-410-TVR (M-2), issued in August 24, 2010. The Northeastern Power Station is considered eligible for the application of Best Available Retrofit Technology (BART) as part of the Environmental Protection Agency (EPA) Regional Haze Rule. This protocol describes the proposed methodology for conducting the CALPUFF BART modeling analysis for the AEP Northeastern Power Station. The protocol also includes a discussion of the post processing methodologies to be used in the refined modeling analysis for the Northeastern Power Station.

1.1 OBJECTIVE

The objective of this document is to provide a protocol summarizing the modeling methods and procedures that will be followed to complete a refined CALPUFF modeling analysis for the Northeastern Power Station. The modeling methods and procedures contained in this protocol will be used to determine appropriate controls for AEP's BART-eligible sources that can reasonably be anticipated to reduce the sources' effects on or contribution to visibility impairment in the surrounding Class I areas.

1.2 LOCATION OF SOURCES AND RELEVANT CLASS I AREAS

The sources listed in Table 1-1. BART-Eligible Sources are the sources that have been identified by AEP as sources that meet the three criteria for BART-eligible sources at the Northeastern Power Station.

TABLE 1-1. BART-ELIGIBLE SOURCES

EPN	Description
Unit 2	4,754 MMBtu/hr Gas-fired
Unit 3	4,775 MMBtu/hr Coal Fired Boiler
Unit 4	4,775 MMBtu/hr Coal Fired Boiler

As required in CENRAP's BART Modeling Guidelines, Class I areas within 300 km of each station will be included in each analysis. The following tables summarize the distances of the four closest Class I areas to the Northeastern Power Station. As seen from this summary, one Class I area (Wichita Mountains) is more than 300 km from the station, but has been included in the analysis. Note that the distances listed in the tables below are the distances between the station~~s~~ and the closest border of the Class I areas.

TABLE 1-2. DISTANCE (KM) FROM STATION TO SURROUNDING CLASS I AREAS

Class I Area Name	Distance from Source (km)
Caney Creek Wilderness	263
Hercules-Glades Wilderness	244
Upper Buffalo Wilderness	211
Wichita Mountains Wilderness	323

The main components of the CALPUFF modeling system are CALMET, CALPUFF, and CALPOST. CALMET is the meteorological model that generates hourly three-dimensional meteorological fields such as wind and temperature. CALPUFF simulates the non-steady state transport, dispersion, and chemical transformation of air pollutants emitted from a source in "puffs." CALPUFF calculates hourly concentrations of visibility affecting pollutants at each specified receptor in a modeling domain. CALPOST is the post-processor for CALPUFF that computes visibility impacts from a source based on the visibility affecting pollutant concentrations that were output by CALPUFF.

Other components of the CALPUFF modeling system include geophysical data processors such as TERREL, CTGCOMP, CTGPROC, and MAKEGEO. These processors create a geophysical data file from land use and terrain data, which is then used in the CALMET model. Another important processor in the CALPUFF modeling system is the postprocessor POSTUTIL. POSTUTIL is used to repartition nitrates from the CALPUFF output file to be consistent with the total available sulfate and ammonia, prior to assessing visibility with CALPOST.

2.1 MODEL VERSIONS

The versions of the CALPUFF modeling system programs that will be used for conducting AEP's BART modeling are listed in Table 2-1.

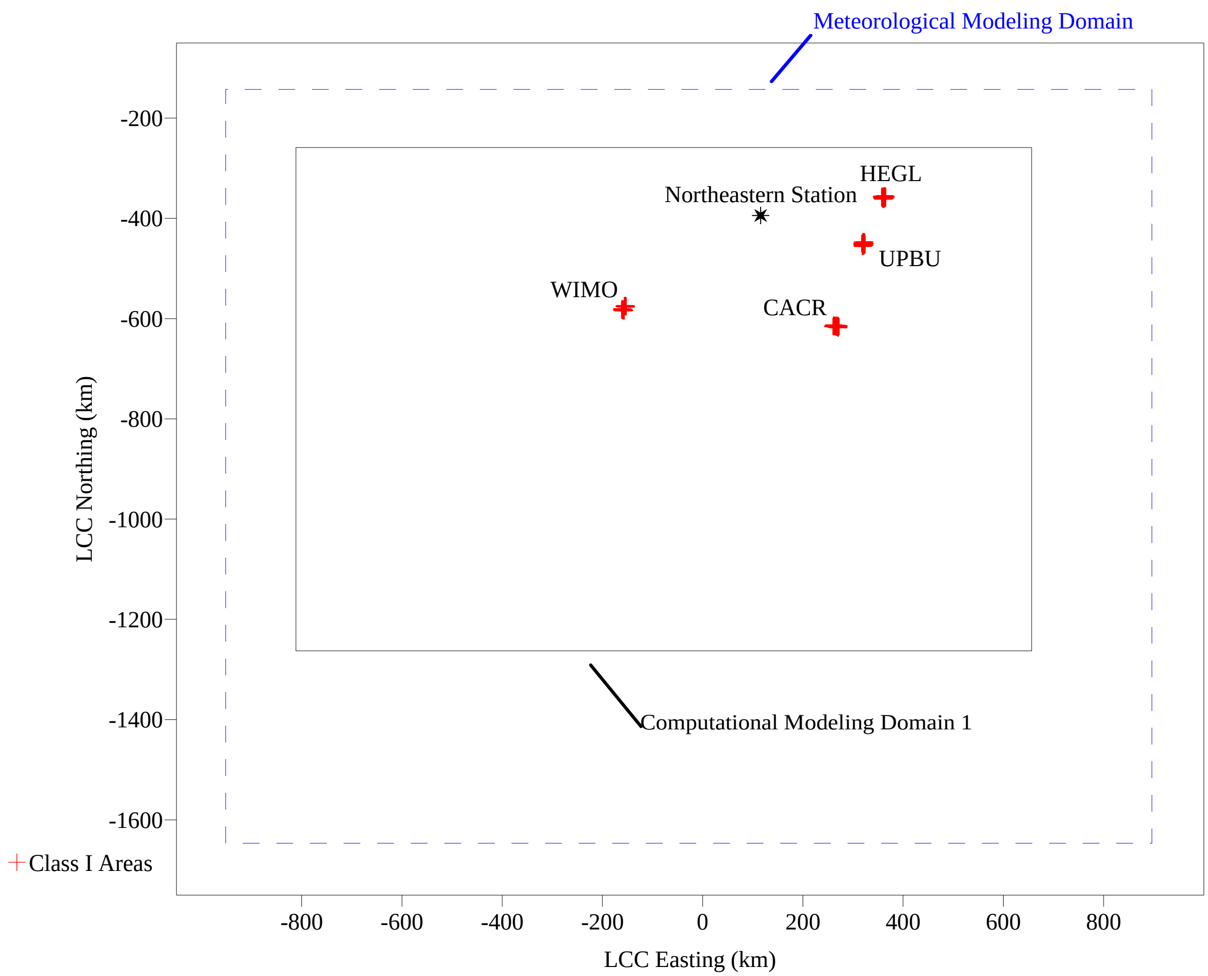
TABLE 2-1. CALPUFF MODELING SYSTEM VERSIONS

Processor	Version	Level
TERREL	3.3	030402
CTGCOMP	2.21	030402
CTGPROC	2.63	050128
MAKEGEO	2.2	030402
CALMET	5.53a	040716
CALPUFF	5.8	070623
POSTUTIL	1.52	060412
CALPOST	6.221	080724

2.2 MODELING DOMAIN

The CALPUFF modeling system utilizes three modeling grids: the meteorological grid, the computational grid, and the sampling grid. The meteorological grid is the system of grid points at which meteorological fields are developed with CALMET. The computational grid determines the computational area for a CALPUFF run. Puffs are advected and tracked only while within the computational grid. The meteorological grid is defined so that it covers the areas of concern and gives enough marginal buffer area for puff transport and dispersion. A plot of the meteorological modeling domain with respect to the Class I areas being modeled is provided in Figure 2-1. The computational domain will be set to extend at least 50 km in all directions beyond the Northeastern Power Station and the Class I areas of interest. Note that the map projection for the modeling domain will be Lambert Conformal Conic (LCC) and the datum will be the World Geodetic System 84 (WGS-84). The reference point for the modeling domain is Latitude 40ºN, Longitude 97ºW. The southwest corner will be set to -951.547 km LCC, -1646.637 km LCC corresponding to Latitude 24.813 ºN and Longitude 87.778ºW. The meteorological grid spacing will be 4 km, resulting in 462 grid points in the X direction and 376 grid points in the Y direction.

FIGURE 2-1. REFINED METEOROLOGICAL MODELING DOMAIN



3. CALMET

The EPA Approved Version of the CALMET meteorological processor will be used to generate the meteorological data for CALPUFF. CALMET is the meteorological processor that compiles meteorological data from raw observations of surface and upper air conditions, precipitation measurements, mesoscale model output, and geophysical parameters into a single hourly, gridded data set for input into CALPUFF. CALMET will be used to assimilate data for 2001- 2003 using National Weather Service (NWS) surface station observations, upper air station observations, precipitation station observations, buoy station observations (for overwater areas), and mesoscale model output to develop the meteorological field.

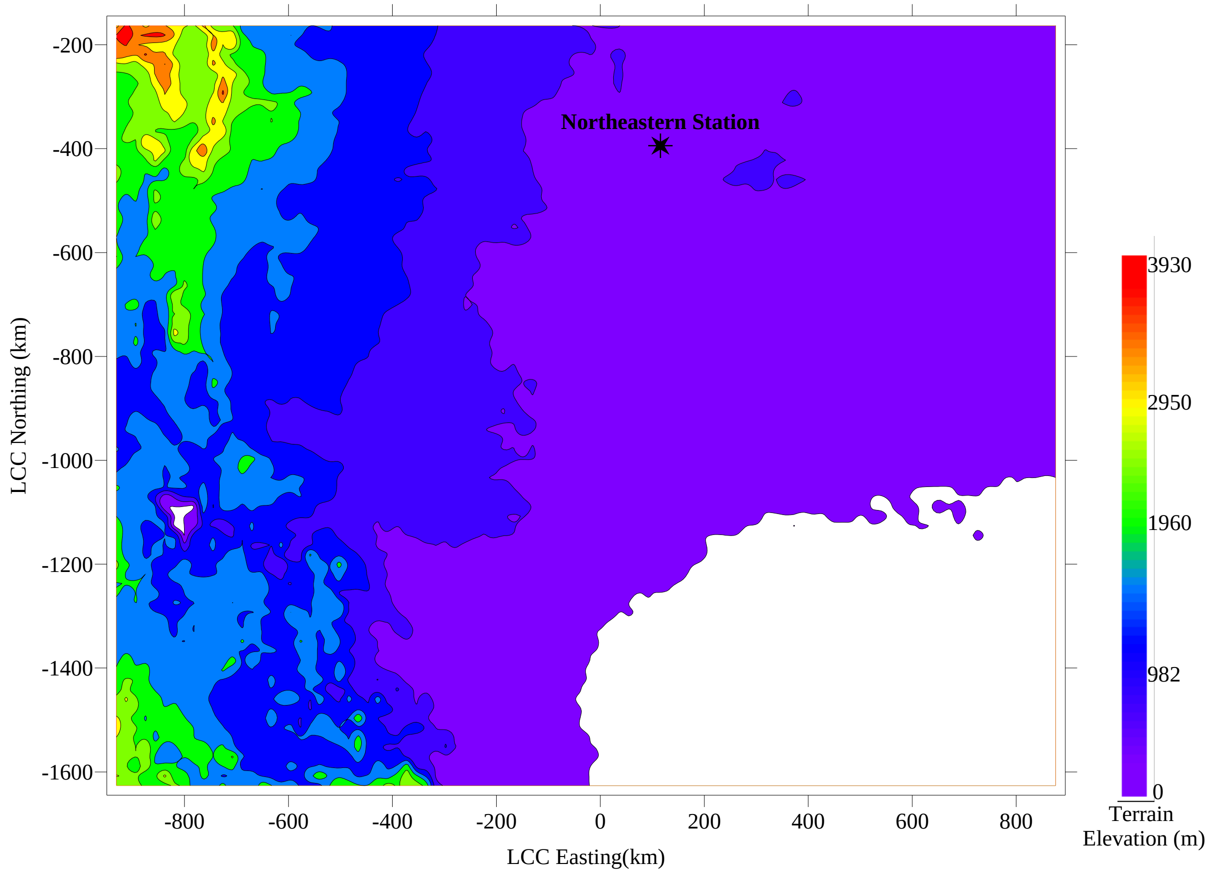
3.1 GEOPHYSICAL DATA

CALMET requires geophysical data to characterize the terrain and land use parameters that potentially affect dispersion. Terrain features affect flows and create turbulence in the atmosphere and are potentially subjected to higher concentrations of elevated puffs. Different land uses exhibit variable characteristics such as surface roughness, albedo, Bowen ratio, and leaf-area index that also effect turbulence and dispersion.

3.1.1 TERRAIN DATA

Terrain data will be obtained from the United States Geological Survey (USGS) in 1-degree (1:250,000 scale or approximately 90 meter resolution) digital format. The USGS terrain data will then processed by the TERREL program to generate grid-cell elevation averages across the modeling domain. A plot of the land elevations based on the USGS data for the modeling domain is provided in Figure 3-1.

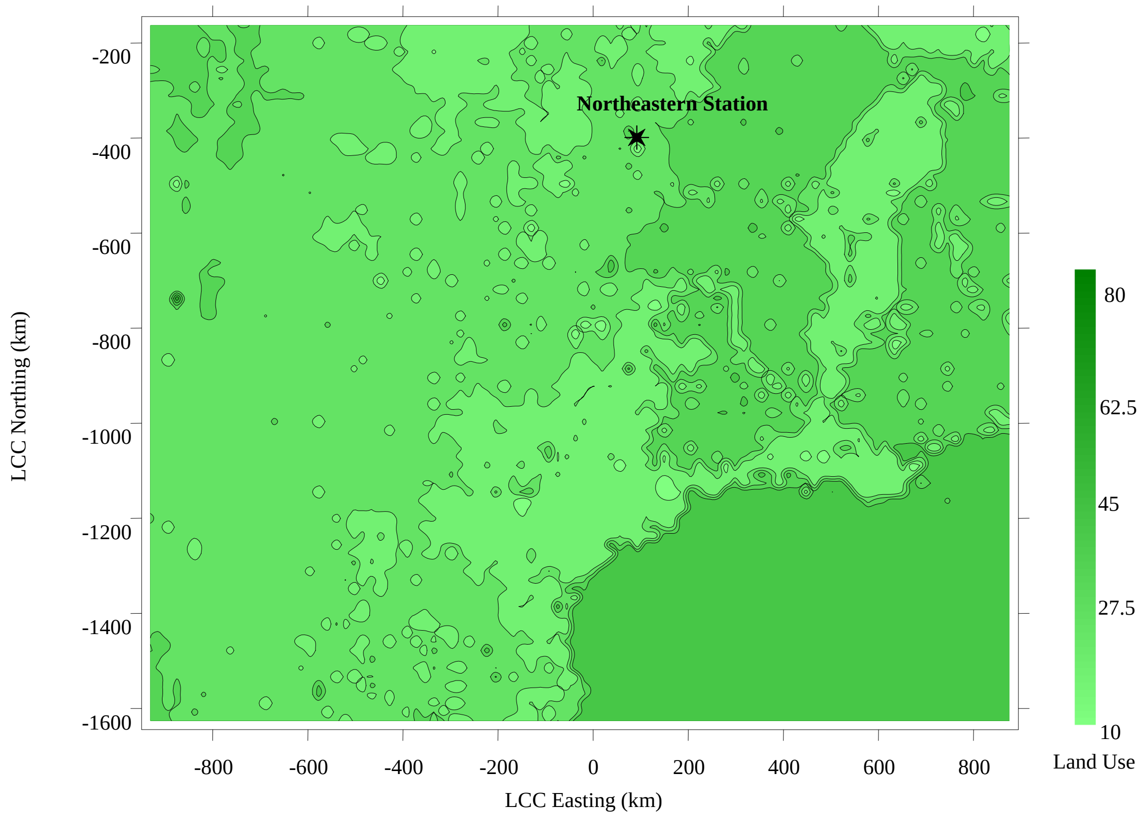
FIGURE 3-1. PLOT OF LAND ELEVATION USING USGS TERRAIN DATA



3.1.2 LAND USE DATA

The land use land cover (LULC) data from the USGS North American land cover characteristics data base in the Lambert Azimuthal equal area map projection will be used in order to determine the land use within the modeling domain. The LULC data will be processed by the CTGPROC program which generated land use for each grid cell across the modeling domain. A plot of the land use based on the USGS data for the modeling domain is provided in Figure 3-2.

FIGURE 3-2. PLOT OF LAND USE USING USGS LULC DATA



3.1.3 COMPILING TERRAIN AND LAND USE DATA

The terrain data files output by the TERELL program and the LULC files output by the CTGPROC program will be uploaded into the MAKEGEO program to create a geophysical data file that will be input into CALMET.

3.2 METEOROLOGICAL DATA

CALMET will be used to assimilate data for 2001, 2002, and 2003 using mesoscale model output and National Weather Service (NWS) surface station observations, upper air station observations, precipitation station observations, and National Oceanic and Atmosphere Administrations (NOAA) buoy station observations to develop the meteorological field.

3.2.1 MESOSCALE MODEL METEOROLOGICAL DATA

Hourly mesoscale data will also be used as the initial guess field in developing the CALMET meteorological data. It is AEP's intent to use the following 5th generation mesoscale model meteorological data sets (or MM5 data) in the analysis:

- 2001 MM5 data at 12 km resolution generated by the U.S. EPA
- 2002 MM5 data at 36 km resolution generated by the Iowa DNR

- 2003 MM5 data set at 36 km resolution generated by the Midwest RPO

The specific MM5 data that will be used are subsets of the data listed above. As the contractor to CENRAP for developing the meteorological data sets for the BART modeling, Alpine Geophysics extracted three subsets of MM5 data for each year from 2001 to 2003 from the data sets listed above using the CALMM5 extraction program. The three subsets covered the northern, central, and southern portions of CENRAP. AEP is proposing to use the southern set of the extracted MM5 data.

The 2001 southern subset of the extracted MM5 data includes 30 files that are broken into 10 to 11 day increments (3 files per month). The 2002 and 2003 southern subsets of extracted MM5 data include 12 files each of which are broken into 30 to 31 day increment files (1 file per month). Note that the 2001 to 2003 MM5 data extracted by Alpine Geophysics will not be able to be used directly in the modeling analysis. To run the Alpine Geophysics extracted MM data in the EPA approved CALMET program, each of the MM5 files will need to be adjusted by appending an additional six (6) hours, at a minimum, to the end of each file to account for the shift in time zones from the Greenwich Mean Time (GMT) prepared Alpine Geophysics data to Time Zone 6 for this analysis. No change to the data will occur.

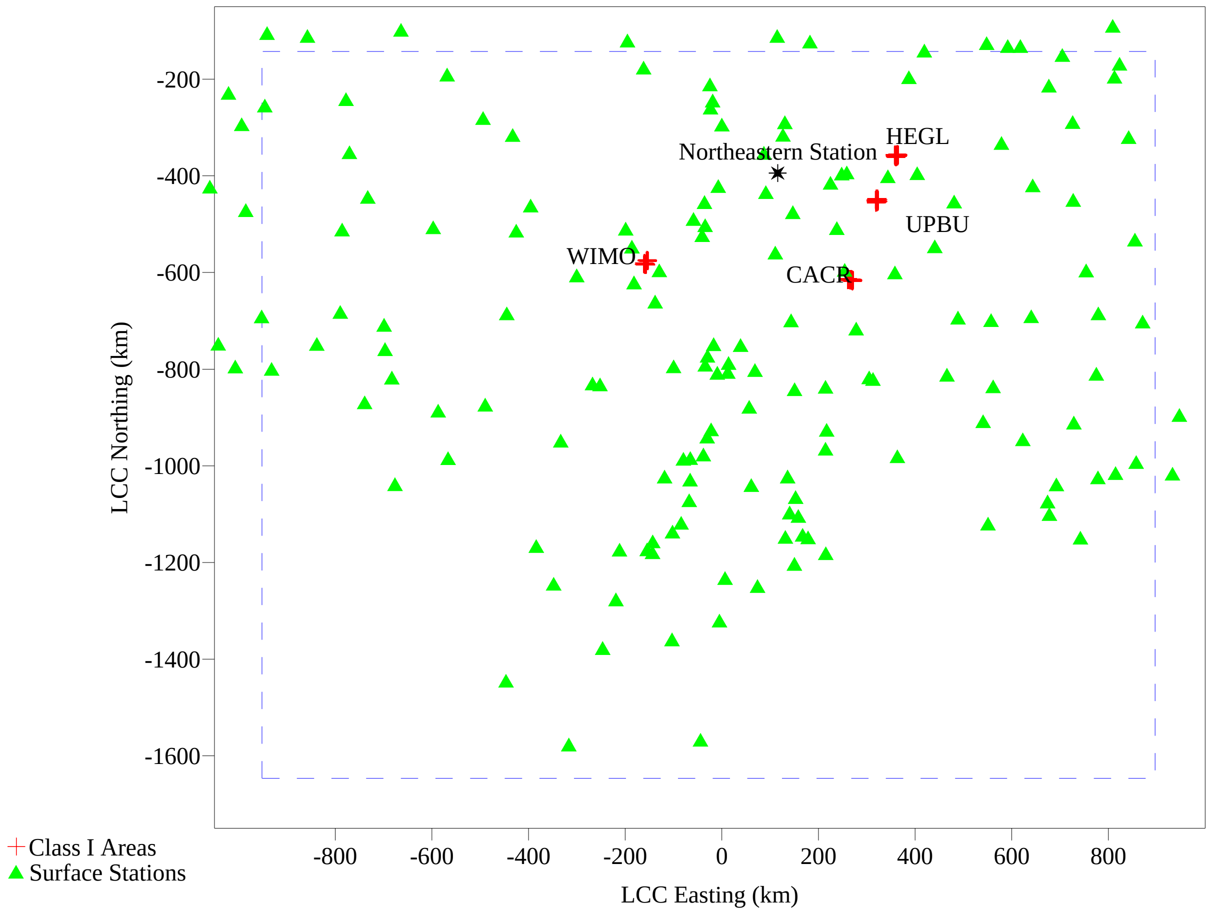
The time periods covered by the data in each of the MM5 files extracted by Alpine Geophysics include a specific number of calendar days, where the data starts at Hour 0 in GMT for the first calendar day and ends at Hour 23 in GMT on the last calendar day. In order to run CALMET in the local standard time (LST), which is necessary since the surface meteorological observations are recorded in LST, there must be hours of MM5 data referenced in a CALMET run that match the LST observation hours. Since the LST hours in Central Standard Time (CST) are 6 hours behind GMT, it is necessary to adjust the data in each MM5 file so that the time periods covered in the files match CST.

Based on the above discussion, the Alpine Geophysics MM5 data will not be used directly. Instead the data files will be modified to add 8 additional hours of data to the end of each file from the beginning of the subsequent file. CALMET will then be run using the appended MM5 data to generate a contiguous set of CALMET output files. The converted MM5 data files occupy approximately 1.2 terabytes (TB) of hard drive space.

3.2.2 SURFACE METEOROLOGICAL DATA

Parameters affecting turbulent dispersion that are observed hourly at surface stations include wind speed and direction, temperature, cloud cover and ceiling, relative humidity, and precipitation type. It is AEP's intent to use the surface stations listed in Table A-1 of Appendix A. The locations of the surface stations with respect to the modeling domain are shown in Figure 3-3. The stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's SMERGE program.

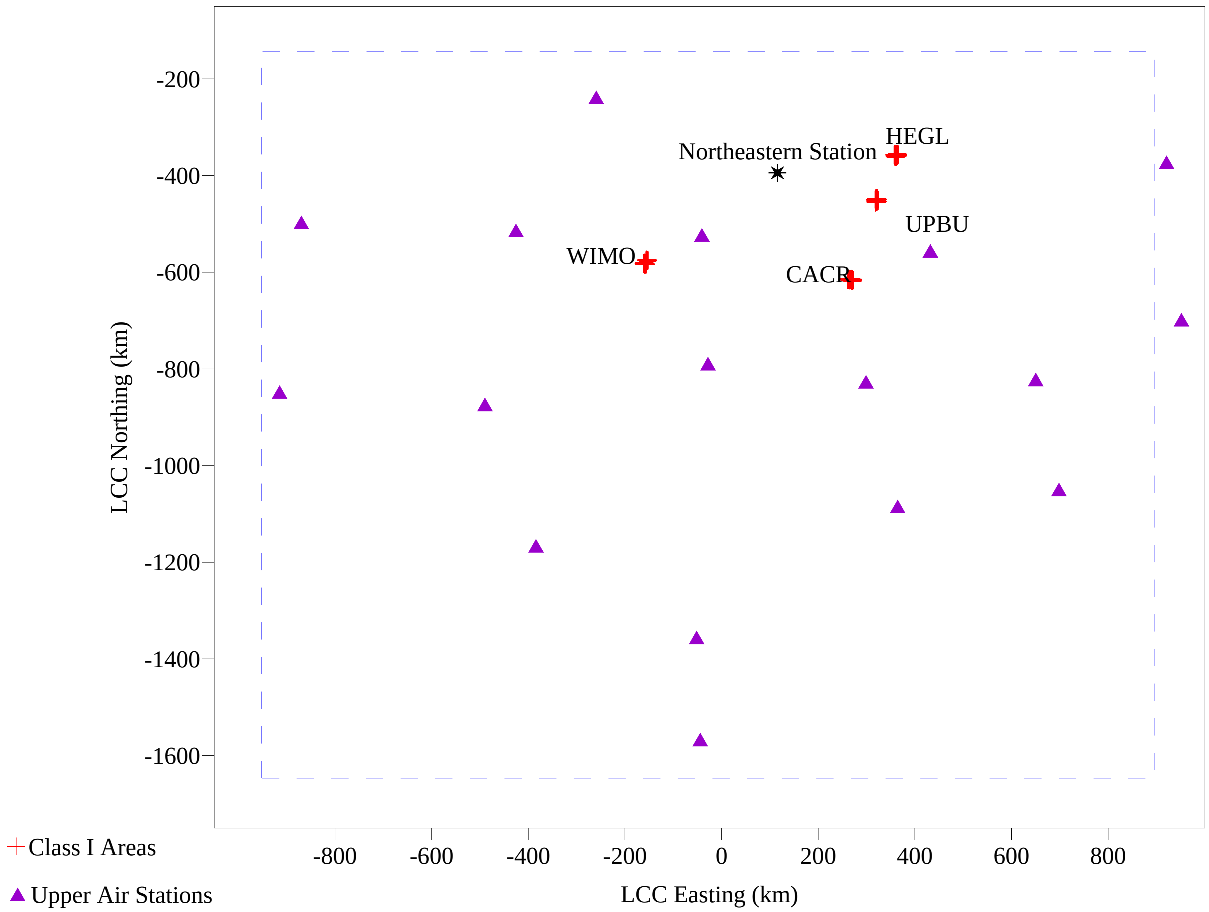
FIGURE 3-3. PLOT OF SURFACE STATION LOCATIONS



3.2.3 UPPER AIR METEOROLOGICAL DATA

Observations of meteorological conditions in the upper atmosphere provide a profile of turbulence from the surface through the depth of the boundary layer in which dispersion occurs. Upper air data are collected by balloons launched simultaneously across the observation network at 0000 Greenwich Mean Time (GMT) (6 o'clock PM in Oklahoma) and 1200 GMT (6 o'clock AM in Oklahoma). Sensors observe pressure, wind speed and direction, and temperature (among other parameters) as the balloon rises through the atmosphere. The upper air observation network is less dense than surface observation points since upper air conditions vary less and are generally not as affected by local effects (e.g., terrain or water bodies). The upper air stations that are proposed for this analysis are listed in Table A-2 of Appendix A. The locations of the upper air stations with respect to the modeling domain are shown in Figure 3-4. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's READ62 program.

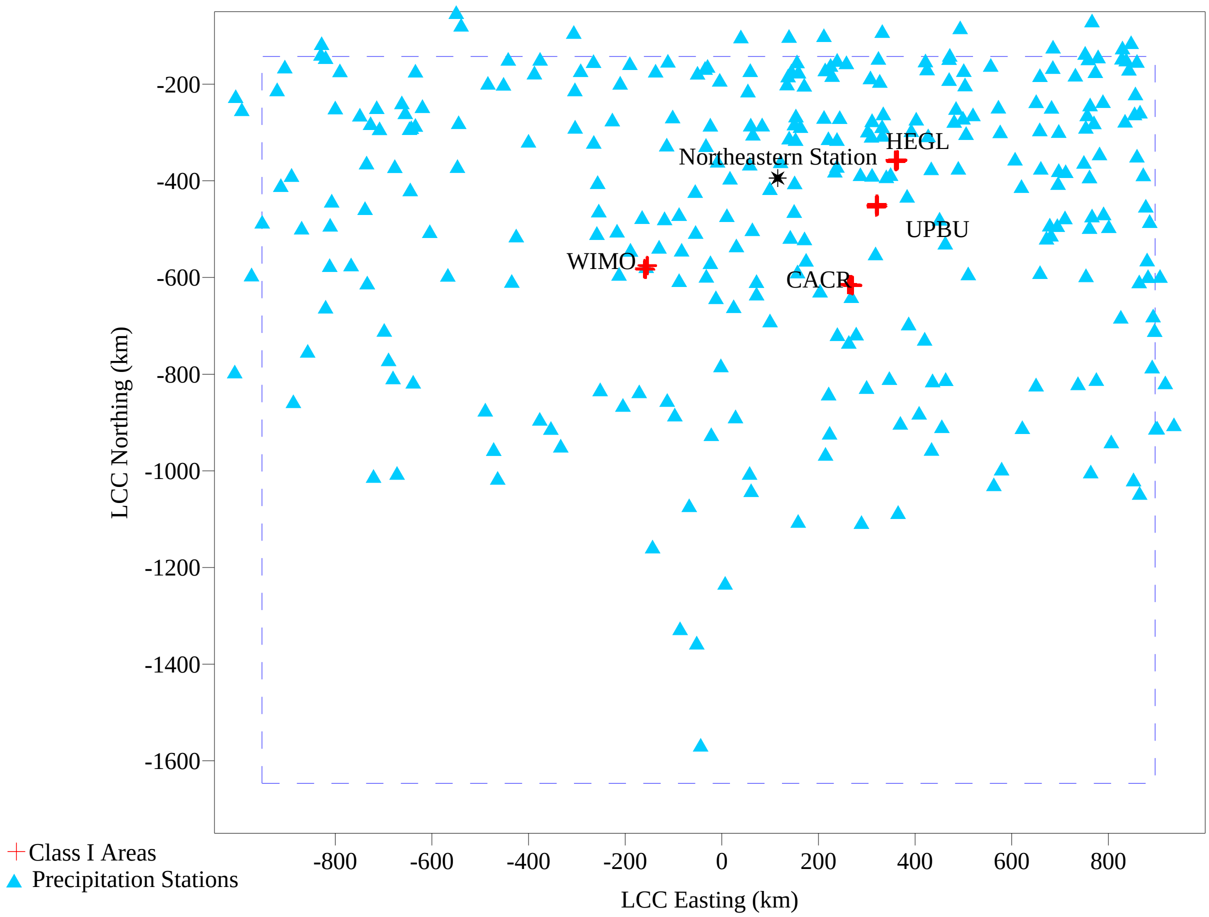
FIGURE 3-4. PLOT OF UPPER AIR STATIONS LOCATIONS



3.2.4 PRECIPITATION METEOROLOGICAL DATA

The effects of chemical transformation and deposition processes on ambient pollutant concentrations will be considered in this analysis. Therefore, it is necessary to include observations of precipitation in the CALMET analysis. The precipitation stations that are proposed for this analysis are listed in Table A-3 of Appendix A. The locations of the precipitation stations with respect to the modeling domain are shown in Figure 3-5. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's PMERGE program.

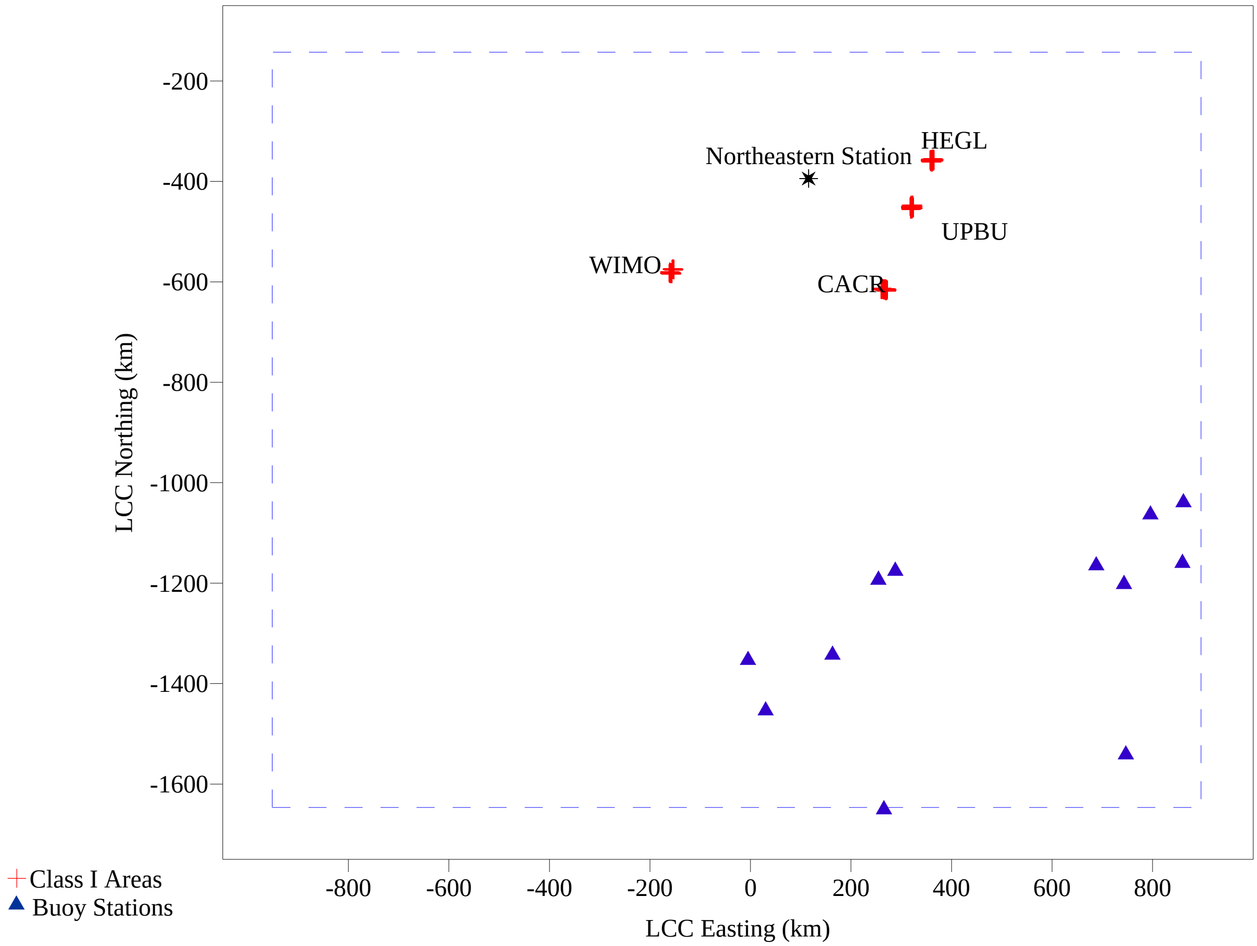
FIGURE 3-5. PLOT OF PRECIPITATION METEOROLOGICAL STATIONS



3.2.5 BUOY METEOROLOGICAL DATA

The effects of land/sea breeze on ambient pollutant concentrations will be considered in this analysis. Therefore, it is necessary to include observations of buoy stations in the CALMET analysis. The buoy stations that are proposed for this analysis are listed in Table A-4 of Appendix A. The locations of the buoy stations with respect to the modeling domain are shown in Figure 3-6. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain along the coastline. Data from the stations will be prepared by filling missing hour records with the CALMET missing parameter value (9999). No adjustments to the data will occur.

FIGURE 3-6. PLOT OF BUOY METEOROLOGICAL STATIONS



3.3 CALMET CONTROL PARAMETERS

A few details of the CALMET model setup for sensitive parameters are discussed below.

3.3.1 VERTICAL METEOROLOGICAL PROFILE

The height of the top vertical layer will be set to 3,500 meters. This height corresponds to the top sounding pressure level for which upper air observation data will be relied upon. The vertical dimension of the domain will be divided into 12 layers with the maximum elevations for each layer shown in Table 3-1. The vertical dimensions are weighted towards the surface to resolve the mixing layer while using a somewhat coarser resolution for the layers aloft.

TABLE 3-1. VERTICAL LAYERS OF THE CALMET METEOROLOGICAL DOMAIN

Layer	Elevation (m)
1	20
2	40
3	60
4	80
5	100
6	150
7	200
8	250
9	500
10	1000
11	2000
12	3500

CALMET allows for a bias value to be applied to each of the vertical layers. The bias settings for each vertical layer determine the relative weight given to the vertically extrapolated surface and upper air wind and temperature observations. The initial guess fields are computed with an inverse distance weighting ($1/r^2$) of the surface and upper air data. The initial guess fields may be modified by a layer dependent bias factor. Values for the bias factor may range from -1 to +1. A bias of -1 eliminates upper-air observations in the $1/r^2$ interpolations used to initialize the vertical wind fields. Conversely, a bias of +1 eliminates the surface observations in the interpolations for this layer. Normally, bias is set to zero (0) for each vertical layer, such that the upper air and surface observations are given equal weight in the $1/r^2$ interpolations. The biases for each layer of the proposed modeling domain will be set to zero.

CALMET allows for vertical extrapolation of surface wind observations to layers aloft to be skipped if the surface station is close to the upper air station. Alternatively, CALMET allows data from all surface stations to be extrapolated. The CALMET parameter that controls this setting is IEXTRP. Setting IEXTRP to a value less than zero (0) means that layer 1 data from upper air soundings is ignored in any vertical extrapolations. IEXTRP will be set to -4 for this analysis (i.e., the similarity theory is used to extrapolate the surface winds into the layers aloft, which provides more information on observed local effects to the upper layers).

3.3.2 INFLUENCES OF OBSERVATIONS

Step 1 wind fields will be based on an initial guess using MM5 data and refined to reflect terrain affects. Step 2 wind fields will adjust the Step 1 wind field by incorporating the influence of local observations. An inverse distance method is used to determine the influence of observations to the Step 1 wind field. RMAX1 and RMAX2 define the radius of influence for data from surface stations to land in the surface layer and data from upper air stations to land in the layers aloft. In general, RMAX1 and RMAX2 are used to exclude observations from being inappropriately included in the development of the Step 2 wind field if the distance from an observation station to a grid point exceeds the maximum radius of influence.

If the distance from an observation station to a grid point is less than the value set for RMAX, the observation data will be used in the development of the Step 2 wind field. R1 represents the distance from a surface observation station at which the surface observation and the Step 1 wind field are weighted equally. R2 represents the comparable distance for winds aloft. R1 and R2 are used to weight the observation data with respect to the MM5 data that was used to generate the Step 1 wind field. Large values for R1 and R2 give more weight to the observations, where as small values give more weight to the MM5 data.

In this BART modeling analysis, RMAX 1 will be set to 20 km, and R1 will be set to 10 km. This will limit the influence of the surface observation data from all surface stations to 20 km from each station, and will equally weight the MM5 and observation data at 10 km. RMAX2 will be set to 50 km, and R2 will be set to 25 km. This will limit the influence of the upper air observation data from all surface stations to 50 km from each station, and will equally weight the MM5 and observation data at 25 km. These settings of radius of influence will allow for adequate weighting of the MM5 data and the observation data across the modeling domain due to the vast domain to be modeled. RAMX 3 will be set to 500 km.

4. CALPUFF

The CALPUFF model uses the output file from CALMET together with source, receptor, and chemical reaction information to predict hourly concentration impacts. A three-year CALPUFF analysis will be conducted using data and model settings as described below.

4.1 SOURCE EMISSIONS

Baseline (pre-BART) emission data will be based upon CEMS data collected by AEP over the 2002-2005 timeframe. In accordance with CENRAP guidelines, the emission rate over the highest calendar day (24-hr average) will be used to establish baseline emissions. In addition, the effectiveness of a number of different control technologies for NO_X, and SO_2 will be examined.

4.2 RECEPTOR LOCATIONS

The National Park Service (NPS) has electronic files available on their website that include the discrete locations and elevations of receptors to be evaluated in Class I area analyses. These receptor sets will be used in the CALPUFF model.

4.3 BACKGROUND OZONE AND AMMONIA

Background ozone concentrations are required in order to model the photochemical conversion of SO_2 and NO_X to sulfates (SO_4) and nitrates (NO_3). 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 will be 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 timeframe will be used. Background concentrations for ammonia will be assumed to be temporally and spatially invariant and will be set to 3 ppb, as described in the CENRAP protocol.

4.4 CALPUFF MODEL CONTROL PARAMETERS

Puff splitting is a generally accepted option in refined modeling analyses over large model domains for assessing impacts on Class I areas; however, this option would require significant computer resources and longer runtime. Based upon previous model runs performed on domains (and restricted computational grids) of the size described in this report, it is expected that runtimes could increase by a factor of 4 to 5 with the inclusion of puff-splitting. Due to this, it is felt that the use of this option will not be necessary to obtain representative concentrations at the individual Class I areas.

5. CALPOST

A three-year CALPOST analysis will be conducted to determine the visibility change in deciview (dv) caused by AEP's BART-eligible sources when compared to a natural background.

5.1 CALPOST – LIGHT EXTINCTION ALGORITHM

The CALPOST visibility processing to be used for this BART analysis is based on the October 2010 guidance from the Federal Land Managers Air Quality Related Values Workgroup (FLAG). The 2010 FLAG guidance, which was issued in draft form on July 8, 2008 and published as final guidance in December 2010, makes technical revisions to the previous guidance issued in December 2000.

Visibility impairment is quantified using the light extinction coefficient (b_{ext}), which is expressed in terms of the haze index expressed in deciviews (dv). The haze index (*HI*) is calculated as follows:

$$HI\,(\mathrm{dv}) = 10 \ln\left(\frac{b_{ext}}{10}\right)$$

The impact of a source is determined by comparing the *HI* attributable to a source relative to estimated natural background conditions. The change in the haze index, in deciviews, also referred to as "delta dv," or Δdv, based on the source and background light extinction is based on the following equation:

$$\Delta\,\mathrm{dv} \;=\; 10 * \ln\left[\frac{\mathrm{b}_{\text{ext, background}} + \mathrm{b}_{\text{ext, source}}}{\mathrm{b}_{\text{ext, background}}}\right]$$

The Interagency Monitoring of Protected Visual Environments (IMPROVE) workgroup adopted an equation for predicting light extinction as part of the 2010 FLAG guidance (often referred to as the new IMPROVE equation). The new IMPROVE equation is as follows:

$$b_{ext} = \begin{array}{l} 2.2\, f_S(RH)\left[\mathrm{NH_4(SO_4)_2}\right]_{\text{Small}} + 4.8\, f_L(RH)\left[\mathrm{NH_4(SO_4)_2}\right]_{\text{Large}} + \\ 2.4\, f_S(RH)\left[\mathrm{NH_4NO_3}\right]_{\text{Small}} + 5.1\, f_L(RH)\left[\mathrm{NH_4NO_3}\right]_{\text{Large}} + \\ 2.8\left[\mathrm{OC}\right]_{\text{Small}} + 6.1\left[\mathrm{OC}\right]_{\text{Large}} + 10\left[\mathrm{EC}\right] + 1\left[\mathrm{PMF}\right] + 0.6\left[\mathrm{PMC}\right] + \\ 1.4\, f_{SS}(RH)\left[\text{Sea Salt}\right] + b_{\text{Site-specific Rayleigh Scattering}} + 0.33\left[\mathrm{NO_2}\right] \end{array}$$

Visibility impairment predictions for the sources relied upon in this BART analysis will use the equation shown above. The use of this equation is referred to as "Method 8" in the CALPOST control file. The use of Method 8 requires that one of five different "modes" be selected. The modes specify the approach for addressing the growth of hygroscopic particles due to moisture in the atmosphere. "Mode 5" will be used in this BART analysis. Mode 5 addresses moisture in the atmosphere in a similar way as to “Method 6”, where “Method 6” is specified as the preferred approach for use with the old IMPROVE equation in the CENRAP BART modeling protocol.

CALPOST Method 8, Mode 5 requires the following:

- Annual average concentrations reflecting natural background for various particles and for sea salt
- Monthly RH factors for large and small ammonium sulfates and nitrates and for sea salts
- Rayleigh scattering parameter corrected for site-specific elevation

Tables 5-1 to Table 5-4 below show the values for the data described above that will be input to CALPOST for use with Method 8, Mode 5. The values were obtained from the 2010 FLAG guidance.

TABLE 5-1. ANNUAL AVERAGE BACKGROUND CONCENTRATION

Class I Area	$(NH_4)_2SO_4$	NH_4NO_3	OM	EC	Soil	CM	Sea Salt	Rayleigh (Mm^{-1})
Caney Creek Wilderness	0.23	0.1	1.8	0.02	0.5	3	0.03	11
Upper Buffalo Wilderness	0.23	0.1	1.8	0.02	0.5	3	0.03	11
Hercules Glades Wilderness	0.23	0.1	1.8	0.02	0.5	3	0.02	11
Wichita Mountains Wilderness	0.12	0.1	0.6	0.02	0.5	3	0.03	11

TABLE 5-2. F_L(RH) LARGE RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Caney Creek Wilderness	2.77	2.53	2.37	2.43	2.68	2.71	2.59	2.6	2.71	2.69	2.67	2.79
Upper Buffalo Wilderness	2.71	2.48	2.31	2.33	2.61	2.64	2.57	2.59	2.71	2.58	2.59	2.72
Hercules Glades Wilderness	2.7	2.48	2.3	2.3	2.57	2.59	2.56	2.6	2.69	2.54	2.57	2.72
Wichita Mountains Wilderness	2.39	2.25	2.10	2.11	2.39	2.24	2.02	2.13	2.35	2.22	2.28	2.41

TABLE 5-3. F_S(RH) SMALL RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Caney Creek Wilderness	3.85	3.44	3.14	3.24	3.66	3.71	3.49	3.51	3.73	3.72	3.68	3.88
Upper Buffalo Wilderness	3.73	3.33	3.03	3.07	3.54	3.57	3.43	3.5	3.71	3.51	3.52	3.74
Hercules Glades Wilderness	3.7	3.33	3.01	3.01	3.47	3.48	3.41	3.51	3.67	3.43	3.46	3.73
Wichita Mountains Wilderness	3.17	2.94	2.69	2.68	3.15	2.86	2.49	2.70	3.07	2.87	2.97	3.20

TABLE 5-4. F_{SS}(RH) SEA SALT RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Caney Creek Wilderness	3.9	3.52	3.31	3.41	3.83	3.88	3.69	3.68	3.82	3.76	3.77	3.93
Upper Buffalo Wilderness	3.85	3.47	3.23	3.27	3.72	3.78	3.69	3.7	3.84	3.64	3.67	3.86
Hercules Glades Wilderness	3.86	3.51	3.23	3.22	3.66	3.72	3.69	3.73	3.81	3.57	3.65	3.88
Wichita Mountains Wilderness	3.35	3.12	2.91	2.94	3.40	3.21	2.84	3.01	3.32	3.10	3.20	3.40

5.2 EVALUATING VISIBILITY RESULTS

When evaluating cost-control effectiveness of the various control scenarios, the 98th percentile of the 2001-2003 daily Δdv values output by CALPOST will be examined.

5.3 CALPOST CONTROL PARAMETERS

When a CALPOST input file is created, variable values that differ from the CENRAP protocol will generally be the result of data input/output handling issues (e.g., types of output, receptor numbers, etc.).

TABLE A-1. LIST OF SURFACE METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	KDYS	69019	-267.672	-834.095	96.9968	39.9925
2	KNPA	72222	932.565	-1020.909	97.0110	39.9908
3	KBFM	72223	857.471	-996.829	97.0101	39.9910
4	KGZH	72227	946.767	-899.515	97.0112	39.9919
5	KTCL	72228	870.843	-706.104	97.0103	39.9936
6	KNEW	53917	674.172	-1078.342	97.0080	39.9903
7	KNBG	12958	677.719	-1104.227	97.0080	39.9900
8	BVE	12884	741.996	-1153.463	97.0088	39.9896
9	KPTN	72232	550.88	-1124.295	97.0065	39.9898
10	KMEI	13865	774.911	-814.225	97.0092	39.9926
11	KPIB	72234	728.416	-915.165	97.0086	39.9917
12	KGLH	72235	557.072	-703.097	97.0066	39.9936
13	KHEZ	11111	540.777	-912.22	97.0064	39.9918
14	KMCB	11112	622.755	-949.618	97.0074	39.9914
15	KGWO	11113	640.102	-695.286	97.0076	39.9937
16	KASD	72236	692.381	-1043.261	97.0082	39.9906
17	KPOE	72239	363.294	-984.839	97.0043	39.9911
18	KBAZ	72241	-102.133	-1140.886	96.9988	39.9897
19	KGLS	72242	215.108	-1185.604	97.0025	39.9893
20	KDWH	11114	140.413	-1101.174	97.0017	39.9900
21	KIAH	12960	158.266	-1108.37	97.0019	39.9900
22	KHOU	72243	167.147	-1147.402	97.0020	39.9896
23	KEFD	12906	178.551	-1152.782	97.0021	39.9896
24	KCXO	72244	152.739	-1069.309	97.0018	39.9903
25	KCLL	11115	60.898	-1044.381	97.0007	39.9906
26	KLFK	93987	214.643	-969.355	97.0025	39.9912
27	KUTS	11116	136.056	-1026.773	97.0016	39.9907
28	KTYR	11117	150.451	-846.207	97.0018	39.9924
29	KCRS	72246	56.655	-882.642	97.0007	39.9920
30	KGGG	72247	214.572	-841.163	97.0025	39.9924
31	KGKY	11118	-9.365	-812.25	96.9999	39.9927
32	KDTN	72248	304.827	-821.713	97.0036	39.9926
33	KBAD	11119	312.743	-825.101	97.0037	39.9925
34	KMLU	11120	465.834	-816.211	97.0055	39.9926
35	KTVR	11121	561.446	-840.225	97.0066	39.9924
36	KTRL	11122	68.599	-806.417	97.0008	39.9927
37	KOCH	72249	216.81	-930.252	97.0026	39.9916
38	KBRO	12919	-44.167	-1571.387	96.9995	39.9858

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
39	KALI	72251	-103.012	-1363.74	96.9988	39.9877
40	KLRD	12920	-246.548	-1381.603	96.9971	39.9875
41	KSSF	72252	-143.386	-1183.35	96.9983	39.9893
42	KRKP	11123	-4.965	-1324.914	96.9999	39.9880
43	KCOT	11124	-219.097	-1280.964	96.9974	39.9884
44	KLBX	11125	150.245	-1207.466	97.0018	39.9891
45	KSAT	12921	-143.024	-1160.935	96.9983	39.9895
46	KHDO	12962	-211.702	-1178.172	96.9975	39.9894
47	KSKF	72253	-154.625	-1177.555	96.9982	39.9894
48	KHYI	11126	-84.156	-1122.487	96.9990	39.9899
49	KTKI	72254	38.788	-754.791	97.0005	39.9932
50	KBMQ	11127	-118.39	-1027.031	96.9986	39.9907
51	KATT	11128	-67.587	-1075.97	96.9992	39.9903
52	KSGR	11129	131.478	-1151.702	97.0016	39.9896
53	KGTU	11130	-65.624	-1033.173	96.9992	39.9907
54	KVCT	12912	6.587	-1236.788	97.0001	39.9888
55	KPSX	72255	73.878	-1253.33	97.0009	39.9887
56	KACT	13959	-22.12	-929.156	96.9997	39.9916
57	KPWG	72256	-30.147	-944.073	96.9996	39.9915
58	KILE	72257	-65.288	-988.507	96.9992	39.9911
59	KGRK	11131	-79.643	-990.173	96.9991	39.9911
60	KTPL	11132	-38.203	-981.19	96.9996	39.9911
61	KPRX	13960	143.317	-703.663	97.0017	39.9936
62	KDTO	72258	-17.018	-752.974	96.9998	39.9932
63	KAFW	11133	-29.564	-777.061	96.9997	39.9930
64	KFTW	72259	-34.302	-795.502	96.9996	39.9928
65	KMWL	11134	-99.769	-798.767	96.9988	39.9928
66	KRBD	11135	12.453	-810.467	97.0002	39.9927
67	KDRT	11136	-384.069	-1170.59	96.9955	39.9894
68	KFST	22010	-566.418	-988.838	96.9933	39.9911
69	KGDP	72261	-739.127	-873.302	96.9913	39.9921
70	KSJT	72262	-333.338	-952.54	96.9961	39.9914
71	KMRF	23034	-676.265	-1042.616	96.9920	39.9906
72	KMAF	72264	-489.668	-878.107	96.9942	39.9921
73	KINK	23023	-586.882	-890.654	96.9931	39.9920
74	KABI	72265	-252.044	-836.353	96.9970	39.9924
75	KLBB	13962	-445.006	-689.313	96.9948	39.9938
76	KATS	11137	-696.818	-763.258	96.9918	39.9931
77	KCQC	11138	-785.757	-515.724	96.9907	39.9953
78	KROW	23009	-698.822	-712.898	96.9918	39.9936
79	KSRR	72268	-789.593	-686.226	96.9907	39.9938
80	KCNM	11139	-682.79	-822.109	96.9919	39.9926
81	KALM	36870	-838.056	-752.338	96.9901	39.9932
82	KLRU	72269	-931.527	-804.112	96.9890	39.9927

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
83	KTCS	72271	-952.353	-695.469	96.9888	39.9937
84	KSVC	93063	-1042.03	-752.033	96.9877	39.9932
85	KDMN	72272	-1006.77	-799.231	96.9881	39.9928
86	KMSL	72323	854.846	-536.687	97.0101	39.9952
87	KPOF	72330	578.62	-336.733	97.0068	39.9970
88	KGTR	11140	779.065	-689.108	97.0092	39.9938
89	KTUP	93862	753.875	-600.337	97.0089	39.9946
90	KMKL	72334	727.051	-454.383	97.0086	39.9959
91	KLRF	72340	440.654	-550.661	97.0052	39.9950
92	KHKA	11141	643.365	-424.419	97.0076	39.9962
93	KHOT	72341	358.094	-604.603	97.0042	39.9945
94	KTXK	11142	278.022	-720.623	97.0033	39.9935
95	KLLQ	72342	488.655	-698.008	97.0058	39.9937
96	KMWT	72343	254.18	-599.224	97.0030	39.9946
97	KFSM	13964	237.97	-512.87	97.0028	39.9954
98	KSLG	72344	224.881	-419.064	97.0027	39.9962
99	KVBT	11143	248.074	-399.892	97.0029	39.9964
100	KHRO	11144	343.525	-405.601	97.0041	39.9963
101	KFLP	11145	404.239	-399.142	97.0048	39.9964
102	KBVX	11146	480.712	-457.853	97.0057	39.9959
103	KROG	11147	258.44	-397.685	97.0031	39.9964
104	KSPS	13966	-138.053	-664.886	96.9984	39.9940
105	KHBR	72352	-186.121	-551.123	96.9978	39.9950
106	KCSM	11148	-198.844	-513.911	96.9977	39.9954
107	KFDR	11149	-181.653	-625.205	96.9979	39.9944
108	KGOK	72353	-35.905	-458.97	96.9996	39.9959
109	KTIK	72354	-34.581	-506.938	96.9996	39.9954
110	KPWA	11150	-58.596	-493.951	96.9993	39.9955
111	KSWO	11151	-7.42	-425.828	96.9999	39.9962
112	KMKO	72355	146.972	-479.879	97.0017	39.9957
113	KRVS	72356	91.059	-438.276	97.0011	39.9960
114	KBVO	11152	87.136	-357.069	97.0010	39.9968
115	KMLC	11153	110.647	-563.566	97.0013	39.9949
116	KOUN	72357	-40.731	-527.298	96.9995	39.9952
117	KLAW	11154	-129.405	-600.222	96.9985	39.9946
118	KCDS	72360	-300.297	-610.668	96.9965	39.9945
119	KGNT	72362	-985.117	-475.563	96.9884	39.9957
120	KGUP	11155	-1059.48	-427.151	96.9875	39.9961
121	KAMA	23047	-425.319	-518.171	96.9950	39.9953
122	KBGD	72363	-395.603	-466.083	96.9953	39.9958
123	KFMN	72365	-993.449	-297.944	96.9883	39.9973
124	KSKX	72366	-770.464	-355.855	96.9909	39.9968
125	KTCC	23048	-597.271	-511.241	96.9930	39.9954
126	KLVS	23054	-732.565	-448.329	96.9914	39.9960

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
127	KEHR	72423	812.573	-199.695	97.0096	39.9982
128	KEVV	93817	822.929	-172.715	97.0097	39.9984
129	KMVN	72433	704.666	-154.54	97.0083	39.9986
130	KMDH	11156	676.745	-218.041	97.0080	39.9980
131	KBLV	11157	617.659	-136.018	97.0073	39.9988
132	KSUS	3966	547.898	-130.122	97.0065	39.9988
133	KPAH	3816	725.985	-293.319	97.0086	39.9974
134	KJEF	72445	419.01	-145.496	97.0050	39.9987
135	KAIZ	11158	387.096	-200.609	97.0046	39.9982
136	KIXD	72447	182.322	-126.913	97.0022	39.9989
137	KWLD	72450	0	-298.57	97.0000	39.9973
138	KAAO	11159	-18.976	-248.773	96.9998	39.9978
139	KIAB	11160	-23.392	-263.471	96.9997	39.9976
140	KEWK	11161	-24.645	-215.58	96.9997	39.9981
141	KGBD	72451	-161.892	-180.781	96.9981	39.9984
142	KHYS	11162	-195.191	-124.723	96.9977	39.9989
143	KCFV	11163	126.442	-319.698	97.0015	39.9971
144	KFOE	72456	114.618	-115.26	97.0014	39.9990
145	KEHA	72460	-432.761	-320.089	96.9949	39.9971
146	KALS	72462	-777.592	-245.892	96.9908	39.9978
147	KDRO	11164	-945.713	-259.163	96.9888	39.9977
148	KLHX	72463	-568.426	-195.178	96.9933	39.9982
149	KSPD	2128	-494.076	-285.176	96.9942	39.9974
150	KCOS	93037	-664.022	-102.596	96.9922	39.9991
151	KGUC	72467	-857.452	-115.301	96.9899	39.9990
152	KMTJ	93013	-940.981	-109.358	96.9889	39.9990
153	KCEZ	72476	-1020.87	-233.14	96.9880	39.9979
154	KCPS	72531	591.652	-136.14	97.0070	39.9988
155	KLWV	72534	808.939	-94.46	97.0096	39.9992
156	KPPF	74543	130.433	-293.855	97.0015	39.9973
157	KHOP	74671	841.751	-324.569	97.0099	39.9971
158	KBIX	74768	778.252	-1028.514	97.0092	39.9907
159	KPQL	11165	814.599	-1019.583	97.0096	39.9908
160	MMPG	76243	-348.007	-1248.779	96.9959	39.9887
161	MMMV	76342	-446.576	-1449.334	96.9947	39.9869
162	MMMY	76394	-316.664	-1581.176	96.9963	39.9857

TABLE A-2. LIST OF UPPER AIR METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	KABQ	23050	-869.46	-501.713	96.9897	39.9955
2	KAMA	23047	-425.319	-518.171	96.9950	39.9953
3	KBMX	53823	951.609	-702.935	97.0112	39.9936
4	KBNA	13897	920.739	-377.164	97.0109	39.9966
5	KBRO	12919	-44.167	-1571.39	96.9995	39.9858
6	KCRP	12924	-51.535	-1360.35	96.9994	39.9877
7	KDDC	13985	-259.352	-242.681	96.9969	39.9978
8	KDRT	22010	-384.069	-1170.59	96.9955	39.9894
9	KEPZ	3020	-914.558	-852.552	96.9892	39.9923
10	KFWD	3990	-28.034	-793.745	96.9997	39.9928
11	KJAN	3940	650.105	-826.452	97.0077	39.9925
12	KLCH	3937	364.461	-1089.15	97.0043	39.9902
13	KLZK	3952	432.063	-560.441	97.0051	39.9949
14	KMAF	23023	-489.668	-878.107	96.9942	39.9921
15	KOUN	3948	-40.731	-527.298	96.9995	39.9952
16	KSHV	13957	298.869	-831.166	97.0035	39.9925
17	KSIL	53813	698.079	-1054.03	97.0082	39.9905

TABLE A-3. LIST OF PRECIPITATION METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	ADDI	10063	906.825	-601.428	97.0107	39.9946
2	ALBE	10140	917.606	-821.64	97.0108	39.9926
3	BERR	10748	892.454	-683.388	97.0105	39.9938
4	HALE	13620	881.928	-601.878	97.0104	39.9946
5	HAMT	13645	863.663	-612.725	97.0102	39.9945
6	JACK	14193	898.014	-915.623	97.0106	39.9917
7	MBLE	15478	851.953	-1022.41	97.0101	39.9908
8	MUSC	15749	880.113	-567.484	97.0104	39.9949
9	PETE	16370	935.558	-908.259	97.0110	39.9918
10	THOM	18178	900.858	-915.326	97.0106	39.9917
11	TUSC	18385	895.631	-713.223	97.0106	39.9936
12	VERN	18517	825.585	-685.773	97.0098	39.9938
13	BEEB	30530	462.394	-532.485	97.0055	39.9952
14	BRIG	30900	318.015	-554.857	97.0038	39.9950
15	CALI	31140	419.619	-731.44	97.0050	39.9934
16	CAMD	31152	386.546	-699.659	97.0046	39.9937
17	DIER	32020	268.114	-643.184	97.0032	39.9942
18	EURE	32356	286.738	-390.862	97.0034	39.9965
19	GILB	32794	383.362	-435.625	97.0045	39.9961
20	GREE	32978	450.594	-483.201	97.0053	39.9956
21	STUT	36920	509.943	-596.328	97.0060	39.9946
22	TEXA	37048	278.022	-720.623	97.0033	39.9935
23	ALAM	50130	-749.044	-267.856	96.9912	39.9976
24	ARAP	50304	-441.903	-152.324	96.9948	39.9986
25	COCH	51713	-819.794	-148.582	96.9903	39.9987
26	CRES	51959	-828.107	-119.911	96.9902	39.9989
27	GRAN	53477	-451.781	-203.82	96.9947	39.9982
28	GUNN	53662	-829.573	-141.995	96.9902	39.9987
29	HUGO	54172	-539.364	-81.948	96.9936	39.9993
30	JOHN	54388	-483.95	-201.915	96.9943	39.9982
31	KIM	54538	-544.501	-283.337	96.9936	39.9974
32	MESA	55531	-993.391	-256.696	96.9883	39.9977
33	ORDW	56136	-549.552	-55.741	96.9935	39.9995
34	OURA	56203	-904.197	-168.246	96.9893	39.9985
35	PLEA	56591	-1005.94	-229.472	96.9881	39.9979
36	PUEB	56740	-633.961	-176.872	96.9925	39.9984
37	TYE	57320	-662.095	-242.254	96.9922	39.9978

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
38	SAGU	57337	-790.269	-176.061	96.9907	39.9984
39	SANL	57428	-726.777	-285.47	96.9914	39.9974
40	SHEP	57572	-714.046	-252.189	96.9916	39.9977
41	TELL	58204	-920.205	-215.382	96.9891	39.9981
42	TERC	58220	-708.229	-296.023	96.9916	39.9973
43	TRIN	58429	-642.489	-293.805	96.9924	39.9973
44	TRLK	58436	-646.185	-295.727	96.9924	39.9973
45	WALS	58781	-654.989	-262.821	96.9923	39.9976
46	WHIT	58997	-619.615	-250.12	96.9927	39.9977
47	ASHL	110281	684.787	-169.285	97.0081	39.9985
48	CAIR	111166	697.177	-301.436	97.0082	39.9973
49	CARM	111302	772.938	-177.782	97.0091	39.9984
50	CISN	111664	758.146	-151.446	97.0090	39.9986
51	FLOR	113109	751.801	-139.837	97.0089	39.9987
52	HARR	113879	762.044	-246.62	97.0090	39.9978
53	KASK	114629	650.464	-239.886	97.0077	39.9978
54	LAWR	114957	829.038	-128.708	97.0098	39.9988
55	MTCA	115888	827.797	-149.966	97.0098	39.9986
56	MURP	115983	682.261	-251.649	97.0081	39.9977
57	NEWT	116159	766.098	-72.902	97.0090	39.9993
58	REND	117187	731.633	-185.058	97.0086	39.9983
59	SMIT	118020	770.027	-283.638	97.0091	39.9974
60	SPAR	118147	658.275	-185.973	97.0078	39.9983
61	VAND	118781	685.449	-127.048	97.0081	39.9989
62	WEST	119193	778.655	-147.215	97.0092	39.9987
63	EVAN	122738	842.476	-172.871	97.0100	39.9984
64	NEWB	126151	855.854	-223.713	97.0101	39.9980
65	PRIN	127125	836.901	-153.449	97.0099	39.9986
66	STEN	128442	859.099	-156.613	97.0101	39.9986
67	JTML	128967	788.703	-239.572	97.0093	39.9978
68	ARLI	140326	-101.734	-271.373	96.9988	39.9976
69	BAZI	140620	-210.423	-201.758	96.9975	39.9982
70	BEAU	140637	59.762	-288.39	97.0007	39.9974
71	BONN	140957	211.236	-103.29	97.0025	39.9991
72	CALD	141233	-32.689	-330.586	96.9996	39.9970
73	CASS	141351	54.006	-217.645	97.0006	39.9980
74	CENT	141404	170.503	-206.038	97.0020	39.9981
75	CHAN	141427	150.257	-286.094	97.0018	39.9974
76	CLIN	141612	155.623	-157.682	97.0018	39.9986
77	COLL	141730	-265.465	-156.95	96.9969	39.9986

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
78	COLU	141740	220.541	-316.555	97.0026	39.9971
79	CONC	141867	58.918	-175.589	97.0007	39.9984
80	DODG	142164	-226.497	-277.655	96.9973	39.9975
81	ELKH	142432	-400.112	-321.784	96.9953	39.9971
82	ENGL	142560	-264.927	-324.066	96.9969	39.9971
83	ERIE	142582	162.669	-291.383	97.0019	39.9974
84	FALL	142686	83.491	-288.177	97.0010	39.9974
85	GALA	142938	-136.931	-176.83	96.9984	39.9984
86	GARD	142980	-304.059	-215.308	96.9964	39.9981
87	GREN	143248	64.308	-307.161	97.0008	39.9972
88	HAYS	143527	-190.307	-161.342	96.9978	39.9985
89	HEAL	143554	-292.133	-175.921	96.9966	39.9984
90	HILL	143686	214.018	-174.006	97.0025	39.9984
91	INDE	143954	139.335	-315.058	97.0016	39.9972
92	IOLA	143984	153.451	-269.438	97.0018	39.9976
93	JOHR	144104	134.784	-203.41	97.0016	39.9982
94	KANO	144178	-50.289	-181.177	96.9994	39.9984
95	KIOW	144341	-113.967	-329.843	96.9987	39.9970
96	MARI	145039	-4.343	-195.712	97.0000	39.9982
97	MELV	145210	137.104	-186.781	97.0016	39.9983
98	MILF	145306	39.504	-106.05	97.0005	39.9990
99	MOUD	145536	152.624	-318.136	97.0018	39.9971
100	OAKL	145888	-306.378	-96.814	96.9964	39.9991
101	OTTA	146128	158.639	-178.635	97.0019	39.9984
102	POMO	146498	143.864	-176.707	97.0017	39.9984
103	SALI	147160	-29.426	-166.908	96.9997	39.9985
104	SMOL	147551	-34.639	-171.31	96.9996	39.9985
105	STAN	147756	225.026	-164.85	97.0027	39.9985
106	SUBL	147922	-303.514	-292.808	96.9964	39.9974
107	TOPE	148167	139.116	-104.91	97.0016	39.9991
108	TRIB	148235	-387.855	-180.643	96.9954	39.9984
109	UNIO	148293	211.43	-272.537	97.0025	39.9975
110	WALL	148535	-376.076	-152.432	96.9956	39.9986
111	WICH	148830	-23.729	-288.579	96.9997	39.9974
112	WILS	148946	-111.502	-156.22	96.9987	39.9986
113	BENT	150611	781.608	-348.109	97.0092	39.9969
114	CALH	151227	865.268	-261.635	97.0102	39.9976
115	CLTN	151631	749.287	-365.634	97.0088	39.9967
116	HERN	153798	859.01	-352.458	97.0101	39.9968
117	MADI	155067	854.116	-265.064	97.0101	39.9976

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
118	PADU	156110	753.185	-293.024	97.0089	39.9974
119	PCTN	156580	834.464	-280.496	97.0099	39.9975
120	ALEX	160103	433.824	-959.253	97.0051	39.9913
121	BATN	160549	562.794	-1032.4	97.0066	39.9907
122	CALH	161411	436.113	-817.451	97.0052	39.9926
123	CLNT	161899	578.969	-999.986	97.0068	39.9910
124	JENA	164696	455.225	-912.366	97.0054	39.9918
125	LACM	165078	364.784	-1089.92	97.0043	39.9901
126	MIND	166244	346.708	-812.651	97.0041	39.9927
127	MONR	166314	463.225	-814.905	97.0055	39.9926
128	NATC	166582	369.451	-905.316	97.0044	39.9918
129	SHRE	168440	299.526	-831.143	97.0035	39.9925
130	WINN	169803	408.309	-884.596	97.0048	39.9920
131	BROK	221094	621.827	-914.236	97.0073	39.9917
132	CONE	221900	737.007	-823.513	97.0087	39.9926
133	JAKS	224472	650.361	-826.097	97.0077	39.9925
134	LEAK	224966	805.886	-943.78	97.0095	39.9915
135	MERI	225776	774.942	-814.558	97.0092	39.9926
136	SARD	227815	658.33	-593.661	97.0078	39.9946
137	SAUC	227840	763.399	-1005.93	97.0090	39.9909
138	TUPE	229003	753.571	-600.03	97.0089	39.9946
139	ADVA	230022	657.892	-298.102	97.0078	39.9973
140	ALEY	230088	505.348	-305.864	97.0060	39.9972
141	BOLI	230789	331.651	-291.689	97.0039	39.9974
142	CASV	231383	310.855	-392.187	97.0037	39.9965
143	CLER	231674	575.868	-302.209	97.0068	39.9973
144	CLTT	231711	307.465	-190.83	97.0036	39.9983
145	COLU	231791	421.287	-155.672	97.0050	39.9986
146	DREX	232331	228.23	-185.776	97.0027	39.9983
147	ELM	232568	257.758	-159.419	97.0030	39.9986
148	FULT	233079	470.408	-150.668	97.0056	39.9986
149	HOME	233999	619.93	-415.469	97.0073	39.9962
150	JEFF	234271	424.774	-172.095	97.0050	39.9984
151	JOPL	234315	238.245	-318.262	97.0028	39.9971
152	LEBA	234825	402.239	-276.263	97.0048	39.9975
153	LICK	234919	480.849	-280.775	97.0057	39.9975
154	LOCK	235027	302.048	-300.612	97.0036	39.9973
155	MALD	235207	659.982	-377.876	97.0078	39.9966
156	MARS	235298	332.062	-94.655	97.0039	39.9991
157	MAFD	235307	391.968	-300.033	97.0046	39.9973

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
158	MCES	235415	471.737	-143.942	97.0056	39.9987
159	MILL	235594	309.516	-311.398	97.0037	39.9972
160	MTGV	235834	426.937	-310.43	97.0050	39.9972
161	NVAD	235987	243.915	-272.715	97.0029	39.9975
162	OZRK	236460	349.133	-390.626	97.0041	39.9965
163	PDTD	236777	334.055	-265.018	97.0039	39.9976
164	POTO	236826	572.215	-251.455	97.0068	39.9977
165	ROLL	237263	484.503	-253.958	97.0057	39.9977
166	ROSE	237300	500.59	-175.393	97.0059	39.9984
167	SALE	237506	498.94	-274.122	97.0059	39.9975
168	SENE	237656	233.959	-383.703	97.0028	39.9965
169	SPRC	237967	238.112	-373.616	97.0028	39.9966
170	SPVL	237976	332.385	-309.374	97.0039	39.9972
171	STEE	238043	503.354	-205.135	97.0059	39.9981
172	STOK	238082	310.911	-279.239	97.0037	39.9975
173	SWSP	238223	324.053	-150.325	97.0038	39.9986
174	TRKD	238252	340.418	-395.428	97.0040	39.9964
175	TRUM	238466	326.883	-197.796	97.0039	39.9982
176	UNIT	238524	238.567	-154.494	97.0028	39.9986
177	VIBU	238609	519.633	-267.258	97.0061	39.9976
178	VIEN	238620	470.383	-193.872	97.0056	39.9983
179	WAPP	238700	606.68	-358.746	97.0072	39.9968
180	WASG	238746	556.425	-164.993	97.0066	39.9985
181	WEST	238880	489.373	-377.809	97.0058	39.9966
182	ALBU	290234	-869.46	-501.713	96.9897	39.9955
183	ARTE	290600	-689.529	-773.897	96.9919	39.9930
184	AUGU	290640	-973.07	-598.391	96.9885	39.9946
185	CARL	291469	-680.335	-811.474	96.9920	39.9927
186	CARR	291515	-819.836	-665.132	96.9903	39.9940
187	CLAY	291887	-547.124	-374.102	96.9935	39.9966
188	CLOV	291939	-566.973	-599.296	96.9933	39.9946
189	CUBA	292241	-890.304	-392.495	96.9895	39.9965
190	CUBE	292250	-951.142	-489.293	96.9888	39.9956
191	DEMI	292436	-1007.99	-799.087	96.9881	39.9928
192	DURA	292665	-767.148	-577.618	96.9909	39.9948
193	EANT	292700	-735.089	-366.94	96.9913	39.9967
194	LAVG	294862	-738.245	-461.163	96.9913	39.9958
195	PROG	297094	-811.39	-578.971	96.9904	39.9948
196	RAMO	297254	-733.737	-615.175	96.9913	39.9944
197	ROSW	297610	-698.544	-712.921	96.9918	39.9936

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
198	ROY	297638	-644.735	-422.422	96.9924	39.9962
199	SANT	298085	-807.375	-445.708	96.9905	39.9960
200	SPRI	298501	-676.681	-374.272	96.9920	39.9966
201	STAY	298518	-810.491	-495.501	96.9904	39.9955
202	TNMN	299031	-912.488	-413.425	96.9892	39.9963
203	TUCU	299156	-604.359	-508.834	96.9929	39.9954
204	WAST	299569	-638.605	-820.288	96.9925	39.9926
205	WISD	299686	-856.967	-756.366	96.9899	39.9932
206	AIRS	340179	-212.731	-597.062	96.9975	39.9946
207	ARDM	340292	-12.242	-645.633	96.9999	39.9942
208	BENG	340670	174.368	-568.011	97.0021	39.9949
209	CANE	341437	71.857	-637.935	97.0009	39.9942
210	CHRT	341544	203.233	-632.067	97.0024	39.9943
211	CHAN	341684	10.494	-475.655	97.0001	39.9957
212	CHIK	341750	-83.175	-547.26	96.9990	39.9951
213	CCTY	342334	-165	-479.536	96.9981	39.9957
214	DUNC	342654	-88.38	-610.04	96.9990	39.9945
215	ELKC	342849	-216.769	-507.879	96.9974	39.9954
216	FORT	343281	-129.964	-541.113	96.9985	39.9951
217	GEAR	343497	-118.53	-482.187	96.9986	39.9956
218	HENN	344052	-31.964	-601.206	96.9996	39.9946
219	HOBA	344202	-189.062	-547.36	96.9978	39.9951
220	KING	344865	24.538	-664.103	97.0003	39.9940
221	LKEU	344975	141.702	-520.6	97.0017	39.9953
222	LEHI	345108	71.634	-612.05	97.0009	39.9945
223	MACI	345463	-254.63	-466.154	96.9970	39.9958
224	MALL	345589	-55.127	-425.644	96.9994	39.9962
225	MAYF	345648	-258.49	-512.583	96.9970	39.9954
226	MUSK	346130	149.764	-466.905	97.0018	39.9958
227	NOWA	346485	121.551	-364.038	97.0014	39.9967
228	OKAR	346620	-88.424	-473.338	96.9990	39.9957
229	OKEM	346638	63.188	-504.958	97.0008	39.9954
230	OKLA	346661	-54.198	-510.562	96.9994	39.9954
231	PAOL	346859	-23.665	-573.142	96.9997	39.9948
232	PAWH	346935	57.704	-369.174	97.0007	39.9967
233	PAWN	346944	16.927	-398.139	97.0002	39.9964
234	PONC	347196	-8.871	-363.068	96.9999	39.9967
235	PRYO	347309	150.763	-407.824	97.0018	39.9963
236	SHAT	348101	-256.963	-407.368	96.9970	39.9963
237	STIG	348497	171.02	-523.736	97.0020	39.9953

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
238	TULS	348992	99.361	-419.873	97.0012	39.9962
239	TUSK	349023	156.629	-592.395	97.0019	39.9946
240	WMWR	349629	-156.42	-581.308	96.9982	39.9947
241	WOLF	349748	30.212	-538.388	97.0004	39.9951
242	BOLI	400876	760.886	-500.256	97.0090	39.9955
243	BROW	401150	710.048	-480.346	97.0084	39.9957
244	CETR	401587	877.35	-456.294	97.0104	39.9959
245	DICS	402489	872.14	-391.132	97.0103	39.9965
246	DYER	402680	695.792	-409.316	97.0082	39.9963
247	GRNF	403697	760.795	-395.69	97.0090	39.9964
248	JSNN	404561	765.932	-476.414	97.0090	39.9957
249	LWER	405089	885.291	-487.757	97.0105	39.9956
250	LEXI	405210	790.003	-471.897	97.0093	39.9957
251	MASO	405720	694.163	-496.166	97.0082	39.9955
252	MEMP	405954	671.8	-522.492	97.0079	39.9953
253	MWFO	405956	681.292	-516.15	97.0080	39.9953
254	MUNF	406358	678.65	-495.241	97.0080	39.9955
255	SAMB	408065	697.077	-382.536	97.0082	39.9965
256	SAVA	408108	800.788	-498.682	97.0095	39.9955
257	UNCY	409219	711.595	-384.605	97.0084	39.9965
258	ABIL	410016	-251.753	-836.027	96.9970	39.9924
259	AMAR	410211	-425.302	-517.839	96.9950	39.9953
260	AUST	410428	-67.587	-1075.97	96.9992	39.9903
261	BRWN	411136	-43.861	-1571.39	96.9995	39.9858
262	COST	411889	60.611	-1044.72	97.0007	39.9906
263	COCR	412015	-51.832	-1360.01	96.9994	39.9877
264	CROS	412131	-204.599	-868.469	96.9976	39.9922
265	DFWT	412242	-1.867	-786.341	97.0000	39.9929
266	EAST	412715	-171.024	-840.253	96.9980	39.9924
267	ELPA	412797	-886.583	-860.763	96.9895	39.9922
268	HICO	414137	-97.323	-888.181	96.9989	39.9920
269	HUST	414300	157.976	-1108.38	97.0019	39.9900
270	KRES	414880	-434.746	-611.717	96.9949	39.9945
271	LKCK	414975	99.734	-693.521	97.0012	39.9937
272	LNGV	415348	220.962	-844.674	97.0026	39.9924
273	LUFK	415424	214.652	-969.69	97.0025	39.9912
274	MATH	415661	-86.438	-1330.47	96.9990	39.9880
275	MIDR	415890	-489.385	-878.123	96.9942	39.9921
276	MTLK	416104	-672.024	-1008.98	96.9921	39.9909
277	NACO	416177	223.065	-925.966	97.0026	39.9916

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
278	NAVA	416210	28.358	-892.028	97.0003	39.9919
279	NEWB	416270	239.111	-721.818	97.0028	39.9935
280	BPAT	417174	288.962	-1110.65	97.0034	39.9900
281	RANK	417431	-472.048	-959.488	96.9944	39.9913
282	SAAG	417943	-333.338	-952.54	96.9961	39.9914
283	SAAT	417945	-143.322	-1161.27	96.9983	39.9895
284	SHEF	418252	-463.759	-1019.19	96.9945	39.9908
285	STEP	418623	-112.988	-857.918	96.9987	39.9922
286	STER	418630	-376.683	-897.195	96.9956	39.9919
287	VALE	419270	-720.749	-1015.17	96.9915	39.9908
288	VICT	419364	6.882	-1236.45	97.0001	39.9888
289	WACO	419419	-21.834	-928.823	96.9997	39.9916
290	WATR	419499	-353.767	-916.015	96.9958	39.9917
291	WHEE	419665	57.489	-1008.99	97.0007	39.9909
292	WPDM	419916	262.792	-737.786	97.0031	39.9933
293	DORA	232302	433.256	-378.797	97.0051	39.9966
294	DIXN	112353	756.057	-267.193	97.0089	39.9976
295	DAUP	12172	864.408	-1050.41	97.0102	39.9905
296	FREV	123104	847.031	-117.884	97.0100	39.9989
297	WARR	18673	890.447	-788.703	97.0105	39.9929
298	MDTN	235562	493.264	-87.222	97.0058	39.9992

TABLE A-4. LIST OF OVER WATER METEOROLOGICAL STATIONS

Number	Station ID	Input file Name	LCC East (km)	LCC North (km)	Long	Lat
1	42001	42001	746.874	-1541.35	89.67	25.9
2	42002	42002	265.486	-1650.616	94.42	25.19
3	42007	42007	795.674	-1063.667	88.77	30.09
4	42019	42019	163.178	-1342.917	95.36	27.91
5	42020	42020	30.212	-1453.738	96.7	26.94
6	42035	42035	254.465	-1193.539	94.41	29.25
7	42040	42040	859.497	-1160.066	88.21	29.18
8	BURL1	42045	743.116	-1202.117	89.43	28.9
9	DPIA1	42046	861.385	-1039.466	88.07	30.25
10	GDIL1	42047	687.984	-1164.910	89.96	29.27
11	PTAT2	42048	-4.980	-1353.398	97.05	27.83
12	SRST2	42049	288.163	-1175.682	94.05	29.67

From: hlground@aep.com
Sent: Tuesday, January 22, 2013 4:22 PM
To: Warden, Lee
Subject: Re: BART review
Attachments: NE3 Cost Estimate Summary.xlsx

Lee, nothing is ever easy.

On your first point:

In discussions with our project engineer he said that the AEP Project Management assumes the lead role regarding the collection and integration of cost information, format and documentation, management and reporting of major project cost estimates. AEP generally follows the AACE Recommended Practice of cost estimation, and the current NE3 estimate is considered a Class 4 estimate with approximately 15% project definition. At this point in the estimation process (Class 4), budgetary cost estimate information is obtained from the major OEM's (B&W, FLS), major suppliers, and the A/E firm for the balance of material estimates (ie, pipe, cable, steel, etc.). AEP obtains labor estimates from the assigned A/E and utilizes our Construction Technology group to validate labor craft rates and productivity factors. AEP determines Owner costs and uses a sophisticated monte carlo process to determine the appropriate contingency amount defined by the project risk. Firm bid pricing data is not obtained or used in the project estimate until Phase 2 at which time the detailed design is near completion.

He sent me the spreadsheet attached below.

On your second point:

We believe that your statement is still true on CDS. The technology has advanced and may be considered commercial for much smaller applications we did not consider it a viable technology for NES 3&4. Also, the costs would be higher than DFGD.

I hope that this helps.

Howard L. (Bud) Ground
Public Service Company of Oklahoma
Mgr. Governmental & Environmental Affairs
405-841-1322
405-841-1344 fax
405-488-4272 cell
hlground@aep.com

The Cowboy Code:
#10 Know where to draw the line

"Warden, Lee" <Lee.Warden@deq.ok.gov>
01/17/2013 02:21 PM
To
"hlground@aep.com" <hlground@aep.com>
cc

Subject
BART review

Bud,

I've been going through the documentation and I currently have two questions:

*? ? ? ? ?Would it be possible to obtain the documentation on the budgetary estimate used to support the purchased equipment cost? It would be good to have a confidential version and a redacted version for the record.

*? ? ? ? ?The submittal addressed both Spray dry absorber (SDA) and circulating dry scrubbing (CDS). Previously, we had dropped the circulating dry scrubbing as not being an established technology for boilers this size.
o "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."
Has this changed in the intervening years or are costs for this technology assumed to be comparable to DFGD?

Lee Warden, P.E.
Engineering Unit Supervisor
Air Quality Division
Oklahoma Department of Environmental Quality
405.702.4182

NE3 DSI-ACI-FF
Budgetary Cost Estimate Breakdown (Class 4)

WBS	Description	DSI	ACI	FF	By-Product Handling	BOP	Contingency	Total
010	Existing Conditions					$ 371,702		$ 371,702
110	Site Development					$ 7,731,298		$ 7,731,298
140	Rail Improvements	$ 3,449,477						$ 3,449,477
222	Chiller/Dehumidifier Building	$ 200,527	$ 200,526					$ 401,053
253	ACI/DSI/Byproduct Electical PDC Building	$ 174,590	$ 174,590		$ 174,590			$ 523,770
254	FF Switchgear & Control (PDC) Building			$ 2,982,830				$ 2,982,830
255	DSI/ACI Blower Building	$ 413,150	$ 413,150					$ 826,300
256	Air Compressor/ByProduct Blower Building				$ 1,066,339			$ 1,066,339
415	Booster Fan			$ 4,787,003				$ 4,787,003
416	Flue Gas Duct			$ 13,203,070				$ 13,203,070
442	ACI Unloading & Storage		$ 4,686,279					$ 4,686,279
444	ACI Feed & Injection		$ 846,019					$ 846,019
445	DSI Unloading & Storage	$ 16,080,123						$ 16,080,123
446	Dry Sorbent Injection (DSI)	$ 969,973						$ 969,973
456	Fabric Filter (FF)			$ 33,657,710				$ 33,657,710
484	Fly Ash Extraction System				$ 136,006			$ 136,006
492	Byproduct Handling System				$ 13,529,030			$ 13,529,030
605	Common Utility Racks					$ 1,214,175		$ 1,214,175
612	Plant Air					$ 1,316,703		$ 1,316,703
614	Instrument Air					$ 2,431,495		$ 2,431,495
624	Service Water					$ 831,508		$ 831,508
626	Potable Water					$ 157,324		$ 157,324
632	Process Water Drain					$ 240,327		$ 240,327
634	Storm Sewer					$ 692,336		$ 692,336
730	Medium Voltage Electric (1000V - 15 kV)			$ 1,959,632				$ 1,959,632
740	Low Voltage	$ 945,893	$ 280,845	$ 2,514,501	$ 662,324	$ 665,918		$ 5,069,480
860	Construction Indirects	$ 841,492	$ 249,847	$ 2,236,969	$ 589,221	$ 592,419		$ 4,509,948
901	Outside Professional Services	$ 112,236	$ 33,324	$ 298,361	$ 78,589	$ 79,015		$ 601,525
912	Conceptual Engineering	$ 497,466	$ 147,702	$ 1,322,433	$ 348,331	$ 350,222		$ 2,666,154
913	Detailed Design Engineering	$ 1,554,259	$ 461,474	$ 4,131,744	$ 1,088,308	$ 1,094,215		$ 8,330,000
920	Project Management & Controls	$ 1,709,125	$ 507,456	$ 4,543,430	$ 1,196,747	$ 1,203,242		$ 9,160,000
970	AEP Services	$ 2,954,457	$ 877,207	$ 7,853,942	$ 2,068,742	$ 2,079,970		$ 15,834,318
980	Contingency						$ 14,737,092	$ 14,737,092
		$ 29,902,768	$ 8,878,419	$ 79,491,624	$ 20,938,227	$ 21,051,870	$ 14,737,092	$ 175,000,000

Prepared by Joseph Zupsic 1/22/2013

Appendix III

PSO Regional Haze Agreement,

DEQ Case No. 10-025

(February 10, 2010),

as amended by the

First Amended Regional Haze Agreement,

DEQ Case No. 10-025

(March 26, 2013)

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

IN THE MATTER OF:

Public Service Company of Oklahoma,
Comanche Power Station,
Southwestern Power Station,
Northeastern Power Station,

CASE NO. 10-025

OKLAHOMA
DEPT. OF ENVIRONMENTAL QUALITY
MAR 26 2013
FILED BY: D Kay
HEARING CLERK

FIRST AMENDED REGIONAL HAZE AGREEMENT

The parties to this Agreement, the Oklahoma Department of Environmental Quality ("DEQ") and the Public Service Company of Oklahoma ("PSO") hereby agree to the entry of this First Amended Regional Haze Agreement ("Amended RHA") in order to satisfy the Best Available Retrofit Technology ("BART") requirements associated with the SO_2 and NOx requirements for PSO's Northeastern Units 3 and 4 under the Regional Haze Rule, 40 C.F.R. Subpart P, and 40 C.F.R. Part 51, Appendix Y (incorporated by reference at OAC 252:100-8-72). On February 17, 2010, DEQ and PSO entered into a Regional Haze Agreement ("Original RHA"), DEQ Case No. 10-025. Pursuant to Paragraph 42 of the Original RHA, this Amended RHA eliminates and removes Paragraphs 13 and 14 of the Original RHA. In addition, this Amended RHA replaces and supersedes Paragraphs 12 and 26 of the Original RHA as they pertain to the SO_2 and NOx requirements for the coal-fired units at PSO's Northeastern Power Station (Units 3 and 4) as follows:

12. Based on an evaluation of potentially feasible retrofit control technologies, including an assessment of the costs and visibility improvements associated therewith, the following SO_2 and NOx control technologies and emission limits as described in the Revised BART Determination for the coal-fired units at PSO's Northeastern Power Station (Units 3 and 4) (attached as Exhibit C) have been determined to be BART and shall be implemented in accordance with the schedule set forth below and in amended Paragraph 26:

Northeastern Power Station –

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)[1]	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	
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	

[1] An alternative operating scenario is provided following this table that addresses potential service disruption of coal supplies during the time period from January 31, 2014 through April 16, 2016.

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	3,136 TPY	
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	

Alternative Operating Scenario for Coal Supply Disruptions:

During the period from January 31, 2014 through April 16, 2016, if PSO experiences interruptions in the delivery of coal supplies of suitable quality to assure compliance with the 30-day rolling average SO_2 emission rate of 0.65 lb/mmBtu, due to circumstances beyond its control, PSO shall promptly notify ODEQ of the nature of the interruption, the anticipated duration of the interruption, and the steps necessary to restore normal coal deliveries to the Northeastern Units. ODEQ shall determine whether the interruption is the result of circumstances beyond the reasonable control of PSO, and notify PSO of the determination within 15 days of receipt of that notice. In the event of such an interruption, PSO shall comply with the following alternative operating scenario for the duration of the interruption and 30 days following the restoration of normal coal deliveries to the Northeastern Units. During the period the alternative operating scenario is in effect, PSO shall continue to comply with the 3,104 lb/hour SO_2 emission rate, and the 25,097 tpy SO_2 emission limitation, but PSO shall exclude the period of the interruption and the 30 days thereafter from the calculation of any 30-day rolling average or annual lb/mmBtu SO_2 emission rate. Additionally, during such a disruption, PSO shall seek to obtain replacement coal with the lowest sulfur content reasonably available.

26. Based on the above paragraphs, PSO and the DEQ agree, and it is ordered by the Executive Director as follows:

A. No later than December 31, 2013, PSO will complete installation of low NOx combustion technologies and achieve a nitrogen oxide ("NOx") emission rate of 0.23 lb/MMBtu on a 30-day rolling average at each of the two coal-fired generating units at PSO's Northeastern Power Station (Units 3 and 4).

B. Beginning on January 31, 2014, PSO will comply with a new sulfur dioxide ("SO_2") emission rate at Northeastern Units 3 and 4 of 0.65 lb/MMBtu on a 30-day rolling average, and beginning on December 31, 2014, PSO will comply with a new SO_2 emission rate of 0.60 lb/MMBtu on a 12-month rolling average at Northeastern Units 3 and 4, or comply with the alternative operating scenario set forth in Paragraph 12 during disruptions in the delivery of coal supplies. PSO will maintain those emission rates until controls are installed at one unit as provided in subparagraph 26(D), and the other unit is retired as provided in subparagraph 26(C).

C. PSO will seek all necessary regulatory approvals, and will retire one of the coal-fired generating units at Northeastern Power Station by April 16, 2016.

D. PSO will seek all necessary regulatory approvals, and install and operate a dry-sorbent injection ("DSI") system, activated carbon injection system, and a fabric filter baghouse, and secure further NOx emission reductions by April 16, 2016 on the coal-fired generating unit at Northeastern Power Station that will continue to operate. By April 16, 2016, PSO will achieve a 0.15 lb/MMBtu emission rate for NOx on a 30-day rolling average basis, and a 0.40 lb/MMBtu emission rate for SO_2 on a 30-day rolling average basis.

E. During the first year of operation of the controls required under subparagraph 26(D), PSO will develop and propose a monitoring program to test various operating profiles and other measures, to determine whether increased SO_2 removal efficiencies can be achieved during normal operations. PSO will submit the monitoring program to EPA and ODEQ for review and will implement the monitoring program during the second and third years of operation of the DSI system. PSO will evaluate and report the results of the monitoring program to EPA and ODEQ.[2]

[2] If the evaluation demonstrates that the technology is capable of sustainably achieving an emission rate of less than 0.37 lbs/MMBtu on a 30-day rolling average basis without (i) altering the unit's fuel supply, (ii) incurring additional capital costs, (iii) increasing operating expenses

F. Beginning in calendar year 2021, the Annual Capacity Factor (calculated for each calendar year as a percentage of MWH based on a rated capacity of 470 MW (net) times 8760 hours) for the operating coal-fired generating unit at Northeastern Station will be reduced as follows:

i. to no more than 70 percent in calendar years 2021 and 2022;
ii. to no more than 60 percent in calendar years 2023 and 2024; and
iii. to no more than 50 percent in calendar years 2025 and 2026.

G. No later than December 31, 2026, PSO will retire the remaining operating coal-fired generating unit at Northeastern Power Station. However, in calendar year 2021, PSO will evaluate whether the projected generation from that unit can be replaced at lower or equal total projected costs from natural gas or renewable resources. PSO will provide a copy of the evaluation to EPA and ODEQ. If power is available from such resources at a lower projected total cost (including consideration of PSO's need to recover its remaining investment in the units), then the operating unit will retire no later than December 31, 2025.

Paragraphs 12 and 26 are only amended as they pertain to the SO_2 and NOx emissions for the coal-fired units at PSO's Northeastern Power Station (Units 3 and 4). The remaining portions of these paragraphs and all other provisions of the Original RHA that are not specifically removed, replaced, or superseded by this Amended RHA shall remain in full force and effect.

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by more than a negligible amount, and/or (iv) adversely impacting overall unit operations, ODEQ will propose to revise the emission rate in the Amended RHA by 60 percent of the difference between 0.40 and the demonstrated emission rate. Upon adoption after notice and opportunity for hearing, Oklahoma, through the Secretary of Environment, will submit a Regional Haze SIP revision to EPA for approval. If the demonstrated emission rate is 0.37 lbs/MMbtu or greater, no adjustment will be made to the Amended RHA, and the emission rate from the operating Northeastern Power Station coal-fired generating unit in the Amended RHA will remain 0.40 lbs/MMBtu.

The individuals signing this Agreement certify that they are authorized to sign it and to legally bind the parties they represent. This Agreement becomes effective on the date of the later of the two signatures below.

Date: 3/20/13	Date: 3-26-13
FOR THE PUBLIC SERVICE COMPANY OF OKLAHOMA:	FOR THE OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY:
Stuart Solomon	Steven A. Thompson
STUART SOLOMON PRESIDENT and CHIEF OPERATING OFFICER	STEVEN A. THOMPSON EXECUTIVE DIRECTOR

Item 2 of Appendix 6-5

AEP-PSO Regional Haze Agreement

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

IN THE MATTER OF: **Public Service Company of Oklahoma,** **Comanche Power Station,** **Southwestern Power Station,** **Northeastern Power Station,**	**CASE NO. 10-025**

OKLAHOMA
DEPT. OF ENVIRONMENTAL QUALITY
FEB 17 2010
FILED BY:

REGIONAL HAZE AGREEMENT

The parties to this Agreement, the Oklahoma Department of Environmental Quality ("DEQ") and the Public Service Company of Oklahoma ("PSO") hereby agree to the entry of this Regional Haze Agreement ("Agreement") in order to satisfy the Best Available Retrofit Technology ("BART") requirements associated with the Regional Haze Rule, 40 C.F.R. Subpart P, and 40 C.F.R. Part 51, Appendix Y (incorporated by reference at OAC 252:100-8-72).

FINDINGS OF FACT

1. PSO is an Oklahoma corporation with its principal headquarters in Tulsa, Oklahoma.

2. PSO owns and operates the following three (3) fossil-fuel fired steam electric generating plants that are BART eligible:

> Comanche Power Station – This station is located in Comanche County, Oklahoma. The station includes two (2) 94 megawatts ("MW") combustion turbine generating units designated as Comanche Units 1 and 2. Both units were in existence prior to August 7, 1977, but not in operation prior to August 7, 1962. Each unit is a fossil-fuel fired boiler with heat inputs greater than 250-mmBtu/hr and each unit fires natural gas as its primary fuel. Because the units fire natural gas, there are no sulfur dioxide ("SO2") or particulate matter ("PM") emission control systems. Both units have the potential to emit 250 tons per year ("TPY") of NOx. The facility is currently permitted to operate under DEQ Air Quality Permit No. 2003-261-TVR, which was issued on April 27, 2006.

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

IN THE MATTER OF: **Public Service Company of Oklahoma,** **Comanche Power Station,** **Southwestern Power Station,** **Northeastern Power Station,**	**CASE NO. 10-025**

REGIONAL HAZE AGREEMENT

The parties to this Agreement, the Oklahoma Department of Environmental Quality ("DEQ") and the Public Service Company of Oklahoma ("PSO") hereby agree to the entry of this Regional Haze Agreement ("Agreement") in order to satisfy the Best Available Retrofit Technology ("BART") requirements associated with the Regional Haze Rule, 40 C.F.R. Subpart P, and 40 C.F.R. Part 51, Appendix Y (incorporated by reference at OAC 252:100-8-72).

FINDINGS OF FACT

1. PSO is an Oklahoma corporation with its principal headquarters in Tulsa, Oklahoma.

2. PSO owns and operates the following three (3) fossil-fuel fired steam electric generating plants that are BART eligible:

> Comanche Power Station – This station is located in Comanche County, Oklahoma. The station includes two (2) 94 megawatts ("MW") combustion turbine generating units designated as Comanche Units 1 and 2. Both units were in existence prior to August 7, 1977, but not in operation prior to August 7, 1962. Each unit is a fossil-fuel fired boiler with heat inputs greater than 250-mmBtu/hr and each unit fires natural gas as its primary fuel. Because the units fire natural gas, there are no sulfur dioxide ("SO2") or particulate matter ("PM") emission control systems. Both units have the potential to emit 250 tons per year ("TPY") of NOx. The facility is currently permitted to operate under DEQ Air Quality Permit No. 2003-261-TVR, which was issued on April 27, 2006.

Southwestern Power Station – This station is located in Caddo County, Oklahoma. The station includes one (1) 332 MW steam electric generating unit designated as Southwestern Unit 3. The unit is a fossil-fuel fired boiler with heat inputs greater than 250-mmBtu/hr. The unit was in existence prior to August 7, 1977, but not in operation prior to August 7, 1962. The unit fires natural gas as its primary fuel. Because the unit fires natural gas, there are no SO2 or PM emission control systems. The unit has the potential to emit 250 TPY of NOx. The facility is currently permitted to operate under DEQ Air Quality Permit No. 2003-403-TVR (M-3), which was issued on July, 20, 2008.

Northeastern Power Station – This station is located in Rogers County, Oklahoma. The station includes one (1) 495 MW gas-fired steam electric generating unit designated as Northeastern Unit 2 and two (2) 490 MW coal-fired steam electric generating units designated as Northeastern Units 3 and 4. All three (3) units are fossil-fuel fired boilers with heat inputs greater than 250-mmBtu/hr. All three (3) units were in existence prior to August 7, 1977, but not in operation prior to August 7, 1962. Northeastern Unit 2 fires natural gas as its primary fuel; consequently, it has no SO2 or PM emission control systems. Unit 2 has the potential to emit 250 TPY of NOx. Northeastern Units 3 and 4 both fire coal as their primary fuel, and both units have the potential to emit 250 TPY or more of NOx, SO2, and PM. The facility is currently permitted to operate under DEQ Air Quality Permit No. 2003-410-TVR, which was issued on February 4, 2009.

3. In 1977, the U.S. Congress enacted § 169 of the federal Clean Air Act, 42 U.S.C. § 7491, to protect the visibility of Class I Federal areas (areas determined to be of great scenic importance) from impairment. A particular type of visibility impairment is referred to as "Regional Haze." *See* 40 C.F.R. § 51.301 ("*Regional Haze* means visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources."). The federal Clean Air Act requires the development of emission limitations for pollutants contributing to Regional Haze which emanate from a variety of sources, including fossil-fuel fired electric generating power plants having a total energy generating capacity in excess of 750 MW.

4. In 1980, the U.S. Environmental Protection Agency ("EPA") promulgated regulations addressing Regional Haze reasonably attributable to specific sources or small groups of sources. *See* 40 Fed.Reg. 80,084. The regulations required States to determine which sources impair visibility and require the installation of BART on certain of those sources.

5. In 1999, EPA amended 40 C.F.R. Part 51, Subpart P, to further define the facilities subject to the Regional Haze requirements. The regulations require States to develop and implement long-term strategies for reducing air pollutants that cause or contribute to visibility impairment in Class I Federal areas.

6. On July 6, 2005, the EPA published the final "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations" (the "Regional Haze Rule"). *See* 70 Fed.Reg. 39104. The federal Clean Air Act, 42 U.S.C. §§ 7401 *et seq.*, and the Regional Haze Rule, 40 C.F.R. §§ 51.300 – 51.309, require certain States, including Oklahoma, to make reasonable progress toward the "prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas." 42 U.S.C. §§ 7491(a)(1), (b)(2) and 40 C.F.R. § 51.300. Moreover, the Regional Haze Rule requires the State of Oklahoma to develop programs to "address regional haze in each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State which may be affected by emissions from within the State." 40 C.F.R. § 51.308(d); *see also* 40 C.F.R. § 51.300(b).

7. In order to meet the requirements of the Regional Haze Rule, States must submit State Implementation Plans ("SIP") implementing the requirements of the Regional Haze Rule to EPA for approval. *See id.* The States were required to submit their SIPs prior to December 17, 2007. *See* 40 C.F.R. § 51.308(b). Each Regional Haze SIP must contain "emission limitations

representing BART and schedules for compliance with BART for each BART-eligible source that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area . . . ." *See* 40 C.F.R. § 51.308(e).

8. 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-fired boilers of more than 250 mmBtu/hr heat input). *See* OAC 252:100-8-71, 40 C.F.R. Part 51, Appendix Y(I)(C)(1), *and* 42 U.S.C. § 7491(b)(2)(A).

9. "Air pollutants emitted by sources in Oklahoma which may reasonably be anticipated to cause or contribute to visibility impairment in any mandatory Class I federal area are NOx, SO2, PM-10, and PM-2.5." OAC 252:100-8-73(b).

10. As stated in Paragraph 2 above, Comanche Units 1 and 2, Southwestern Unit 3, and Northeastern Units 2, 3, and 4, are all: fossil fuel-fired steam electric plants with heat inputs greater than 250 mmBtu/hr; units that were in existence prior to August 7, 1977, but not in operation prior to August 7, 1962; and, based on a review of existing emissions data, units that have the potential to emit more than 250 tons per year of a visibility impairing pollutant. Consequently, all six (6) units meet the definition of a BART-eligible source.

11. 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. *See* OAC 252:100-8-73(a), 42 U.S.C. § 7491(b)(2)(a), *and* 40 C.F.R. § 51.308(e). EPA 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. *See* 40 C.F.R. Part 51, Appendix Y(III)(A)(1); *see also* 70 Fed.Reg. 39,120; *and* OAC 252:100-8-73(a). Visibility impact modeling indicates that the maximum predicted visibility impacts from all six (6) of the PSO units listed in Paragraph 2 above exceed the 0.5 Δ-dv threshold at the Wichita Mountains Class I Area. *See* State of Oklahoma Regional Haze SIP, p. 72, table VI-4. Therefore, all six (6) units are subject to the BART determination requirements.

12. Since the Comanche Power Station, the Southwestern Power Station, and the Northeastern Power Station have a total generating capacity in excess of 750 MW, the Appendix Y guidelines were used to prepare BART determinations for each station. Based on an evaluation of potentially feasible retrofit control technologies, including an assessment of the costs and visibility improvements associated therewith, the following control technologies and emission limits as described in the BART Determinations for each of the three (3) stations (attached as Exhibits A, B, and C; collectively "BART Determinations") have been determined to be BART and shall be implemented within 5 years of EPA's approval of Oklahoma's Regional Haze SIP:

Comanche Power Station -

Control	**Unit 1**	**Unit 2**
NO_X Control	Dry Low-NO_X Burners	Dry Low-NO_X Burners
NOx Emission Rate (lb/mmBtu)	0.15 lb/mmBtu (30-day average)	0.15 lb/mmBtu (30-day average)

Southwestern Power Station -

Control	**Unit 3**
NO_X Control	LNB with OFA
NOx Emission Rate (lb/mmBtu)	0.45 lb/mmBtu (30-day rolling average)

Northeastern Power Station -

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 average)	716 lb/hr (30-day rolling average)	716 lb/hr (30-day rolling 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. 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.

13. In the event that: (i) EPA disapproves the DEQ determination described in the BART Determinations that Dry-Flue Gas Desulfurization with Spray Dryer Absorber ("Dry FGD with SDA") is not cost-effective for SO2 control; and (ii) all administrative and judicial appeals of EPA's disapproval have been exhausted, then the low-sulfur coal requirement in Paragraph 12 and

the BART Determinations for SO2 shall be replaced with a requirement that Northeastern Units 3 and 4 shall, at the election of the owner and operator of the Unit, either: (i) install Dry FGD with SDA or meet the corresponding SO2 emission limits listed below (and further described in the Contingent BART Determination, *see* § IV(F) of Exhibit C) by January 1, 2018; or (ii) comply with the approved alternative described in Paragraph 14 prior to December 31, 2026:

Northeastern Power Station -

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 (12-month rolling average)	2,091 TPY (12-month rolling average)

14. In lieu of installing and operating BART for SO2 control at the two (2) coal fired units (i.e., Northeastern Units 3 and 4), PSO may elect to implement the fuel switching alternative approved pursuant to 40 C.F.R. § 51.308(e)(2) and as part of the long-term strategy in fulfillment of 40 C.F.R. § 51.308(d)(3). *See* Greater Reasonable Progress Alternative Determination, § IV(G) of Exhibit C). As detailed in the Alternative Determination, implementation of this alternative requires PSO to achieve by December 31, 2026 a combined annual SO2 emission limit that is equivalent to: (i) the SO2 emission limits provided in Paragraph 13 for installing and operating Dry FGD with SDA on one (1) of these coal-fired units; and (ii) being at or below the SO2 emissions that would result from switching the other one (1) coal-fired unit to natural gas. By adopting the emission limits described in the previous sentence, DEQ and PSO expect the cumulative SO2 emissions from Northeastern Units 3 and 4 to be approximately seven percent (43 %) less than would be achieved through the installation and operation of Dry FGD with SDA at both units. *See*

Alternative Determination. If PSO has elected to comply with the emission limits provided in this Paragraph 14 and if, prior to January 1, 2022, any of these units is required by any environmental law other than the Regional Haze Rule to install flue gas desulfurization equipment or achieve an SO2 emissions rate lower than 0.10 lb/mmBtu, and if PSO proceeds to take all necessary steps to comply with such legal requirement, the enforceable emission limits adopted pursuant to this Paragraph 14 in the operating permits for the affected coal units shall be adjusted, with the reasonable consent of DEQ and PSO, as appropriate to reflect the installation of that equipment or the emission rates specified under such legal requirement.

15. PSO and DEQ agree that it is beneficial to resolve this matter promptly and by agreement.

16. PSO and DEQ waive the filing of a petition or other pleading, and PSO waives the right to a hearing.

CONCLUSIONS OF LAW

17. DEQ has regulatory jurisdiction and authority in this matter, and PSO is subject to the jurisdiction and authority of DEQ under Oklahoma law, 27A Okla. Stat. ("O.S.") §§ 2-5-101 to -118, and the rules promulgated thereunder at Oklahoma Administrative Code ("OAC"), Title 252, Chapter 100, Air Pollution Control. This Order is executed under the authority of, and in conformity with, 27A O.S. § 2-5-110(G).

18. PSO and DEQ are authorized by 75 O.S. § 309(E) and 27A O.S. § 2-3-506(B) to resolve this matter by agreement.

19. "Air pollutants emitted by sources in Oklahoma which may reasonably be anticipated to cause or contribute to visibility impairment in any mandatory Class I federal area are NOx, SO2, PM-10, and PM-2.5." OAC 252:100-8-73(b).

20. DEQ administrative rules provide that BART applicability "shall be determined using the criteria in Section III of Appendix of 40 CFR 51 in effect on July 6, 2005." OAC 252:100-8-73(a); *see also* OAC 252:100-8-72 ("Appendix Y, Guidelines for BART Determinations Under the Regional Haze Rule, of 40 CFR 51 is hereby incorporated by reference as it exists July 6, 2005."). Similarly, the corresponding Federal regulations provide, "[t]he determination of BART for fossil fuel-fired power plants having a total generating capacity greater than 750 megawatts [MW] must be made pursuant to the guidelines in appendix Y of this part (Guidelines for BART Determinations Under the Regional Haze Rule)." *See* 40 C.F.R. § 51.308(e)(1)(ii)(B); see *also* 42 U.S.C. § 7491(b)(2)(B). As described in Paragraph 2 of the Statement of Facts, each of the Comanche Power Station, Southwestern Power Station, and Northeastern Power Station, has a total generating capacity greater than 750 MW and, therefore, the BART determinations for each of these stations must be made pursuant to the "Guidelines for BART Determinations Under the Regional Haze Rule."

21. State and Federal rules define BART-eligible sources to 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-fired boilers of more than 250 mmBtu/hr heat input). *See* OAC 252:100-8-71, 40 C.F.R. Part 51, Appendix Y(I)(C)(1), *and* 42 U.S.C. § 7491(b)(2)(A). As stated in Paragraphs 2 and 10 of the Statement of Facts, Comanche Units 1 and 2, Southwestern Unit 3, and Northeastern Units 2, 3, and 4 meet all three (3) criteria listed above and, therefore, meet the definition of a BART eligible source.

22. OAC 252:100-8-73(a) provides in part:

> Each BART-eligible source that emits any air pollutant which may reasonably be anticipated to cause or contribute to visibility impairment in any mandatory Class I Federal area is subject to BART. This shall be determined using the criteria in Section III of Appendix Y of 40 CFR 51 in effect on July 6, 2005. Thresholds for visibility impairment are set forth in OAC 252:100-8-73(a)(1) and (2).
>
> (1) A source that is responsible for an impact of 1.0 deciview or more is considered to cause visibility impairment.
>
> (2) A source that causes an impact greater than 0.5 deciviews contributes to visibility impairment.

As stated in Paragraph 11 of the Statement of Facts, Comanche Units 1 and 2, Southwestern Unit 3, and Northeastern Units 2, 3, and 4, each contribute greater than 0.5 deciviews to visibility impairment at the Wichita Mountains Class I Area and, therefore, are considered subject to BART.

23. OAC 252:100-8-75(e) provides that "[t]he owner or operator of each BART-eligible source subject to BART shall install and operate BART no later than five years after EPA approves the Oklahoma Regional Haze SIP." Similarly, the Federal rule states that each Regional Haze SIP must contain "[a] requirement that each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision." 40 C.F.R. § 51.308(e)(1)(iv).

24. In lieu of installing and operating BART, the Federal rules provide that States may allow sources subject to BART to implement an alternative demonstrated to "achieve greater reasonable progress toward natural visibility conditions." *See* 40 C.F.R. § 51.308(e). Any approved Greater Reasonable Progress Alternative shall comply with the requirements of 40 C.F.R. § 51.308(e)(2).

25. In addition to the BART requirements, the Federal rules give States authority to adopt "emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals" as part of the long-term strategy that addresses regional haze visibility impairment. *See* 40 C.F.R. § 51.308(d)(3).

AGREEMENT

26. Based on the above paragraphs, PSO and the DEQ agree, and it is ordered by the Executive Director as follows:

A. PSO, at its election, shall either: (i) install and operate BART and achieve the related emission limits at the Comanche Power Station, the Southwestern Power Station, and the Northeastern Power Station as set forth in Paragraph 12 and the corresponding BART Determinations, within 5 years of EPA's approval of Oklahoma's Regional Haze SIP; or (ii) implement the approved Greater Reasonable Progress Alternative (i.e., natural gas fuel switching alternative) described in Paragraph 14 and the Alternative Determinations by December 31, 2026.

B. In the event that EPA disapproves the DEQ determination that Dry FGD with SDA is not cost-effective for SO2 control at Northeastern Units 3 and 4 and such disapproval is upheld after all judicial and/or administrative appeals have been exhausted, the SO2 related portions of the BART Determinations and the related SO2 emission limits set forth in Paragraph 12 shall not have any further force or effect, and PSO, at its election, shall either: (i) achieve the SO2 emission limits at the Northeastern Units 3 and 4 on or before January 1, 2018 as set forth in Paragraph 13 and the corresponding Contingent BART Determinations; or (ii) implement the approved Greater Reasonable Progress Alternative (i.e., natural gas fuel switching alternative) on or before December 31, 2026 as set forth in Paragraph 14 and the Alternative Determination.

27. Any control equipment required to be installed as BART shall be properly operated and maintained. *See* 40 C.F.R. § 51.308(e)(v).

28. Nothing in this Agreement shall constitute or be construed as a release for any claim or cause of action related to any NSR or New Source Performance Standard ("NSPS") liability under the Clean Air Act or the rules promulgated thereunder.

29. The emission limits required by this Agreement shall be incorporated into any otherwise required construction or operating permit issued to PSO for the affected units.

30. This Agreement shall be incorporated into the Regional Haze State Implementation Plan submitted to EPA for approval by the State of Oklahoma.

GENERAL PROVISIONS

31. PSO agrees to perform the requirements of this Agreement within the time frames specified unless performance is prevented or delayed by events which are a "force majeure." For purposes of this Agreement, a force majeure event is defined as any event arising from causes beyond the reasonable control of PSO or PSO's contractors, subcontractors or laboratories which delays or prevents the performance of any obligation under this Agreement. Examples are vandalism; fire; flood; labor disputes or strikes; weather conditions which prevent or seriously impair construction activities; civil disorder or unrest; and "acts of God." Force majeure events do *not* include increased costs of performance of the tasks agreed to in this Agreement, or changed economic circumstances. PSO must notify DEQ in writing within thirty (30) days after PSO knows or should have known of a force majeure event that is expected to cause a delay in achieving compliance with any requirement of this Agreement. Failure to submit notification within thirty (30) days waives the right to claim force majeure.

32. No informal advice, guidance, suggestions or comments by employees of DEQ regarding reports, plans, specifications, schedules, and other writings affect PSO's obligation to obtain written approval by DEQ, when required by this Agreement.

33. Unless otherwise specified, any report, notice or other communication required under this Agreement must be in writing and must be sent to:

For the Department of Environmental Quality:

Eddie Terrill, Director
Air Quality Division
P.O. Box 1677
Oklahoma City, OK 73101-1677

With copies to:

Robert D. Singletary
Environmental Attorney Supervisor
Oklahoma Department of Environmental Quality
Office of General Counsel
P.O. Box 1677
Oklahoma City, OK 73101-1677

Lee Warden, Environmental Engineering Manager
Air Quality Division
Oklahoma Department of Environmental Quality
P.O. Box 1677
Oklahoma City, OK 73101-1677

For PSO:

Howard L. (Bud) Ground
Manager State and Governmental & Environmental Affairs
Public Service Company of Oklahoma
1601 Northwest Expressway, Suite 1400
Oklahoma City, OK 73118

With copies to:

Janet Henry
Associate General Counsel
American Electric Power Service Corporation
1 Riverside Plaza
Columbus, OH 43215

34. This Agreement is enforceable as a final order of the Executive Director of DEQ. DEQ retains jurisdiction of this matter for the purposes of interpreting, implementing and enforcing the terms and conditions of this Agreement and for the purpose of resolving disputes.

35. Nothing in this Agreement limits DEQ's right to take enforcement action for violations discovered or occurring after the effective date of this Agreement.

36. Nothing in this Agreement excuses PSO from its obligation to comply with all applicable federal, state and local statutes, rules and ordinances. PSO and DEQ agree that the provisions of this Agreement are considered severable, and if a court of competent jurisdiction finds any provisions to be unenforceable because they are inconsistent with state or federal law, the remaining provisions will remain in full effect.

37. To ensure continuous and uninterrupted responsibility for the activities required by this Agreement, PSO agrees to provide a copy of the Agreement to any purchaser of an affected unit prior to sale. PSO agrees to notify any such purchaser that the obligations under this Agreement are binding on the purchaser and shall notify DEQ of the sale within ten (10) days thereof and provide DEQ with the name of the purchaser.

38. The provisions of this Agreement apply to and bind PSO and DEQ and their officers, directors, employees, agents, successors and assigns. No change in the ownership or corporate status of PSO will affect PSO's responsibilities under this Agreement.

39. This Agreement is for the purpose of settlement. Neither the fact that PSO and DEQ have agreed to this Agreement, nor the Findings of Fact and Conclusions of Law in it, shall be used for any purpose in any proceeding except the enforcement by PSO and DEQ of this Agreement and, if applicable, a future determination by DEQ of eligibility for licensing or permitting. As to others who are not parties to this Agreement, nothing contained in this Agreement is an admission by PSO of the Findings of Fact or Conclusions of Law, and this Agreement is not an admission by PSO of liability for conditions at or near the facility and is not a waiver of any right, cause of action or defense PSO otherwise has.

40. PSO and DEQ agree that the venue of any action in district court for the purposes of interpreting, implementing and enforcing this Agreement will be Oklahoma County, Oklahoma.

41. The requirements of this Agreement will be considered satisfied and this Agreement terminated when PSO receives written notice from DEQ that PSO has demonstrated that all the terms of the Agreement have been completed to the satisfaction of DEQ.

42. PSO and DEQ may amend this Agreement by mutual consent. Such amendments must be in writing and the effective date of the amendments will be the date on which they are filed by DEQ.

43. The individuals signing this Agreement certify that they are authorized to sign it and to legally bind the parties they represent.

44. This Agreement becomes effective on the date of the later of the two signatures below.

Date: 1/19/10	Date: 2-17-10
FOR THE PUBLIC SERVICE COMPANY OF OKLAHOMA:	FOR THE OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY:
Stuart Solomon	Steven A. Thompson
STUART SOLOMON PRESIDENT and CHIEF OPERATING OFFICER	STEVEN A. THOMPSON EXECUTIVE DIRECTOR

Oklahoma Department of Environmental Quality
Air Quality Division

BART Application Analysis — **January 19, 2010**

COMPANY:	**AEP- Public Service Company of Oklahoma**
FACILITY:	**Comanche Power Station**
FACILITY LOCATION:	**Comanche County, Oklahoma**
TYPE OF OPERATION:	**(2) 94 MW Gas Turbine Electric Generating**
Units	
REVIEWER:	**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).

Comanche Units 1 and 2 are fossil-fuel fired steam electric plants with heat inputs greater than 250-mmBtu/hr. The 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, a visibility impairing pollutant. Therefore, Comanche Units 1 and 2 meet the definition of a BART-eligible source.

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 Comanche Units 1 and 2 exceeded the 0.5 Δ-dv threshold at the Wichita Mountains Class I Area. Therefore, Comanche Units 1 and 2 were determined to be BART applicable sources, subject to the BART determination requirements.

III. DESCRIPTION OF BART SOURCES

Baseline emissions from Comanche Units 1 and 2 were developed based on a combination of CEM data and operating records. 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, baseline 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 maximum hourly mass emission rates for each turbine by the turbine's full heat input at that rate. In addition, the duct burners have not operated for several years, and not over the baseline period. Emissions for the duct burners are not included in the analysis.

Table 1: Comanche Power Station- Operating Parameters for BART Evaluation

Parameter	Comanche Unit 1		Comanche Unit 2	
Plant Configuration	Combustion Turbine with Integrated Heat Recovery Steam Genertor		Combustion Turbine with Integrated Heat Recovery Steam Genertor	
Gross Output (nominal)	94 MW		94 MW	
Maximum Input to Turbine	1,250 mmBtu/hr		1,250 mmBtu/hr	
Primary Fuel	Natural gas		Natural gas	
Existing NO_X Controls	None		None	
Existing PM_{10} Controls	NA		NA	
Existing SO_2 Controls	NA		NA	
Baseline Emissions Pollutant	**Baseline Actual Emissions**		**Baseline Actual Emissions**	
	lb/hr	**lb/mmBtu**	**lb/hr**	**lb/mmBtu**
NO_X	**870.0**	**0.696**	**766.3**	**0.613**
SO_2	**0.75**	--	**0.75**	--
PM_{10}	**8.25**	--	**8.25**	--

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.

Because the units fire natural gas, emissions of sulfur dioxide (SO_2) and particulate matter (PM) are minimal. There are no SO_2 or PM post-combustion control technologies with a practical application to natural gas-fired turbines. BART is good combustion practices. A full BART analysis was conducted for NO_X.

Table 2: Proposed BART Controls and Limits

Unit	NO_X BART Emission Limit	BART Technology
Comanche Unit 1	0.15 lb/mmBtu (30-day average)	Dry Low NO_X Burners (DLNB)
Comanche Unit 2	0.15 lb/mmBtu (30-day average)	Dry Low NO_X Burners (DLNB)

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 Comanche Units 1 and 2 are listed in Table 3.

Table 3: List of Potential Control Options

Control Technology
Combustion Controls
Dry Low NO_X Burners (DLNB)
Post Combustion Controls
Selective Catalytic Reduction (SCR)

In support of the Regional Haze Rule, EPA also prepared a cost-effectiveness analysis for retrofit control technologies on oil- and gas-fired units. EPA's analysis concluded that, although a number of oil- and gas-fired units could make significant cost-effective reductions in NO_X emissions using currently available combustion control technologies, for a number of units the use of combustion controls did not appear to be cost effective. As a result, EPA determined that it would be inappropriate to establish a general presumption regarding likely BART limits for oil- and natural gas fired units.

ELIMINATE TECHICALLY INFEASIBLE OPTIONS (NO_X)

Combustion Controls:

Dry Low NO_X burners (DLNB)

Low NO_X burners (DLNB) limit NO_X formation through the restriction of oxygen, lowering of flame temperature, and/or reduced residence time. LNB is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NO_X formation is limited by either one of two methods. Under staged fuel-rich conditions, low oxygen levels limit flame temperature resulting in less NO_X formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel-lean conditions, excess air will reduce flame temperatures to reduce NO_X formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NOX formation.

When utilized in new turbine designs, reductions of up to 60 percent may result. A similar level of effectiveness is expected with retrofit installations. This technology is considered a technically feasible option.

Post Combustion Controls:

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) involves injecting ammonia into turbine flue gas in the presence of a catalyst to reduce NO_X to N2 and water. Anhydrous ammonia injection systems may be used, or ammonia may be generated on-site from a urea feedstock. The units at the Comanche Station employ combustion turbines with integrated Heat Recovery Steam Generators (HRSG) that are very unique in their designs. AEP-PSO contends that it is technically infeasible to retrofit post combustion SCR NO_X control without rebuilding the generating units. Therefore SCR is not evaluated further.

EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES (NO_X)

Table 4: Technically Feasible NO_X Control Technologies- Comanche Station

Control Technology	Comanche Unit 1 Approximate NO_X Emission Rate (lb/mmBtu)	Comanche Unit 2 Approximate NO_X Emission Rate (lb/mmBtu)
DLNB	0.15	0.15
Baseline	0.696	0.613

EVALUATE IMPACTS AND DOCUMENT RESULTS (NO_X)

AEP evaluated the economic, environmental, and energy impacts associated with the proposed control option. In general, the cost estimating methodology followed guidance provided in the EPA Air Pollution Cost Control Manual. Capital costs associated with implementing the evaluated control system was provided to AEP-PSO by an after-market vendor. As LNB are not expected to incur any additional significant direct operating costs, total direct operating costs were assumed to be \$0. Indirect operating costs are consistent with control manual guidance.

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 53%.

Table 5: Economic Cost for Units 1 and 2

Cost	Control Option: DLNB
Control Equipment Capital Cost ($)	$34,660,000
Capital Recover Factor ($/Yr)	$3,530,198
Annual O&M Costs ($/Yr)	$1,386,400
Annual Cost of Control ($)	$4,916,598

Table 6: Environmental Costs for Units 1 and 2

	Unit	Baseline	DLNB
NO_X Emission Rate (lb/mmBtu)	Unit 1	0.48	0.15
	Unit 2	0.46	0.15
Annual NO_X Emission (TPY)[1]	Unit 1	1,393	435
	Unit 2	1,385	452
Annual NO_X Reduction (TPY)	Unit 1	--	958
	Unit 2	--	933
Annual Cost of Control	Units 1 & 2		$4,916,598
Cost per Ton of Reduction	--		$2,600

(1) Emissions for the BART analysis are based on maximum heat inputs of 1,250 mmBtu/hr. Annual emissions were calculated assuming a 53% capacity factor for unit 1 and a 55% capacity factor for unit 2.

B. 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 Comanche Power Station 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 Comanche Power Station 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 Comanche Generating Station, as shown in Figure 1 below.

Only those Class I areas most likely to be impacted by the Comanche Generating Station 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.

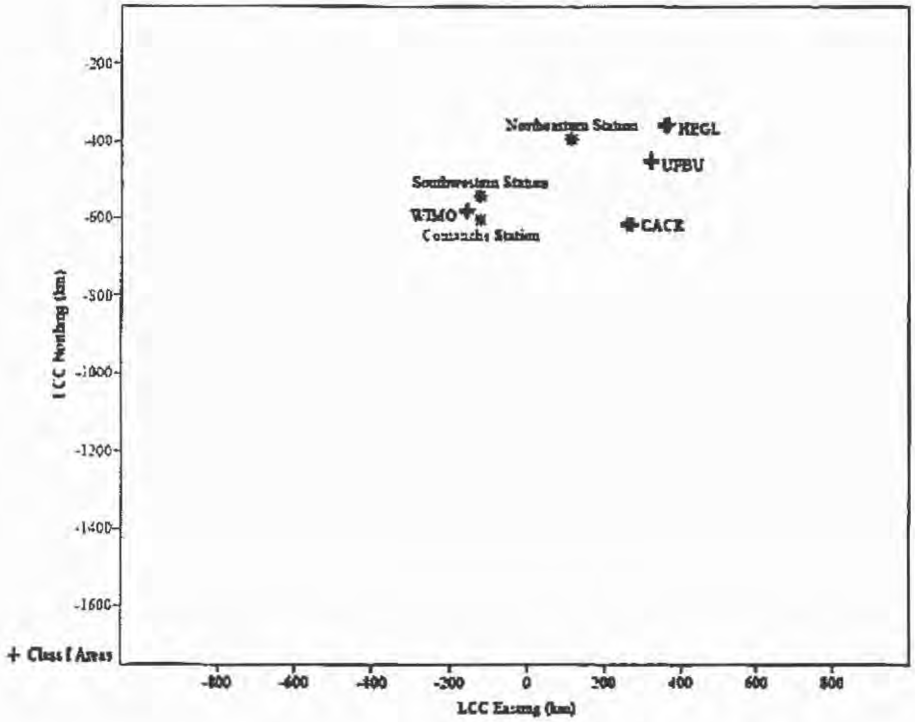

Figure 1: Plot of Facility location in relation to nearest Class I areas

REFINED MODELING:

Because of the results of the applicants screening modeling for the Comanche Generating Station, 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, August 2008)*

CALPUFF System

Predicted visibility impacts from the Comanche Generating Station 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 most modeled areas are located more than 50 km from the sources in question and the Wichita Mountains are just under the threshold at 40 km, 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 7: Key Programs **in** CALPUFF System

Program	Version	Level
CALMET	5.53a	040716
CALPUFF	5.8	070623
CALPOST	5.51	030709

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 8: 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 (surface layer, km)	20 km

Variable	Description	Value
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.

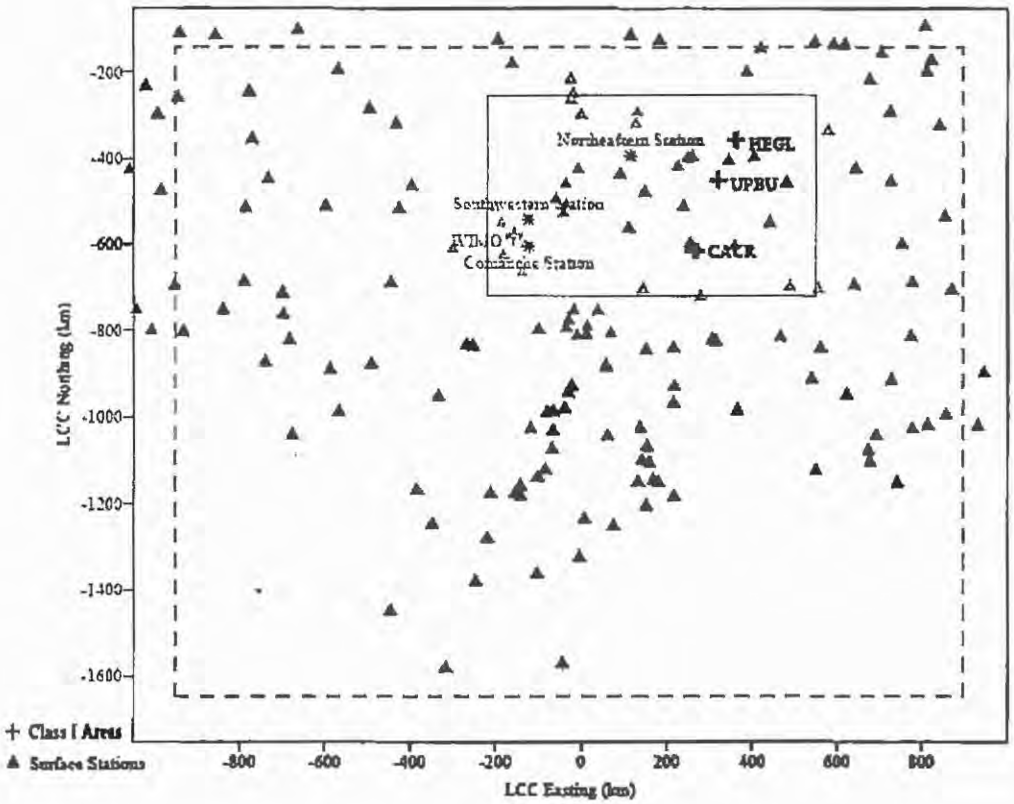

Figure 2: Plot of surface station locations

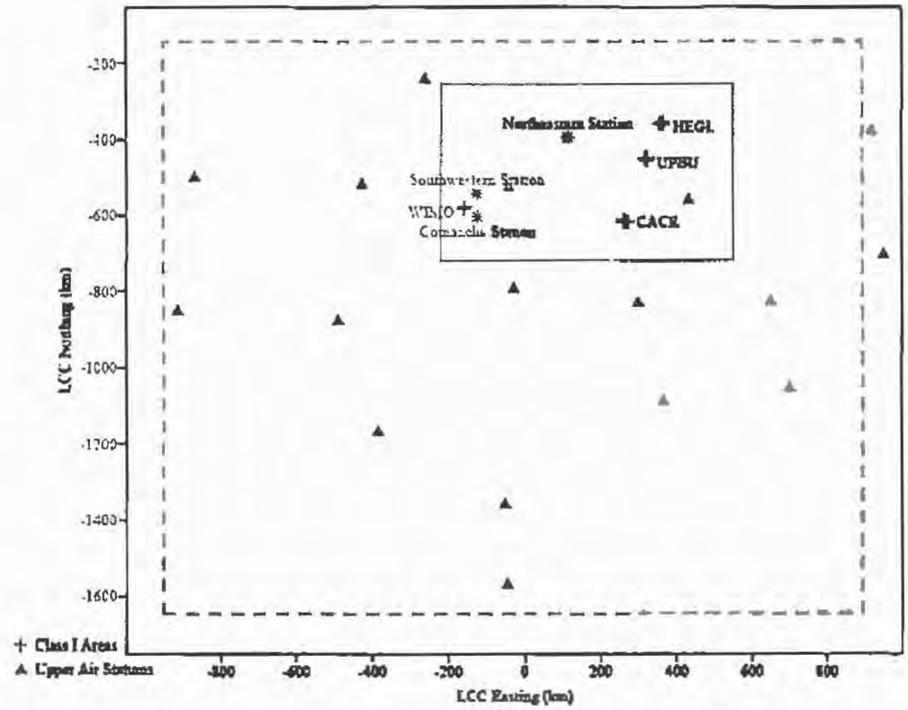

Figure 3: Plot of upper air station locations

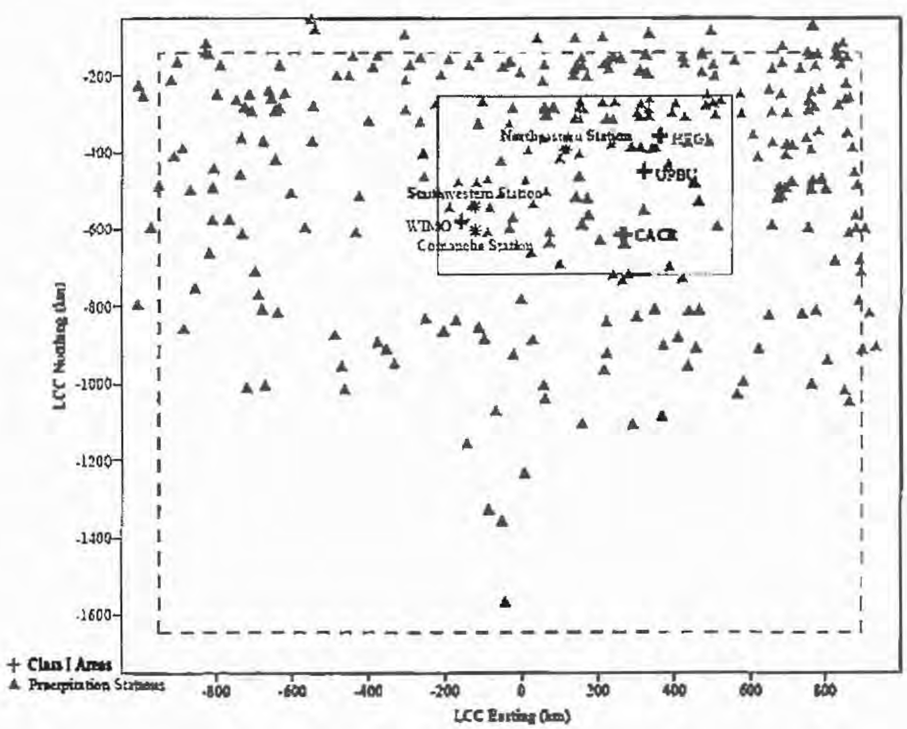

Figure 4. Plot of precipitation observation stations

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. Emissions of NO_X for the baseline runs were established based on CEM data and the highest 24-hour emissions averages for years 2001 to 2005. All particulate emissions (PM) were based on emission rates of 0.0066 lb/mmBtu with 25% filterable (coarse PM) and 75% condensable treated as (fine PM) within CALPUFF and CALPOST.

Baseline source release parameters and emissions are shown in the table below, followed by tables with data for the various control options.

Table 9: Baseline Source Parameters

Parameter	Baseline	
	Unit 1	Unit 2
Heat Input (mmBtu/hr)	1,250	1,250
Base Elevation (m)	338	338
Stack Height (m)	16	16
Stack Diameter (m)	3.11	3.11
Stack Temperature (K)	453	455
Exit Velocity (m/s)	44.82	44.82
SO2 Emissions (TPY)	0.75	0.75
NOX Emissions[1] (lb/mmBtu)	0.696	0.613
NOX Emissions TPY	870	766.3
PM_{10} Emissions Coarse (TPY)	2.06	2.06
PM_{10} Emissions Fine (TPY)	6.19	6.19

[1]Baseline NOx emissions were based on the maximum 24-hr average emission rate (lb/hr) reported by each unit during the baseline period 2003-2005. 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 heat input to the turbine at that rate.

[2]PM emissions are based on AP-42 emission factors for stationary gas turbines with filterable/condensable speciation based on NPS guidance.

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 11: 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 12: CALPUFF Visibility Modeling Results for Comanche Units 1 and 2

	2001	2002	2003	3-Year Average
Class I Area	98th Percentile Value (Δdv)	98th Percentile Value (Δdv)	98th Percentile Value (Δdv)	98th Percentile Value (Δdv)
Baseline				
Wichita Mountains	1.83	1.619	1.66	1.703
Caney Creek	0.103	0.097	0.08	0.093
Upper Buffalo	0.092	0.066	0.062	0.073
Hercules Glade	0.076	0.068	0.044	0.063
Scenario- Combustion Control- DLNB				
Wichita Mountains	0.47	0.395	0.406	0.424
Caney Creek	0.024	0.022	0.018	0.021
Upper Buffalo	0.021	0.015	0.014	0.017
Hercules Glade	0.017	0.015	0.010	0.014

C. 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 two units at the Comanche Generating Station.

New DLNB is determined to be BART for NO_X control for Units 1 and 2 based, in part, on the following conclusions:

1. Installation of new DLNB was cost effective, with a capital cost of $34,660,000 for units 1 and 2 and an average cost effectiveness of $2,600 per ton of NO_X removed for each unit over a twenty year operational life.

2. Combustion control using the LNB 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 Unit 1 and 2 are justified.

4. Annual NO_X emission reductions from new LNB on Units 1, and 2 are a total of 1,891 tons.

The Division considers the installation and operation of the BART determined NO_X controls, new DLNB, to meet the statutory requirements of BART.

V. CONSTRUCTION PERMIT

Prevention of Significant Deterioration (PSD)
Comanche Power Station 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 Comanche Station.

With installation of the BART controls, the duct burners will no longer be authorized to operate.

VI. OPERATING PERMIT

The Comanche Generating Station 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 turbines in EUG 1 and 2 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
1G1	1G1	Westinghouse /W-501B	1250	1971
1G2	1G2	Westinghouse /W-501B	1250	1971

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 turbines. 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 Dry Low-NO_X Burners, as determined in the submitted BART analysis, to reduce emissions of NO_X to below the emission limits below:
e. The permittee shall maintain the combustion controls (Low-NO_X burners) 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 Emission Limit	Averaging Period
1G1	1G1	0.15 lb/MMBTU	30-day rolling
1G2	1G2	0.15 lb/MMBTU	30-day rolling

g. Within 60 days of achieving maximum power output from each turbine, after modification of the turbines, not to exceed 180 days from initial start-up, the permittee shall conduct performance testing 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)]

1. 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.
2. The permittee shall also provide notice of the actual test date to AQD.

Oklahoma Department of Environmental Quality
Air Quality Division

BART Application **Analysis** | January **19, 2010**

COMPANY:	**AEP- Public Service Company of Oklahoma**
FACILITY:	**Southwestern Power Station**
FACILITY LOCATION:	**Caddo County, Oklahoma**
TYPE OF OPERATION:	**(1) 332 MW Steam Electric Generating Unit**
REVIEWER:	**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).

Southwestern Unit 3 is a fossil-fuel fired boiler with heat inputs greater than 250-mmBtu/hr. The unit was 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 unit has the potential to emit more than 250 tons per year of NO_X, a visibility impairing pollutant. Therefore, Southwestern Unit 3 meets the definition of a BART-eligible source.

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 Southwestern Unit 3 exceeded the 0.5 Δ-dv threshold at the Wichita Mountains Class I Area. Therefore, Southwestern Unit 3 was determined to be BART applicable sources, subject to the BART determination requirements.

III. DESCRIPTION OF BART SOURCES

Baseline emissions from Southwestern Unit 3 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, baseline 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 maximum hourly mass emission rates for the boiler by the boiler's heat input at that emission rate.

Table 1: Southwestern Power Station- Plant Operating Parameters for BART Evaluation

Parameter	Southwestern Unit 3	
Plant Configuration	Natural Gas-Fired Boiler	
Gross Output (nominal)	332 MW	
Maximum Input to Boiler	3,290 mmBtu/hr	
Primary Fuel	Natural gas	
Existing NO_X Controls	None	
Existing PM_{10} Controls	NA	
Existing SO_2 Controls	NA	
Baseline Emissions Pollutant	**Baseline Actual Emissions**	
	lb/hr	**lb/mmBtu**
NO_X	**3,705**	**1.126**
PM_{10}	**24.5**	**0.007**
SO_2	**1.97**	**0.0006**

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.

Because the unit fires natural gas, emissions of sulfur dioxide (SO_2) and particulate matter (PM) are minimal. There are no SO_2 or PM post-combustion control technologies with a practical application to natural gas-fired boilers. BART is good combustion practices. A full BART analysis was conducted for NO_X.

Table 2: Proposed BART Controls and Limits

Unit	NO_X BART Emission Limit	BART Technology
Southwestern Unit 3	0.45 lb/mmBtu (30-day average)	LNB/OFA

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 Southwestern Unit 3 are listed in Table 3.

Table 3: List of Potential Control Options

Control Technology
Combustion Controls
Burners Out of Service (BOOS)
Low NO_X Burners and Overfire Air (LNB/OFA)
Induced Flue Gas Recirculation (FGR)
Post Combustion Controls
Selective Catalytic Reduction (SCR)

In support of the Regional Haze Rule, EPA also prepared a cost-effectiveness analysis for retrofit control technologies on oil- and gas-fired units. EPA's analysis concluded that, although a number of oil- and gas-fired units could make significant cost-effective reductions in NO_X emissions using currently available combustion control technologies, for a number of units the use of combustion controls did not appear to be cost effective. As a result, EPA determined that it would be inappropriate to establish a general presumption regarding likely BART limits for oil- and natural gas fired units.

ELIMINATE TECHICALLY INFEASIBLE OPTIONS (NO_X)

Combustion Controls:

Burners Out of Service (BOOS)

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 places a load limit on the unit. AEP-PSO estimates that NO_X emissions can be reduced 20-25%. Implementation of this option will reduce the maximum firing rate of the unit, thereby creating an artificial load limit. Although this does not preclude this option from being physically implemented, the resulting load limits would effectively result in the shutdown of the units. As a result, this option is considered technically infeasible.

Induced Flue Gas Recirculation (IFGR)

FGR uses flue gas as an inert material to reduce flame temperatures. In a typical flue gas recirculation system, flue gas is collected from the heater or stack and returned to the burner via a duct and blower. The addition of flue gas reduces the oxygen content of the "combustion air" (air + flue gas) in the burner. The lower oxygen level in the combustion zone reduces flame temperatures; which in turn reduces thermal NO_X formation. When operated without additional controls, the average NO_X control efficiency range for FGR is 30 percent to 40 percent. This control option would also place load limits on the boiler and also call for plant component upgrades. As with the Burners Out Of Service, IFGR is considered technically infeasible as a standalone NO_X control for Southwestern Power Station Unit 3.

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 natural gas-fired boilers. Boilers of the size and age of the Southwestern Unit would be expected to achieve an average emission reduction in the range of 30% to 60% from baseline depending on the baseline emission rate and boiler operating conditions. Southwestern Unit 3 does not operate as base load units. The unit has historically operated as a "peaking unit" responding to increased demand for electricity. While technically feasible, LNB/OFA may not be as effective under all boiler operating conditions, especially during load changes and at low and high operating loads.

Post Combustion Controls:

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 gas-fired boilers. Based on emissions data available from the EPA Electronic Reporting website, large gas-fired boilers (with heat inputs above approximately 1,000 mmBtu/hr) have achieved actual long-term average NO_X emission rates in the range of approximately 0.02 to 0.05 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 gas-fired units, and taking into consideration long-term operation of an SCR control system (including catalyst plugging and deactivation) and the fact that the Southwestern boiler typically operates as a peaking unit, it is anticipated that SCR could achieve a controlled NO_X emission rate of 0.05 lb/mmBtu (30-day rolling average) on Southwestern Unit 3.

EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES (NO_X)

Table 4: Technically Feasible NO_X Control Technologies- Southwestern Station

	Southwestern Unit 3
Control Technology	Approximate NO_X Emission Rate (lb/mmBtu)
LNB/OFA + SCR	0.05
LNB/OFA	0.45
Baseline[1]	1.126

[1]Baseline emissions for modeling are based on the maximum 24-hour emission rate over the baseline period. Baseline emissions for cost effectiveness calculations were based on the annual average emission rate of 0.57 lb/mmBtu.

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. Major equipment costs were developed based on costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit Southwestern Unit 3 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. 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 26%.

Table 5: Economic Cost

Cost	Option 1: LNB/OFA	Option 2: LNB/OFA +SCR
Control Equipment Capital Cost ($)	$3,000,000	$68,968,400
Capital Recover Factor ($/Yr)	$305,557	$7,024,584
Annual O&M Costs ($/Yr)	$120,000	$3,682,650
Annual Cost of Control ($)	$425,557	$10,707,234

Table 6: Environmental Costs per Boiler

	Baseline	LNB/OFA	LNB/OFA +SCR
NO_X Emission Rate (lb/mmBtu)	0.57	0.45	0.05
Annual NO_X Emission (TPY)	2,136	1,686	187
Annual NO_X Reduction (TPY)	--	450	1,949
Annual Cost of Control	--	$425,557	$10,707,234
Cost per Ton of Reduction	--	$946	$5,494
Incremental Cost per ton of Reduction	--	--	$6,859

B. 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 Southwestern Power Station 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 Southwestern Power Station 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 Southwestern Power Station, as shown in Figure 1 below.

Only those Class I areas most likely to be impacted by the Southwestern Power Station 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.

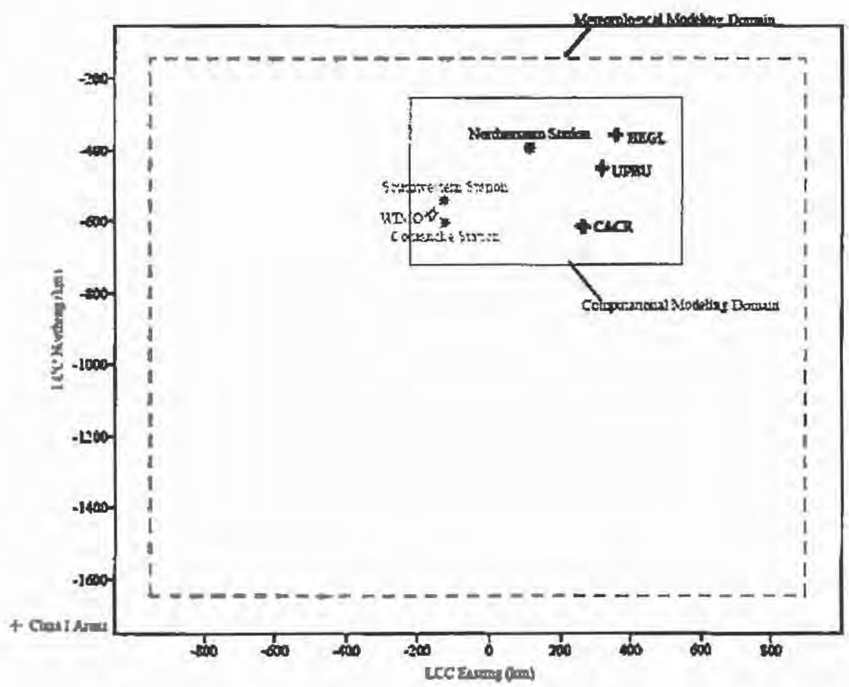

Figure 1: Plot of Facility location in relation to nearest Class I areas

REFINED MODELING:

Because of the results of the applicants screening modeling for the Southwestern Power Station, 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, August 2008)*

CALPUFF System

Predicted visibility impacts from the Southwestern Power Station 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 most modeled areas are located more than 50 km from the sources in question and the Wichita Mountains are within 44 km, 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 7: Key Programs in CALPUFF System

Program	Version	Level
CALMET	5.53a	040716
CALPUFF	5.8	070623
CALPOST	5.51	030709

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 8: 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 (surface layer, km)	20 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.

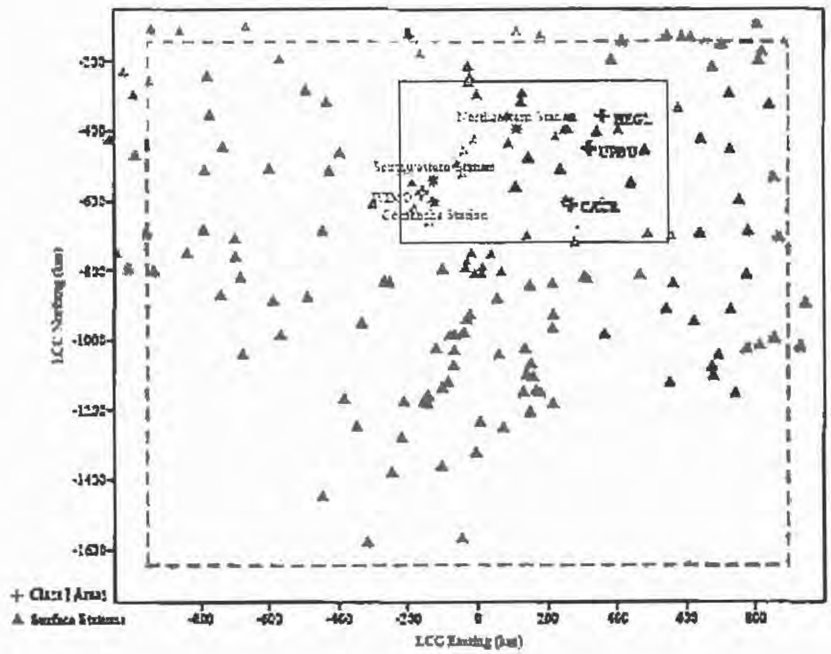

Figure 2: Plot of surface station locations

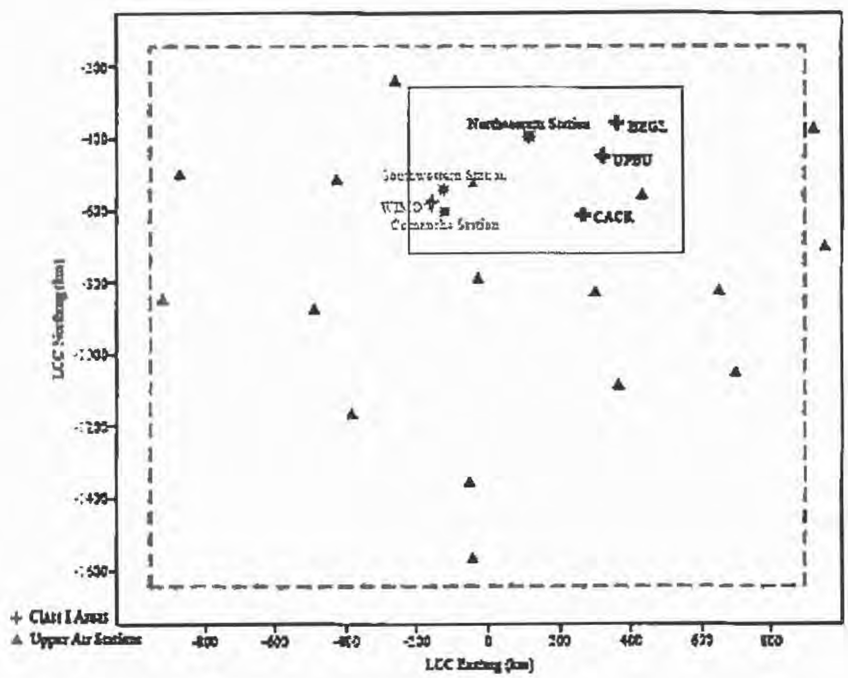

Figure 3: Plot of upper air station locations

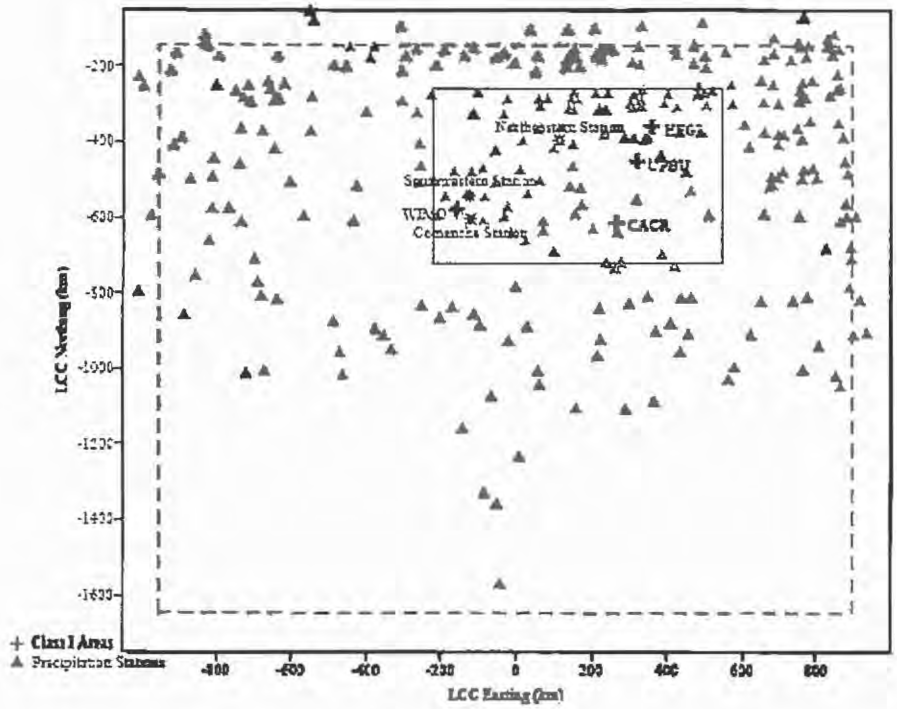

Figure 4. Plot of precipitation observation stations

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. Emissions of NO_X for the baseline runs were established based on CEM data and maximum 24-hour emissions averages for years 2001 to 2005.

Baseline source release parameters and emissions are shown in the table below, followed by tables with data for the various control options.

Table 9: Baseline Source Parameters

Parameter	Southwestern Unit 3 Natural Gas-Fired
Heat Input (mmBtu/hr)	3,290
Base Elevation (m)	371
Stack Height (m)	43
Stack Diameter (m)	4.27
Stack Temperature (K)	408
Exit Velocity (m/s)	16.26
SO2 Emissions (lb/mmBtu)	0.0006
SO2 Emissions (TPY)	8.63
NOX Emissions[1] (lb/mmBtu)	1.26
NOX Emissions TPY	16227.9
PM_{10} Fine Emissions[2] (lb/mmBtu)	0.00175
PM_{10} Fine Emissions (TPY)	6.13
PM_{10} Coarse Emissions (lb/mmBtu)	0.00525
PM_{10} Coarse Emissions (TPY)	18.39

[1]Baseline NOx emissions were based on the maximum 24-hr average emission rate (lb/hr) reported by the unit during the baseline period 2003-2005. 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]PM emissions are based on AP-42 emission factors for natural gas combustion and NPS speciation factors for (filterable and condensable).

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 11: 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 12: CALPUFF Visibility Modeling Results for Southwestern Unit 3

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	3.86	2.85	3.74	3.48
Scenario 2- Combustion Control- LNB/OFA				
Wichita Mountains	1.73	1.24	1.70	1.56

Modeling for SCR controls resulted in an approximately 88% reduction in visibility impairment from scenario two.

C. 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 unit at the Southwestern Power Station.

New LNB with OFA is determined to be BART for NOX control for Unit 3 based, in part, on the following conclusions:

1. Installation of new LNB with OFA was cost effective, with a capital cost of $3,000,000 and an average cost effectiveness of $947 per ton of NO_X removed over a twenty year operational life.

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 NO_X control levels on 30-day rolling averages of 0.45 lb/mmBtu for Unit 3 are justified.

4. Annual actual NO_X emission reductions from new LNB with OFA on Unit 3 are 450 tons.

LNB with OFA and SCR was not determined to be BART for NO_X control for Unit 3 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 Unit 3 are $65,968,400. Based on projected actual emissions, SCR could reduce overall NO_X emissions from Southwestern Unit 3 by approximately 1,441 tpy (compared to combustion controls); however, the incremental cost associated with this reduction is approximately $10,281,677 per year, or $6,859/ton.

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. SCR control may not be as effective on boilers that operate as peaking units, as NO_X reduction in an SCR is a function of flue gas temperature.

The Division considers the installation and operation of the BART determined NO_X controls, new LNB with OFA, to meet the statutory requirements of BART.

V. CONSTRUCTION PERMIT

Prevention of Significant Deterioration (PSD)

Southwestern Power Station 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 Southwestern Station.

VI. OPERATING PERMIT

The Southwestern Power Station 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. Unit 3 in EUG 1 is 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
3	3	Babcock/Wilcox, **RB-426**	3,290	May 1967

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 NOX to below the emission limits below:
   i. Low-NOX Burners,
   ii. Overfire Air, and

e. The permittee shall maintain the combustion controls (Low-NOX burners, overfire air) 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#	NOX Emission Limit	Averaging Period
3	03	**0.45 lb/MMBTU**	30-day rolling

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

h. After installation of the BART, the affected facilities shall only be fired with natural gas.

i. Within 60 days of achieving maximum power output from the boiler, after modification of the boiler, 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 NOX, 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.

iii. The following USEPA methods shall be used for testing of emissions, unless otherwise approved by Air Quality:

Method 1:	Sample and Velocity Traverses for Stationary Sources.
Method 2:	Determination of Stack Gas Velocity and Volumetric Flow Rate.
Method 3:	Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.

EXHIBIT C

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

Control Technology	Northeastern Unit 3 Approximate SO_2 Emission Rate (lb/mmBtu)	Northeastern Unit 4 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.

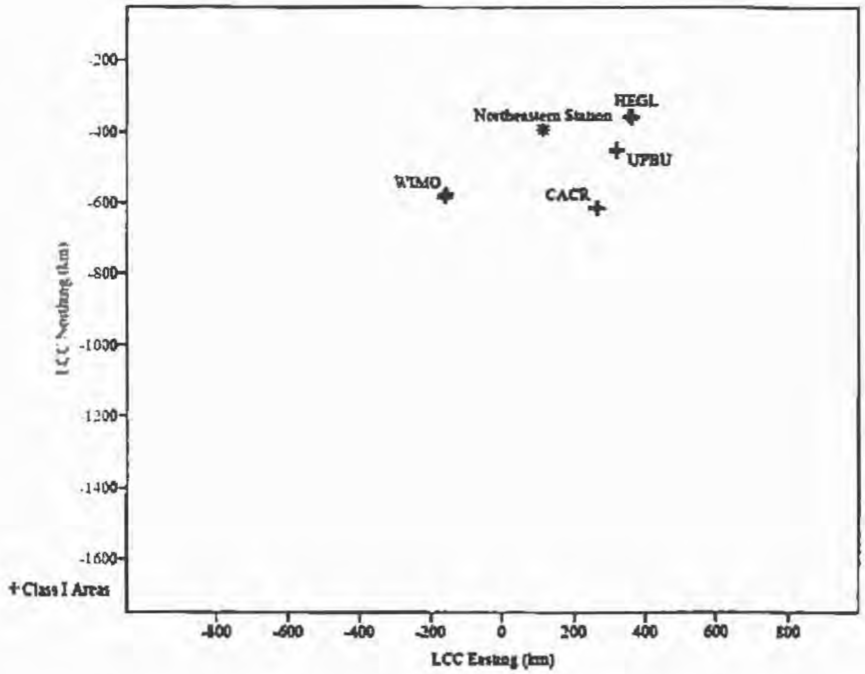

Figure 1: Plot of Facility location in relation to nearest Class I areas

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.

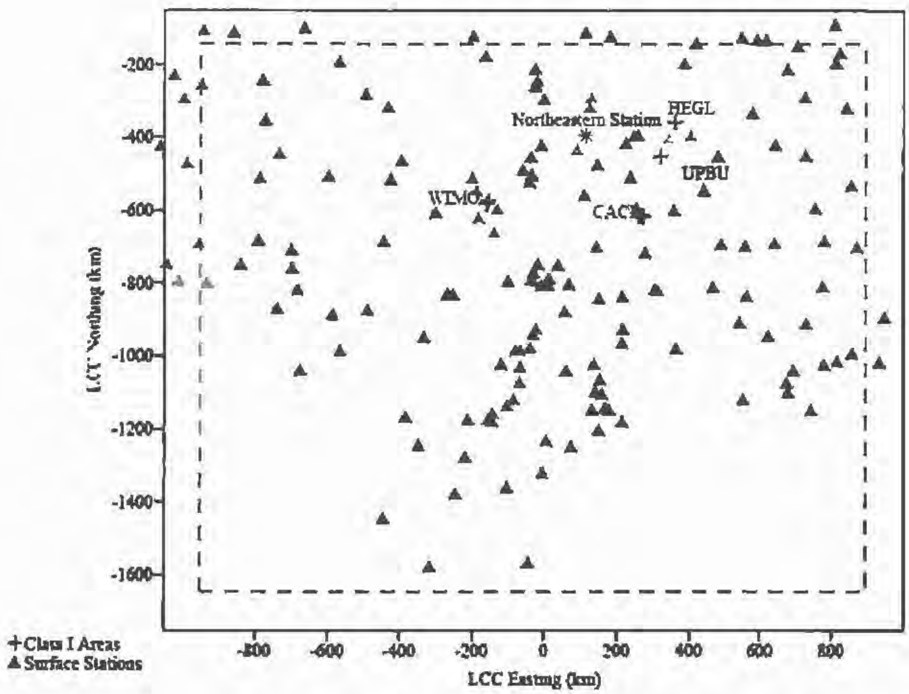

Figure 2: Plot of surface station locations

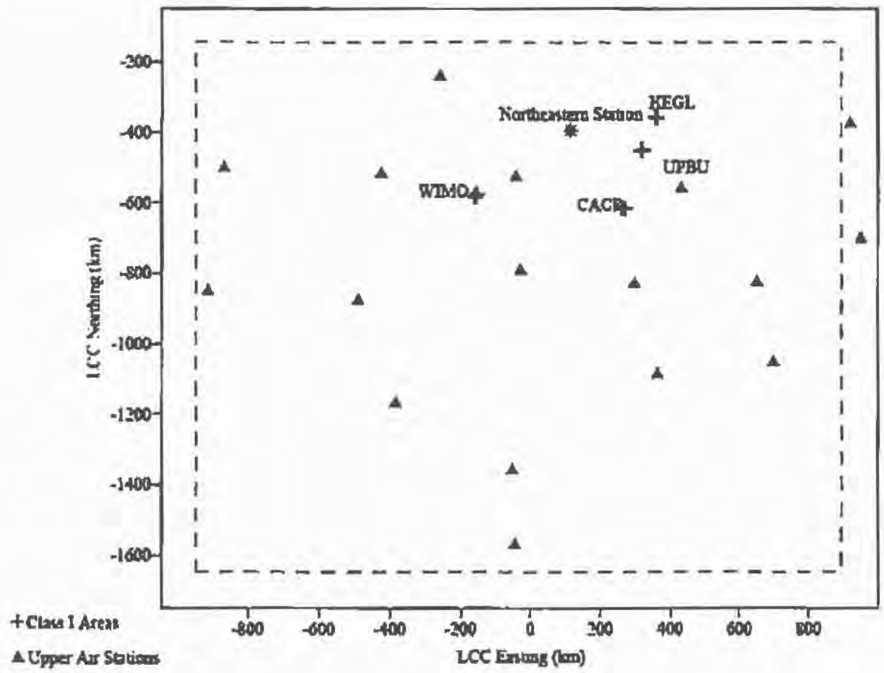

Figure 3: Plot of upper air station locations

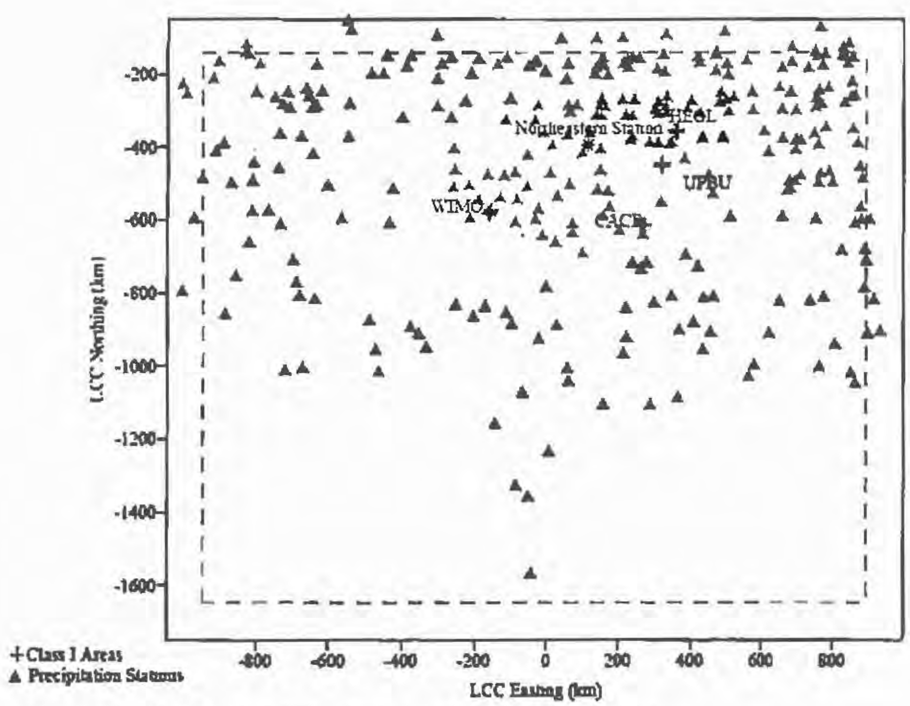

Figure 4. Plot of precipitation observation stations

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

Parameter	Baseline[1]		
	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 98th Percentile Value (Δdv)	2002 98th Percentile Value (Δdv)	2003 98th Percentile Value (Δdv)	3-Year Average 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 98th Percentile Value (Δdv)	2002 98th Percentile Value (Δdv)	2003 98th Percentile Value (Δdv)	3-Year Average 98th Percentile Value (Δdv)
Baseline				
Wichita Mountains	1.123	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 98th 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 98th Percentile Value (Δdv)	2002 98th Percentile Value (Δdv)	2003 98th Percentile Value (Δdv)	3-Year Average 98th 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.

Appendix IV

Notice of Public Hearing and Opportunity to Comment

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

Notice of Public Hearing and Opportunity for Comment
Revision to Regional Haze State Implementation Plan
Including Revisions to Affected Portions of the
Interstate Transport SIP for the 1997 8-hour Ozone and 1997 $PM_{2.5}$ NAAQS

The Oklahoma Department of Environmental Quality (DEQ) hereby announces a public hearing and an opportunity to comment on a proposed revision to Oklahoma's Regional Haze State Implementation Plan (SIP). The hearing will be held on Monday, May 20, 2013 from 1:00 p.m. to 3:00 p.m., in the 1st Floor Multipurpose Room of the DEQ headquarters, 707 North Robinson Avenue, Oklahoma City, OK 73102.

Under the Oklahoma Clean Air Act (27A OS §§2-5-101 thru 117), DEQ is given the primary responsibility and authority to prepare and implement Oklahoma's air quality management plan, compiled in 40 CFR Part 52, Subpart LL. The DEQ prepared and submitted the original Regional Haze SIP in February 2010, to comply with the requirements contained in the federal Clean Air Act and 40 CFR Part 51, Subpart P, Protection of Visibility. On January 27, 2012, the U.S. Environmental Protection Agency (EPA) partially approved and partially disapproved the Regional Haze SIP (76 Fed.Reg. 81727). In the same action, EPA disapproved portions of Oklahoma's Interstate Transport SIP, as well as the Regional Haze SIP's Long Term Strategy, because they relied on the disapproved portions of the Regional Haze SIP. This revision addresses those disapproved portions of the Regional Haze SIP that relate to the American Electric Power/Public Service Company of Oklahoma (AEP/PSO) Northeastern Power Station Units 3 and 4.

All persons interested in these matters are invited to submit written comments prior to the scheduled close of the public hearing (i.e., 3:00 p.m. on Monday, May 20, 2013) and/or provide oral comments at the public hearing. Persons planning to comment at the hearing may submit a written statement and/or additional information relevant to this matter for inclusion in the record of proceedings of the public hearing. The hearing officer may limit the length of oral presentations to allow all those who wish to provide oral comments an opportunity to do so.

The proposed revision is available on the DEQ website at http://www.deq.state.ok.us/aqdnew/RulesAndPlanning/Regional_Haze. Copies may also be obtained from the Department by contacting Cheryl E. Bradley, Environmental Programs Manager, at (405) 702-4100 or Cheryl.Bradley@deq.ok.gov. Following the close of the hearing and comment period, DEQ will evaluate all comments, and make available a record of the hearing, a copy of all written comments received, a response to comments document, and the finalized Regional Haze SIP Revision on the same webpage when it is ready for submittal to EPA.

Written comments regarding the proposed revision to Oklahoma's Regional Haze SIP should be emailed to Ms. Bradley at Cheryl.Bradley@deq.ok.gov or mailed to:

> Department of Environmental Quality, Air Quality Division
> P.O. Box 1677
> Oklahoma City, Oklahoma 73101-1677
> ATTN: Cheryl E. Bradley

Comments may be submitted by fax to the Air Quality Division, ATTN: Cheryl E. Bradley, at (405) 702-4101.

Should you desire to attend the public hearing but have a disability and need an accommodation, please notify the Air Quality Division three (3) days in advance at (405) 702-4172. For the hearing impaired, the TDD relay number is 1-800-522-8506 or 1-800-722-0353, for TDD machine use only.

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THE LAWTON CONSTITUTION
P. O. Box 2069-L, Lawton, OK 73502 :(580) 353-0620

IN THE ______________________ COURT OF COMANCHE COUNTY, OKLAHOMA

Case No. Haze STATE OF OKLAHOMA, COUNTY OF COMANCHE

Regional Haze

I, James E Cottingham, of lawful age, being duly sworn upon oath, deposes and says: That I am the Business Manager of The Lawton Constitution, a daily newspaper printed and published in the city of Lawton, County of Comanche, and state of Oklahoma, and that the advertisement above referred to, a true and printed copy of which is here unto attached, was published in said newspaper for 1 consecutive days (or weeks), the first publication being on 4/19/2013 ; and the last day of publication being on 4/19/2013

1st Insertion. 4/19/2013

2nd Insertion. . . . . ___/___/20_____

3rd Insertion. . . . . ___/___/20_____

4th Insertion. . . . . ___/___/20_____

Final Insertion. 4/19/2013

That said newspaper has been published continuously and uninterruptedly in said county during a period of one hundred and four consecutive weeks prior to the publication of the attached notice or advertisement: that it has been admitted to the United States mail as second-class mail matter, that it has a general paid circulation, and publishes news of general interest, and otherwise conforms with all of the statutes of the State of Oklahoma governing legal publications.

Signature

SUBSCRIBED and sworn to before me this day of April 19, 2013

Jo Ann Robinson

Notary Public Comm#: 02004515

My commission expires April 27,2014

(Attached Copy of N

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Published in The Lawton Constitution April 19, 2013

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

Notice of Public Hearing and Comment Period for Revisions to the Regional Haze and Interstate Transport State Implementation Plans

The Oklahoma Department of Environmental Quality (DEQ) will hold a public hearing on a proposed revision to Oklahoma's Regional Haze (RH) State Implementation Plan (SIP) and the Interstate Transport SIP. The hearing is scheduled for Monday, May 20, 2013 from 1:00 pm to 3:00 pm in the Multipurpose Room of the DEQ, 707 North Robinson Avenue, Oklahoma City, OK 73102.

DEQ prepared and submitted the original Regional Haze SIP in February 2010, to comply with the requirements contained in the federal Clean Air Act and 40 CFR Part 51, Subpart P, Protection of Visibility. On January 27, 2012, the U.S. Environmental Protection Agency ("EPA") partially approved and partially disapproved the Regional Haze SIP. In the same action, EPA disapproved portions of Oklahoma's Interstate Transport SIP for the 1997 8-hour Ozone and 1997 PM2.5 NAAQS because they relied on disapproved portions of the Regional Haze SIP. This revision addresses those disapproved portions of the RH SIP that relate to the Best Available Retrofit Technology determination for American Electric Power/Public Service Company of Oklahoma Northeastern Power Station Units 3 and 4.

All persons interested in these matters are invited to submit written comments prior to the scheduled close of the public hearing (i.e., 3:00 pm on Monday, May 20, 2013) and/or provide oral comments at the public hearing. Persons the statutes of the State of Oklahoma governing legal publications.

Signature

SUBSCRIBED and sworn to before me this day of

April 19, 2013

Notary Public Comm#: 02004515

My commission expires April 27,2014

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The proposed SIP revisions are available on the DEQ website at http://www.deq.state.ok.us/aqdnew/RulesAndPlanning/Regional_Haze.

Copies may also be obtained from the Department by contacting Cheryl E. Bradley, Environmental Programs Manager, at (405) 702-4100 or Cheryl.Bradley@deq.ok.gov.

Written comments regarding the proposed revision to Oklahoma's Regional Haze SIP should be emailed to Ms. Bradley at Cheryl.Bradley@deq.ok.gov or mailed to:

Department of
Environmental Quality,
Air Quality Division
P.O. Box 1677
Oklahoma City,
Oklahoma 73101-1677
ATTN: Cheryl E. Bradley

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OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
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All persons interested in these matters are invited to submit written comments prior to the scheduled close of the public hearing (i.e., 3:00 pm on Monday, May 20, 2013) and/or provide oral comments at the public hearing. Persons planning to comment may submit a written statement and/or additional information relevant to this matter for inclusion in the record of proceedings of the public hearing. The hearing officer may limit the length of oral presentations to allow all those who wish to provide oral comments an opportunity to do so.

The proposed SIP revisions are available on the DEQ website at http://www.deq.state.ok.us/aqdnew/RulesAndPlanning/Regional_Haze. Copies may also be obtained from the Department by contacting Cheryl E. Bradley, Environmental Programs Manager, at (405) 702-4100 or Cheryl.Bradley@deq.ok.gov.

Written comments regarding the proposed revision to Oklahoma's Regional Haze SIP should be emailed to Ms. Bradley at Cheryl.Bradley@deq.ok.gov or mailed to:
Department of Environmental Quality, Air Quality Division
P.O. Box 1677
Oklahoma City, Oklahoma 73101-1677
ATTN: Cheryl E. Bradley

Comments may be submitted by fax to the Air Quality Division, ATTN: Cheryl E. Bradley, at (405) 702-4101.

Should you desire to attend the public hearing but have a disability and need an accommodation, please notify the Air Quality Division three (3) days in advance at (405) 702-4172.

STATE OF OKLAHOMA,
COUNTY OF OKLAHOMA } SS.

Affidavit of Publication

Carol Davis, of lawful age, being first duly sworn, upon oath deposes and says that she/he is the Classified Legal Notice Admin, of The Oklahoma Publishing Company, a corporation, which is the publisher of *The Oklahoman* which is a daily newspaper of general circulation in the State of Oklahoma, and which is a daily newspaper published in Oklahoma County and having paid general circulation therein; that said newspaper has been continuously and uninterruptedly published in said county and state for a period of more than one hundred and four consecutive weeks next prior to the first publication of the notice attached hereto, and that said notice was published in the following issues of said newspaper, namely:

Okla. Dept. of Environmental Qualit AQD Engineering
11078862 - The Oklahoman
Published on 04/19/2013

Carol Davis

Subscribed and sworn to before me this April 19, 2013

Diannah Featherston
Notary Public

My commission expires April 1, 2017

DIANNAH FEATHERSTON
NOTARY
01004284
EXP. 04/01/17
PUBLIC
STATE OF OKLAHOMA

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TULSA WORLD

P.O. Box 1770 Tulsa, Oklahoma 74102-1770

Published in the Tulsa World, April 18, 2013, Tulsa, OK

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
Notice of Public Hearing and Comment Period for Revisions to the Regional Haze and Interstate Transport State Implementation Plans

The Oklahoma Department of Environmental Quality (DEQ) will hold a public hearing on a proposed revision to Oklahoma's Regional Haze (RH) State Implementation Plan (SIP) and the Interstate Transport SIP. The hearing is scheduled for Monday, May 20, 2013 from 1:00 pm to 3:00 pm in the Multipurpose

Comments may be submitted by fax to the Air Quality Division, ATTN: Cheryl E. Bradley, at (405) 702-4101.

Should you desire to attend the public hearing but have a disability and need an accommodation, please notify the Air Quality Division three (3) days in advance at (405) 702-4172. For the hearing impaired, the TDD relay number is 1-800-522-8506 or 1-800-722-0353, for TDD machine use only.

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OKLAHOMA CITY OK, 73101--167

PROOF OF PUBLICATION

TITLE ______ OKLAHOMA DEQ ENGINEERING DIV ______

STATE OF OKLAHOMA, }
COUNTY OF TULSA, } SS.

AFFIDAVIT:

I, Sandra Mills, of lawful age, being duly sworn, upon the oath deposes and says that he / she is the CLERK of TULSA WORLD, a daily newspaper printed in the City of Tulsa, County of Tulsa, State of Oklahoma, and a bonafide paid general circulation therein, printed in the English language, and that the notice by publication, a copy of which is here to attached, was published in said newspaper for

1 day(s), the first publication being on the 18th day of April, 2013 and

the last day of publication being on the 18th day of April, 2013,

and that said newspaper has been continuously and uninterruptedly published in said county during the period of more than One Hundred and Four (104) weeks consecutively, prior to the first publication of said notice, or advertisement, as required by Section one, Chapter four, Title 25 Oklahoma Session Laws, 1943, as amended by House Bill No. 495, 22nd Legislature, and thereafter, and complies with all of the prescriptions and requirements of the laws of Oklahoma. (The advertisement above referred to is a true and printed copy. Said notice was published in all editions of said newspaper and not in a supplement thereof.)

The advertisement above referred to, a true and printed copy of which is hereto attached, was published in said NEWSPAPER on the following dates, to-wit: **4/18/13**

Said notice was published in the regular edition of said newspaper and not in a supplement thereof.

Publishing Fee	478.54
Notary Fee	
Affidavit	
TOTAL	478.54

Sandra Mills (Signature)

Subscribed and sworn to before me this 22nd day of April, A.D., 20 13

My commission expires 9-10-16 Donna J Lacy
Notary Public

DONNA J. LACY
NOTARY PUBLIC
No. 08009333
EXP. 9/10/2016
IN AND FOR
STATE OF OKLAHOMA

APR 24 2013
AIR QUALITY

P.O. Box 1770 Tulsa, Oklahoma 74102-1770

Ad number: 9025518

OKLAHOMA DEQ ENGINEERING DIV
707 N ROBINSON SUITE 4174
ATTN: L BROOKS KIRLIN
OKLAHOMA CITY OK, 73101--167

PROOF OF PUBLICATION

TITLE _______ OKLAHOMA DEQ ENGINEERING DIV ______________

STATE OF OKLAHOMA, }
COUNTY OF TULSA, } SS.

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Affidavit	
TOTAL	478.54

Subscribed and sworn to before me this 22nd day of April, A.D., 20 13

My commission expires 9-10-16

Notary Public

Published in the Tulsa World, April 18, 2013, Tulsa, OK

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
Notice of Public Hearing and Comment Period for Revisions to the Regional Haze and Interstate Transport State Implementation Plans

The Oklahoma Department of Environmental Quality (DEQ) will hold a public hearing on a proposed revision to Oklahoma's Regional Haze (RH) State Implementation Plan (SIP) and the Interstate Transport SIP. The hearing is scheduled for Monday, May 20, 2013 from 1:00 pm to 3:00 pm in the Multipurpose Room of the DEQ, 707 North Robinson Avenue, Oklahoma City, OK 73102.

DEQ prepared and submitted the original Regional Haze SIP in February 2010, to comply with the requirements contained in the federal Clean Air Act and 40 CFR Part 51, Subpart P, Protection of Visibility. On January 27, 2012, the U.S. Environmental Protection Agency ("EPA") partially approved and partially disapproved the Regional Haze SIP. In the same action, EPA disapproved portions of Oklahoma's Interstate Transport SIP for the 1997 8-hour Ozone and 1997 PM2.5 NAAQS because they relied on disapproved portions of the Regional Haze SIP. This revision addresses those disapproved portions of the RH SIP that relate to the Best Available Retrofit Technology determination for American Electric Power/Public Service Company of Oklahoma Northeastern Power Station Units 3 and 4.

All persons interested in these matters are invited to submit written comments prior to the scheduled close of the public hearing (i.e., 3:00 pm on Monday, May 20, 2013) and/or provide oral comments at the public hearing. Persons planning to comment may submit a written statement and/or additional information relevant to this matter for inclusion in the record of proceedings of the public hearing. The hearing officer may limit the length of oral presentations to allow all those who wish to provide oral comments an opportunity to do so.

The proposed SIP revisions are available on the DEQ website at http://www.deq.state.ok.us/aqdnew/RulesAndPlanning/Regional_Haze. Copies may also be obtained from the Department by contacting Cheryl E. Bradley, Environmental Programs Manager, at (405) 702-4100 or Cheryl.Bradley@deq.ok.gov.

Written comments regarding the proposed revision to Oklahoma's Regional Haze SIP should be emailed to Ms. Bradley at Cheryl.Bradley@deq.ok.gov or mailed to:
Department of Environmental Quality, Air Quality Division
P.O. Box 1677
Oklahoma City, Oklahoma 73101-1677
ATTN: Cheryl E. Bradley

Comments may be submitted by fax to the Air Quality Division, ATTN: Cheryl E. Bradley, at (405) 702-4101.

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From: DEQ Air Quality Division <air-council@deq.ok.gov>
Sent: Thursday, April 18, 2013 11:43 AM
To:
Subject: Proposed Regional Haze & Transport SIP Revision Hearing

DEQ is taking comments and has scheduled a public hearing on a proposed Regional Haze & Transport SIP Revision. The public hearing is scheduled for Monday, May 20, 2013 from 1:00 pm to 3:00 pm at the DEQ headquarters, 707 North Robinson Avenue, Oklahoma City, OK 73102. The comment period is scheduled to end at the close of the public hearing.

Go to the Regional Haze & Transport SIP Revision (2013):
http://m1e.net/c?118762547-3eOkCMAV/Ie4U%4014914658-ObLDFfxZjhzyE

Review the notice for the hearing:
http://m1e.net/c?118762547-TaYRWeOrg0eOs%4014914659-0gI55LNJxuZUk

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Our address:
707 N. Robinson | P.O. Box 1677 | Oklahoma City, Oklahoma 73101

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

Notice of Public Hearing and Opportunity for Comment
Revision to Regional Haze State Implementation Plan
Including Revisions to Affected Portions of the
Interstate Transport SIP for the 1997 8-hour Ozone and 1997 $PM_{2.5}$ NAAQS

The Oklahoma Department of Environmental Quality (DEQ) hereby announces a public hearing and an opportunity to comment on a proposed revision to Oklahoma's Regional Haze State Implementation Plan (SIP). The hearing will be held on Monday, May 20, 2013 from 1:00 p.m. to 3:00 p.m., in the 1st Floor Multipurpose Room of the DEQ headquarters, 707 North Robinson Avenue, Oklahoma City, OK 73102.

Under the Oklahoma Clean Air Act (27A OS §§2-5-101 thru 117), DEQ is given the primary responsibility and authority to prepare and implement Oklahoma's air quality management plan, compiled in 40 CFR Part 52, Subpart LL. The DEQ prepared and submitted the original Regional Haze SIP in February 2010, to comply with the requirements contained in the federal Clean Air Act and 40 CFR Part 51, Subpart P, Protection of Visibility. On January 27, 2012, the U.S. Environmental Protection Agency (EPA) partially approved and partially disapproved the Regional Haze SIP (76 Fed.Reg. 81727). In the same action, EPA disapproved portions of Oklahoma's Interstate Transport SIP, as well as the Regional Haze SIP's Long Term Strategy, because they relied on the disapproved portions of the Regional Haze SIP. This revision addresses those disapproved portions of the Regional Haze SIP that relate to the American Electric Power/Public Service Company of Oklahoma (AEP/PSO) Northeastern Power Station Units 3 and 4.

All persons interested in these matters are invited to submit written comments prior to the scheduled close of the public hearing (i.e., 3:00 p.m. on Monday, May 20, 2013) and/or provide oral comments at the public hearing. Persons planning to comment at the hearing may submit a written statement and/or additional information relevant to this matter for inclusion in the record of proceedings of the public hearing. The hearing officer may limit the length of oral presentations to allow all those who wish to provide oral comments an opportunity to do so.

The proposed revision is available on the DEQ website at http://www.deq.state.ok.us/aqdnew/RulesAndPlanning/Regional_Haze. Copies may also be obtained from the Department by contacting Cheryl E. Bradley, Environmental Programs Manager, at (405) 702-4100 or Cheryl.Bradley@deq.ok.gov. Following the close of the hearing and comment period, DEQ will evaluate all comments, and make available a record of the hearing, a copy of all written comments received, a response to comments document, and the finalized Regional Haze SIP Revision on the same webpage when it is ready for submittal to EPA.

Written comments regarding the proposed revision to Oklahoma's Regional Haze SIP should be emailed to Ms. Bradley at Cheryl.Bradley@deq.ok.gov or mailed to:

Department of Environmental Quality, Air Quality Division
P.O. Box 1677
Oklahoma City, Oklahoma 73101-1677
ATTN: Cheryl E. Bradley

Comments may be submitted by fax to the Air Quality Division, ATTN: Cheryl E. Bradley, at (405) 702-4101.

Should you desire to attend the public hearing but have a disability and need an accommodation, please notify the Air Quality Division three (3) days in advance at (405) 702-4172. For the hearing impaired, the TDD relay number is 1-800-522-8506 or 1-800-722-0353, for TDD machine use only.

Appendix V

Comments Received

Appendix V, Comments Received, is in a separate document

Appendix VI

Hearing Transcript, Sign-in Sheets, and Hearing Certification

O K L A H O M A
DEPARTMENT OF ENVIRONMENTAL QUALITY

STEVEN A. THOMPSON
Executive Director

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

MARY FALLIN
Governor

June 14, 2013

Mr. Ron Curry, Regional Administrator (6RA)
U.S. Environmental Protection Agency – Region VI
1445 Ross Ave., Suite 1200
Dallas, TX 75202-2733

Subject: Certification of May 20, 2013 Hearing
Regional Haze State Implementation Plan (SIP) and Interstate Transport SIP for 1997 8-Hour Ozone and 1995 PM2.5 NAAQS Revision

Dear Mr. Curry:

The Oklahoma Department of Environmental Quality ("DEQ") recently conducted a public hearing concerning a proposed Revision to the Regional Haze State Implementation Plan (SIP) *Including Revisions to the Affected Portions of the* Interstate Transport SIP for the 1997 8-Hour Ozone and 1997 $PM_{2.5}$ NAAQS. The public hearing was held on May 20, 2013 from 1:00 to 3:00 p.m. in the 1st Floor Multipurpose Room of the DEQ headquarters, 707 North Robinson Ave., Oklahoma City, Oklahoma, 73102.

On behalf of DEQ, I certify that the hearing was conducted in accordance with the information provided in the public notice and requirements of the laws and constitution of the State of Oklahoma and 40 C.F.R. § 51.102.

Sincerely,

Eddie Terrill
Division Director
Air Quality Division

ET:CB

* * * * *

TRANSCRIPT OF PROCEEDINGS
OF THE REVISION TO THE
REGIONAL HAZE SIP
INCLUDING REVISIONS TO AFFECTED
PORTIONS OF THE INTERSTATE
TRANSPORT SIP FOR THE
1997 8-HOUR OZONE
AND 1997 PM2.5 NAAQS
ON MAY 20, 2013, AT 1:00 P.M.
IN OKLAHOMA CITY, OKLAHOMA

* * * * *

PRESENT

(See sign-in page)

PROCEEDING

MS. BOTCHLET-SMITH: Before we get started, I want to remind everyone to please turn off your cell phones or put them on silent.

Good afternoon. I'm Beverly Botchlet-Smith, Assistant Director of the Air Quality Division, and I'm going to serve as Protocol Officer for today's hearing.

The hearing will be convened by the Department of Environmental Quality in compliance with Title 40 of the Code of Federal Regulations Part 51 as well as the authority of Title 27A of the Oklahoma statutes, Sections 2-5-101 through 2-5-117.

DEQ is given the primary responsibility and authority to prepare and implement Oklahoma's Air Quality Management Plan, compiled in 40 CFR Part 52, Subpart LL.

Notices for this hearing were published in the Tulsa World Newspaper on April 18, 2013, and in

the Lawton Constitution and the Oklahoman newspapers on April 19, 2013. Notice was also provided through a posting on the DEQ website on April 18, 2013.

This hearing is being conducted for the purpose of receiving comments on the proposed revision to the Regional Haze State Implementation Plan, including revisions to portions of the Interstate Transport SIP for the 1997 8-hour Ozone and the 1997 PM2.5 NAAQS as provided in 40 CFR Section 51.102 and the U.S. Environmental Protection Agency regulations.

The proposed plan revision has been available for inspection by the public since April 18, 2013.

DEQ will accept written and oral comments on the proposed SIP revision until the close of today's hearing. If you wish to make a statement today, it is very important that you complete the form provided

at the registration table. You will be called upon at the appropriate time and we ask that all commenters please come to the podium to make your comments and state your name and affiliation for the record.

It will be necessary to limit the time for each commenter to make his or her oral comments to five minutes. This is so all who wish to speak today will have the opportunity to do so. Any comments received prior to the close of this hearing will be made part of the hearing record and considered in developing the Agency's submission to EPA; however, DEQ staff will not be providing responses to any comments during the hearing. All comments and any Agency responses will be included in the SIP revision submitted to EPA.

At this time, we would like to proceed with the hearing. Mr. Robert Singletary, who is the Environmental Attorney Supervisor, will give DEQ's presentation.

Rob.

MR. SINGLETARY: Ladies and gentlemen, good afternoon. Today I plan to provide some general background and a brief introduction to the State Implementation Plan revision that the Agency is receiving comments on today; however, first I have been asked to mention that the DEQ did recently receive a request from the Oklahoma Attorney General's office to delay today's public hearing based on the possibility of some new information related to PSO's 2012 Integrated Resource Plan.

After consultation with the Secretary of Environment's office and in light of the State's obligations under a Settlement Agreement, that I'll discuss in a little bit more detail in just a moment, the decision was made to proceed with today's public hearing as scheduled.

The purpose of today's public

hearing is to solicit public comment on the proposed SIP revision. All relevant comment that is received, including any new information, will be considered and will be part of the decision making process.

Additionally, in regard to any new information related to an Integrated Resource Plan, DEQ recognizes that the Oklahoma Corporation Commission is the State agency with the authority and the expertise to evaluate such a plan and has full confidence that the Corporation Commission will appropriately address any information that is presented in that regard.

So to begin with the background on the Regional Haze SIP. The Federal Clean Air Act establishes a national goal of returning Class I Federal areas to their natural visibility conditions. Class I areas, for those of you who don't know, are national parks, national

wildlife areas and national wilderness areas.

In Oklahoma, we only have one such area and that is the Wichita Mountains National Wildlife Refuge located in Comanche County. Even though Oklahoma has only one of these areas in the State, there are several Class I areas located in nearby states that are impacted by the emissions from sources that are located in Oklahoma.

As directed by Congress, EPA regulations require States to develop, and submit for approval, Regional Haze State Implementation Plans that are designed to reduce pollutants that cause visibility impairment and to return these Class I federal areas to their natural visibility conditions by 2064.

As part of the SIP development process, EPA regulations mandate that States require certain older facilities that have significant

sulfur dioxide, nitrogen oxide, or particulate matter emissions, to install and operate what is referred to as BART, which stands for the Best Available Retrofit Technology.

Only sources that meet certain criteria established in Federal regulations and which cause or contribute to visibility impairment at a Class I area are subject to these BART requirements.

DEQ determined that there are only 20 sources in Oklahoma that meet these Federal criteria. Of those 20 sources only six were determined to significantly cause or contribute to visibility impairment at a Class I area. What that means is there are only six sources located in Oklahoma that are subject to these BART requirements. Three of the sources are coal-fired electric generating facilities. One of these is owned by PSO. The PSO facility at issue here is the Northeastern Power

Station that is located in Rogers County and includes two coal-fired units.

Several years ago, the DEQ developed a Regional Haze SIP revision which included BART determinations for these units. The original SIP revision was submitted to EPA back in February of 2010.

In December of 2011, EPA approved much of Oklahoma's original submission; however, there were some significant aspects of that plan that were disapproved, including specific BART determinations that related to these coal-fired units and some emission limits that were associated with those BART determinations.

Along with that disapproval, EPA promulgated a Federal Implementation Plan, or a FIP, for these coal-fired units. The FIP essentially required the installation and the operation of dry flue gas desulfurization which is a control

technology that's commonly referred to as a "dry scrubber". These dry scrubbers were to be installed within 5 years of promulgation of the FIP.

The disapproval and the FIP have been challenged by the Oklahoma Attorney General, by OG&E, and by PSO. These judicial challenges are currently pending before the 10th Circuit Court of Appeals.

At the same time, Secretary Sheerer, the Oklahoma Secretary of Environment, and DEQ, have worked together with PSO to develop a practical alternative to the requirements of the F1P, at least as they apply the coal-fired units that are operated by PSO.

The framework for this alternative formed the basis of a settlement agreement that was entered into by the Secretary of Environment, by DEQ, by PSO, by EPA, by the DOJ, and by the Sierra Club.

As part of that settlement

agreement PSO's judicial challenge to EPA's FIP is being held in abeyance pending the implementation of the agreement.

The proposed SIP revision is consistent with the terms of that settlement agreement and generally provide PSO with the flexibility of utilizing a combination of different emission control technologies such as dry sorbent injection, activated carbon injection, and fabric baghouses on one of their units; as well as an incremental decrease in the capacity utilization of that unit. And it also includes reductions in the operating life span of each of the coal-fired units.

In essence, the proposal provides PSO with a more holistic approach that is designed to meet not only the Regional Haze requirements, but also to assist the company in meeting new regulatory challenges that are currently facing the utility

industry.

In addition to satisfying Oklahoma's Regional Haze SIP obligations for these two PSO units, this SIP revision is also intended to satisfy Oklahoma's Interstate Transport SIP obligations as it relates to these two coal-fired units.

On March 20, 2013, Secretary Sherrer submitted this proposed SIP revision to EPA for approval along with a request for parallel processing. As required by law, the proposed SIP revision has been available for public comment for more than 30 days. Notice, again, was published on April l8th in the Tulsa World, and April 19th in the Oklahoman and the Lawton Constitution. Again, the public comment period is going to close at the conclusion of today's public hearing.

Once these comments have been

considered and revised, a final SIP submission will be submitted to EPA for review. As part of that review process EPA will provide a separate public comment period, and a notice, of which, should be provided in the Federal Register.

Again, if you would like to provide oral comment today, please fill out one of the comment forms on the table located outside the room.

With that, I believe, we are ready to proceed with the hearing.

MS. BOTCHLET-SMITH: Secretary Sherrer.

SECRETARY SHERRER: Good afternoon. Thank you for the opportunity to provide comments today.

My name is Gary Sherrer, and I service as Oklahoma Secretary of the Environment.

In March of 2011, the Environmental Protection Agency, EPA, announced its intention to partially

approve and partially disapprove Oklahoma State Implementation Plan, the SIP, to come into compliance with the Regional Haze Rule, and to promulgate a Federal Implementation Plan, the FIP. Within days I was asked by Governor Mary Fallin to work with the affected utilities to try to develop an Oklahoma-based solution that achieved regulatory compliance, while also addressing concerns of the utilities, recognizing the unique nature of their generation structure and their customer needs.

AEP/PSO contacted my office and expressed an interest in working to develop an alternative to the FIP. AEP/PSO wished to work on a plan to achieve compliance with the Regional Haze Rule and a number of other air rules that were at various stages of development.

For over a year my staff and I worked with representatives of AEP/PSO and the Oklahoma Department

of Environmental Quality to develop an Oklahoma plan. This plan was memorialized as the final settlement agreement that was announced by Governor Fallin in April of 2012 and formally signed last fall, which called for the development of the new SIP for AEP/PSO that is being considered today.

I am pleased to say that this settlement agreement that was reached allows AEP/PSO the ability to chart their own course and identify emission control technologies that work best for their plant, rather than installing dry scrubbers as called for in the FIP, while also providing regulatory certainty in planning for compliance with future air rules.

After extensive modeling of the Oklahoma plan, we have been able to determine that these technologies provide for comparable results and meet all requirements set out in the

Regional Haze Rule. This Oklahoma-based plan and the resulting SIP were carefully crafted and vetted to be in both technical and legal compliance with the Clean Air Act and to serve as the replacement for the FIP. This SIP allows for compliance, while also putting AEP/PSO on a path that works best for them and their customers.

In addition to meeting Regional Haze requirements, the settlement agreement also is designed to bring AEP/PSO into compliance with the Mercury and Air Toxic Rules and various other air rules.

Once again, thank you for the opportunity to provide comments today.

In closing, I want to emphasize that I believe that the proposed SIP is in full compliance with the Clean Air Act and the signed settlement agreement and I look forward to it being delivered to EPA for their review.

And to make a statement, on a personal note, this agreement took over a year for us to work out with EPA. It was a very hard settlement to work out, but I honestly believe that this settlement is in the best interest of AEP/PSO and also the customers of Oklahoma. There may be some who will give comments today and possibly try to blur some compliance rules of cost, which is clearly under the jurisdiction of the Corporation Commission and the environmental rules which clearly are to be determined through this setting.

So, again, thank you so much for the privilege of presenting these comments today.

MS. BOTCHLET-SMITH: Mr. John Dirickson.

MR. DIRICKSON: I was hoping I would be last. My name is John Dirickson. I'm from the City of Oologah. Public Service has been a

good partner with the City of Oologah over the years. They have been a reliable and trusted partner with the City and we -- we have a great school, which we feel like that Public Service -- they didn't build it but the tax-base that they generated certainly did. We have an ambulance, fire department, and things of that nature that just -- of course, we do believe that Public Service has to comply with Environmental Protection Agency rules and regulations. However, it would be my concern, also, that eventually the rates would get so high that they would affect communities like ours, which is small and has a lot of retired people. So be that as it may, Public Service has certainly -- and the fact of the matter is I'm a retired PSO employee and I know that over the years that they did everything that they could to comply with every environmental standard

that came out. In fact, some of them fluctuated so much it was almost impossible to keep up with them. If we continue on at a rate like that it would be very difficult even for them to comply with the ones that has been set before you today. But Public Service has been a -- a good partner for the City of Oologah and they are making sure that its customers have a sufficient supply of power now and in the future. No one else has the legal obligation to serve PSO customers and no one else will be accountable -- held accountable. If sufficient generation is not available and customers lights go dark, PSO has fulfilled its obligation in a cost effective way for 100 years. And this environmental compliance plan represents the company's collective approach to meeting that obligation at this time.

So I guess you can assume from

my statement here that we are for and in support of Public Service and their rehab plan, as they have a plan with the Environmental Protection Agency. Thank you.

MS. BOTCHLET-SMITH: Thank you. Mr. Dirickson, did you also have written comments for me?

MR. DIRICKSON: No.

MS. BOTCHLET-SMITH: Okay. Thank you.

MR. DIRICKSON: They're all (inaudible).

MS. BOTCHLET-SMITH: Mr. Tom Schroedter.

MR. SCHROEDTER: Good afternoon. My name is Tom Schroedter. I'm the Executive Director of Oklahoma Industrial Energy Consumers, otherwise known as OIEC, an unincorporated association of large consumers of energy with facilities located throughout Oklahoma. OIEC consists of over 20 member companies that have operations throughout the State. Many of our members are engaged in energy price-sensitive industries such as pulp and paper, cement, refining, glass, industrial gases, and film. OIEC Members employ thousands of Oklahomans.

I'm here today to represent OIEC and express OIEC's opposition to the revised State Implementation Plan or SIP that has recently been developed and proposed by the Oklahoma Department of Environmental Quality. OIEC has also filed comments in this case. They are already part of the public record so my remarks this afternoon are intended to summarize those comments.

Initially I want to say that OIEC finds itself in an awkward position today in opposing DEQ's revised SIP. Our members work closely with DEQ and hold the Agency and its staff in high regard. However, and much to our dismay, DEQ

has developed a SIP which is both technically and legally flawed and which will result in a rate shock for PSO rate payers. Therefore, OIEC must voice its strong opposition to the SIP.

Before I list the reasons why we oppose you should know that the SIP is based on a settlement agreement among PSO, EPA, Sierra Club, and others that was developed and consummated with virtually no input from PSO's customers who are being asked to pay for the billions of dollars of implementation cost of the plan. If approved and implemented this SIP will result in the largest single rate increase, to my knowledge, ever, for PSO's customers in the company's 100 year history. You cannot overlook that or dismiss that. To ensure economic growth and prosperity in our state PSO's rates must remain at their lowest reasonable level. It's

critical that industries remain competitive within industries elsewhere, outside Oklahoma, so that our state's economy will grow and prosper and not shrink.

As I stated, the DEQ revised SIP is technically and legally deficient for a number of reasons.

First, the proposal to retire both of PSO's coal-fired generating units simply cannot be the Best Available Retrofit Technology pursuant to the rules of the EPA. In fact, BART -- EPA's BART guidelines provide that BART cannot be conversion of a coal plant to natural gas because conversion is not retrofitting. For similar reasons, mandating the early retirement of a coal generating facility to achieve emission reductions cannot be BART. Not only would there be no retrofitting, there's no facility. Accordingly the DEQ SIP, which requires retirement of the units, is

not BART.

Second, even if the mandate of the early retirement of PSO's coal units could be considered as BART it was err not to consider cost of compliance as required by federal regulations. The omitted compliance cost of the revised SIP include the cost -- must include the cost of replacement capacity in energy which result from the retirement of these coal units. The DEQ SIP ignored the replacement and capacity energy costs arising from these requirements. So the cost of the DEQ SIP is understated by around 262 million dollars a year. If you add that 262 million to the DEQ's 25 million dollar cost estimate, you get a total compliance cost estimate of 287 million dollars per year. That amount is more than six times the cost estimate for the scrubber retrofit option which is set forth in the EPA FIP.

MS. MARSHMENT: Thirty seconds.

MR. SCHROEDTER: So to conclude, we would -- we would state that the SIP is technically deficient; it's legally deficient. It does not meet the criteria established by EPA for approval as BART or as an alternative to BART, and is clearly not in the interest of PSO's rate payers.

I might add that the DEQ SIP never published or posted the entire settlement agreement that was an exhibit -- should have been an exhibit to the -- to DEQ's filing. That also may be a violation of the Open Meeting Act which means the DEQ must withdraw the proposal.

So in the view of OIEC the SIP must be redrawn -- withdrawn and reconsidered at a later date. Thank you.

MS. BOTCHLET-SMITH: Thank you, Mr. Schroedter. Did you have

written comments to provide today?

MR. SCHROEDTER: Yes, I do. We submitted our written comments on Friday, I believe.

MS. BOTCHLET-SMITH: All right. Thank you, very much.

Mr. Bud Ground.

MR. GROUND: Good morning. I'm Bud Ground. I'm Manager of Governmental and Environmental Affairs for Public Service Company of Oklahoma. And I have some comments, but due to the shortening of time I'm also going to present in the testimony a document that will supplement what I'm going to say.

Speaking of our revised SIP, you've heard it much more eloquently than I can speak. Rob Singletary described the issue. Secretary Sherrer described the issue. And to add on to that I'd like to just say that PSO's environmental compliance plan, which is what we call this plan and the revised State

Implementation Plan are an Oklahoma solution. As the Secretary mentioned, the State received a Federal Implementation Plan and not only did we know, the DEQ know, the Governor knew, the Secretary of Energy, and the Secretary of Environment knew that we could come up with a better plan than to just accept what the Federal Implementation Plan required us to do. So we started working at the invitation of the Secretary of Energy and Secretary of Environment; we started working with them to develop the Oklahoma solution. And we knew that we could come up with something that was better, lower cost, better for our customers, better for our company than installing 800 million dollars or so worth of control equipment on 30-plus-year-old coal units. And so we entered into this discussion and working on a plan, which we considered a no-regret

situation and if it got to a point where it was not good for us we could get out of it. And we took -- we developed this plan with the DEQ, and Secretary of Environment, Secretary of Energy, with the consultation even of the Attorney General and the Governor at the time, and we took that plan to EPA. Now EPA -- this was not a plan that they, some might say forced on our company to do, this is something that we took to them as a plan and then negotiated with them on the results.

So when this -- the FIP was actually -- it was in March of 2011 when the FIP was actually submitted and partially approved and partially disapproved, and we took that -- the approval part of that and we started on our NOx controls for, not only that coal-unit or coal units, but also the gas units that were affected by it.

And through this, PSO chose to

participate in this plan. It wasn't something that we were forced to do, it was something that we were asked to do and decided this was the best for our company. And this worked out that the PSO plan -- when we took it to EPA for -- and started into negotiations it was difficult at first for them to understand how this all would work on a negotiated issue but we worked as, Secretary Sherrer said, for over a year and finally had enough discussions where they saw it was -- met the requirements of BART, met the requirements of the SIP. And we also wanted to make sure that it not only met the requirements of the Regional Haze Rule but, for us, for PSO, it had to also meet the requirements of the mercury and air toxics rule which is just being promulgated. So we wanted to make sure that we didn't have to come back and do any further control equipment on units that through this

plan were going to be retired in a specific amount of time. We made sure that it was not only a Regional Haze plan but it was a plan that met NAAQS as well; and in taking care of those two, it also would take care of many other issues -- air and water issues and solid waste issues that would be coming up in the very near future within the EPA.

This environmental control plan provides for environmental benefits while ensuring the continued reliability and mitigating risks for future environmental regulations, as I just spoke. And instead of spending, like, the 800 million dollars, we would spend about 650 million less than that to comply with these regulations. And as you know we plan to retire these units in 2016, and then 2026 on the second unit. And this transition from coal to gas will reduce not only our SO2 emissions but our particulate

emissions and the NOx emissions as well. So not only is this environmentally responsible, it is a PSO and Oklahoma solution to these requirements. It's also the best tool for our customers. This plan does avoid very large capital costs on units that are greater than 30 years old.

And as a last comment, I'll add to what Mr. Dirickson said. PSO, on the 29th of this month, will be 100 years old as an Oklahoma Corporation. So we actually were in the state prior to that but we will be a low cost, low provider -- (inaudible) low-cost provider for over 100 years in Oklahoma.

Thank you.

MS. BOTCHLET-SMITH: Thank you. Did you have written comments?

MR. GROUND: I do.

MS. BOTCHLET-SMITH: Bob Rounsavell.

MR. ROUNSAVELL: My name is

Bob Rounsavell. I'm here today as a resident of Oologah, Oklahoma. I am also a Sierra Club Member and as President of the Carrie Dickerson Foundation.

I think this agreement reached between PSO and EPA, Oklahoma, and Sierra Club is a great start in improving our air quality. Although I wish that the second coal-fired unit could be phased out much sooner than 2026. I realize, none the less, the most important significance is the collaboration here by these stakeholders in reaching this agreement.

The agreement will bring about environmental benefits resulting in significant health benefits. By 2026 sulfur dioxide emissions from the northeastern plant will be eliminated. Elimination of mercury and other toxins from burning coal will also be eliminated and will help improve health conditions, especially for Oologah residents. Mercury may very well have been the cause of my wife's colon cancer after residing for a decade only a mile from the two coal units and half a mile from the train tracks with the many coal trains we have every week. Fortunately, her indomitable spirit prevailed.

And then we have carbon dioxide, CO2. Reducing CO2, which this agreement will accomplish, is going to greatly improve chances for human survival. Unfortunately, many are still in denial about this well-researched phenomenon of global warming, which CO2 is the principal reason.

Economically the PSO rate plan is most beneficial as it offers the lowest impacts on commercial, industrial and residential customers.

I understand that some large industrial users want scrubbers installed so the coal units can

continue operating until 2041, thus, extending the dirty emissions while reaping high profits.

The plan paves the way for solving public health concerns about pollution from burning coal. I live near the northeastern plant and it's high time my health was protected.

ODEQ should approve the PSO plan. It's cleaner, it will support Oklahoma jobs, and it will keep ratepayer money closer to home. If you live in Oologah, own a white motor vehicle and leave the windows in your house open, then you have problems. I can go outside many days and write my name on my white car. Leaving the windows open for fresh air invites a whole bunch of coal dust inside the house. This soot coming into the house is not the same as normal dust; it's highly toxic. This plan is a necessary start to improving air quality for our future.

Carrie Dickerson saw the need for cleaner, renewable energy sources which we have in abundance in our state. She spent much of her life promoting clean, renewable energy, especially wind power.

So as President of the Carrie Dickerson Foundation and on its behalf, I thank PSO, Oklahoma, EPA and Sierra Club for having the courage and foresight to change the status quo. We'll all live longer because of this proposed plan. Thank you for this opportunity.

MS. BOTCHLET-SMITH: Mr. Jon Laash.

MR. LAASH: Thank you. I'm here on behalf of myself and Cheryl Bought (phonetic), and we're here for Dogwood Energy, LLC.

In addition to the written comments we've submitted, and another copy of which I'll submit at the conclusion, I just briefly want to summarize the written information

we've submitted.

Dogwood Energy is a generator of electric power, and appears today in support of the proposed Regional Haze SIP revision.

Dogwood submits that that the SIP fully complies with the federal requirements to reduce regional haze and interstate pollution from the Northeastern Coal-fired Plant in Oologah, Oklahoma. The requirement to retire one Northeastern plant along with retrofits and a study ramp done of capacity at the other is a more cost-effective solution than requiring the installation of expensive scrubbers on both units.

The SIP revision is consistent with the State of Oklahoma's energy plan which prioritizes the increased use of Oklahoma's energy resources such as wind, and natural gas, and the protection of public health in the environment.

The SIP revision encourages use

of Oklahoma resources and the elimination of Northeastern's coal plants, coal imports, by 2026. Transitioning from coal to gas, wind, energy efficiency, and man response, also has significant benefits for the overall reliability of the energy grid.

As the amount of wind in Oklahoma and southwest power pool rises, fossil generation will need to ramp up production and down more -- up and down more frequently and shutdown for various periods of time during high wind production. The switching option, the result in plants better suited to integrate with variable wind generation both technically and economically.

Oklahoma has the discretion to choose the best option so long as it has considered all relative factors considered consistent with the BART Guidelines and provided a justification.

Dogwood believes DEQ correctly and justifiably chose the alternative that provides for the gradual phase-out of the Northeastern coal units.

Dogwood supports the SIP revision and urges DEQ to promptly move forward with finalizing and implementing the rule.

Thank you.

MS. BOTCHLET-SMITH: Mr. Lee Paden.

MR. PADEN: Good afternoon. My name is Lee Paden. I represent an association called the Quality of Service Coalition who consist of consumers who primarily receive electric service from Public Service Company of Oklahoma. Majority of the members of our association are located in northeastern Oklahoma but include members living in other parts of the State as well.

Our membership includes realtors, home and commercial

builders, trade associations, cities, towns where PSO provides electric service, local banks, businesses and individuals.

Our organization is concerned with service quality, the impact of rates on attraction and retention of new and existing businesses and the continued growth of our state.

I would be remised if I didn't echo the comments of Mr. Schroedter concerning the Department. I've had the pleasure of serving as a part of this Department's organization from its inception until 2004. It's composed of very competent and able people and my remarks should not be directed toward any particular individual.

What we're here today to do is to try to provide a technical analysis, if you will, of the proposal that's been made and the Quality Coalition is going to do that.

We are opposed to the Proposed

Regional Haze SIP Revision and in submitting the following comments, we strongly suggest that the proposal does not conform to Federal and State statutory and regulatory requirements related to Regional Haze and, thus, should be rejected as a reasonable approach to implement control technologies to achieve those goals and objectives.

This proposal's attempt to amend a previous Oklahoma State Implementation Plan filed by ODEQ in February of 2010, which proposed BART for six generation facilities in Oklahoma. Four of those generation facilities, operated by Oklahoma Gas and Electric, and two of the facilities which are the subject of this proposal by PSO. Public Service Company of Oklahoma is an affiliate of American Electric Power, which owns public utilities operating in Oklahoma, Texas, Louisiana, Arkansas, Indiana, Michigan, Ohio, Kentucky,

Virginia and West Virginia.
It is important to point out that the February 2, 2010 ODEQ Regional Haze Implementation Plan Revision was filed using -- and this is a quote from the document -- incomplete visibility data for 2001, completed data for 2002-2004 and provisional data for 2005 and 2006. Baseline conditions represent the average of 2002-2004 data.
In addition, ODEQ bases it long-term strategy on an identified baseline emissions inventory that is also a 2002 inventory.
ODEQ is required to consider and address the anticipated net effect of visibility resulting from changes projected in point, area, and mobile source emissions by 2018. As explained in the original SIP on Page 91, dated February 2, 2010, the changes anticipated to occur will result from population growth, land management evolution, air pollution

control, and development of industry, energy and natural resources. There is no indication in the most recently filed Proposed Regional Haze Implementation Plan Revision, that DEQ used modeling data that contains more updated emissions inventory information. To establish emissions projection in 2018 from the 2002 data, ODEQ, used CENRAP modeling experience and developed an estimated inventory for 2018. Quality of Service Coalition respectfully suggests that the use of data that is outdated is inappropriate, it requires additional data be supplied and would suggest that more current emissions data used in modeling to determine that the projected regional haze in 2018 regional haze statutes is vitally important to the consideration of whether or not this SIP be adopted or not.
Only recently EPA recognized in a decision that they're rendering on

an Arizona submission, that updated Regional Haze submission data is important and is necessary in a 2008 inventory information submitted by that agency.
The settlement incorporates a variety of other things but I'd like to, especially, address one issue. Reasonable progress goals require ODEQ to consider five factors in determining reasonable progress.
Those five factors are cost of compliance, time necessary for compliance, energy effects of compliance, non-air quality environmental effects, and remaining useful life.
It is Quality of Service's opinion that factor number 3, energy effects of compliance, if considered at all, did not factor into consideration of that requirement.
MS. BOTCHLET-SMITH: Mr. Paden, your time is up. Can you summarize very quickly?

MR. PADEN: Okay. I will be happy to.
Replacement energy when an existing facility is retired is essential to provide services to PSO customers. That was not factored into this process and should be.
We suggest that the Proposed Regional Haze Plan does not meet the statutory or regulatory requirements necessary for approval for this proposal, and we recommend that it be rejected in the best interest of Oklahoma customers of PSO, the state of Oklahoma and all Oklahoma citizens. Thank you.
MS. BOTCHLET-SMITH: Do you have written comments?
MR. PADEN: Yes.
MS. BOTCHLET-SMITH: Thank you, sir.
Ms. Susan Schmidt.
MS: SCHMIDT: My name is Susan Schmidt, I'm a member of the Sierra Club, and I support the SIP.

In Oklahoma we are fortunate to have an excellent wind corridor which allows us to become a leader in wind energy production. And we have natural gas which can quickly ramp up power to back up wind production. It makes no sense for Oklahoma to spend 63 million dollars a year to import coal when wind is safe, non-polluting, and the wind itself is free. When we send our money to Wyoming to buy coal, we import more than coal. We import asthma, bronchitis, heart attacks and death.

I would have carried in 200 pounds of sugar today to demonstrate the amount of mercury being released in Oklahoma's environment every year from the Northeastern unit alone. But 200 pounds is too great a burden for me to carry. It is also too great a burden for Oklahoma's environment to carry. Just one gram of mercury is enough to contaminate a 20-acre lake. The mercury threat

from burning coal is not hypothetical. The fish are already poisoned in many of Oklahoma's lakes.

The Clean Air Act was signed into law in 1963 to protect us, the people. Some people complain that when PSO is required to comply with the Clean Air Act, the cost of doing business responsibly will increase customer costs. In its plan to resolve the immediate haze problem by shutting down the Northeaster unit, PSO estimates customers rates will increase 9.7 percent. That 9.7 percent means less than a twelve dollar increase per month for a family like mine.

Burning coal is largely responsible for global warming. And global warming is responsible for the increases in extreme weather we have seen across Oklahoma and the country. My home insurance paid $38,000 to replace the roof on my home, a room on our shop, a garage door and some

guttering in 2010.

We were lucky that, one, we were not hurt; and, two, that all the damage occurred in one claim. Our friend's damage occurred in three separate storms close together, which resulted in their insurance being cancelled even though they had been with the company for many years without claims. I called my long-time insurance agent last week. He said that previously, "thunderstorms meant thunder, wind, rain and maybe pea-size hail". Now he said, almost every thunderstorm brings large hail and tornadoes. Yesterday we watched television for hours as multiple huge E4 tornadoes, at least one a mile wide, crossed Oklahoma.

I say it's time we stop using coal. It's better to spend a relatively few dollars more for wind, natural gas, and solar, rather than repeatedly paying thousands of

dollars to repair damage caused by a world using too much coal.

And while the fear and worry for loved ones is fresh in your mind from yesterday's storms, remember Hurricane Sandy last fall. Sandy cost this nation billions of dollars and lives lost. The increased rates people gripe about today are chump change compared to the consequences we're seeing for years of harm to the environment. It's time we factor in the financial, medical, and emotional consequences of global warming.

PSO needs to follow-through with the SIP to retire the Northeastern unit by 2016 as agreed and ramp up its plans to transition away from coal. It's past time that all utility companies embrace clean energy. Thank you all.

MS. BOTCHLET-SMITH: Jamie Maddy.

MR. MADDY: Thank you. My

name is Jamie Maddy, Director of Regulatory Affairs at Chesapeake Energy, and I submit the following comments in support of the Oklahoma Department of Environmental Quality's proposed revision to Oklahoma's Regional Haze State Implementation Plan.

Under the Oklahoma Clean Air Act, DEQ is given primary authority and responsibility for preparing and implementing the air quality management plan for our state. DEQ originally prepared and submitted its Regional Haze SIP in February of 2010. On January 27, 2012, EPA accepted the majority of Oklahoma's state plan, with a limited portion of the SIP rejected because of the emission limits related to sulfur dioxide.

Consequently, EPA's FIP to address these defects established BART as Dry Flue Gas Desulfurization with Dry Absorber on PSO's affected

units at Northeastern.

However, at the encouragement and request of the Oklahoma Secretary of Environment and the Oklahoma Secretary of Energy, and others, PSO initiated comprehensive discussions with state officials to develop an Oklahoma centric plan for known federal requirements affecting electric generating units.

In DEQ's BART Determination, it was concluded that, quote, these reductions will help to address local formation and interstate transport of ozone and reduce the contribution of greenhouse gasses and mercury deposition from electricity generation in Oklahoma. This approach provides consistency and predictability to the process. The technology at issue, and the overall compliance plan, has been adequately vetted by Oklahoma experts, other air engineers, EPA, justice, and will meet the objectives necessary to

comply with BART and related Regional Haze requirements. Accepting this proposal for submission to EPA allows PSO to plan for compliance and address its long-term generation needs.

In the original Regional Haze Agreement, it was acknowledged that in the event EPA rejected the SIP as it ultimately did, a BART alternative would result in switching one coal-fired unit to natural gas.

Additionally, EPA has long acknowledged that greater utilization of natural gas is indeed a means for utilities across the U.S. to meet BART requirements and other obligations under federal law.

Chesapeake Energy, one of the nation's largest producers of natural gas, strongly believes the resource to be the most viable, economic, and immediately available solution to meet BART.

The First Amended Regional Haze

Agreement will, in part, result in greater utilization of natural gas and, consequently, will have a significant positive impact on our economy and our industry. Given the supply and availability of natural gas in Oklahoma, the use of gas-fired power generation will not result in significant rate increases as compared to installing controls.

I am confident that all in this room recognize the importance of a strong natural gas and oil industry. And in our state, thankfully, Oklahoma consistently ranks third after Texas and Wyoming in the production of natural gas, with production projected to continue to increase significantly over the next decade and beyond.

Oklahoma's Energy Plan calls for a strategy that increases reliance on Oklahoma resources for power generation, and according to the plan helps preserve Oklahoma's relative low cost of energy and electricity while simultaneously strengthening the economy and our air quality.

PSO, DEQ, and other Oklahoma's leaders should be commended for developing an Oklahoma strategy of our own, one that benefits our state by meeting federal environmental regulation while utilizing our own natural resources. This benefits all Oklahomans and our economy in the immediate and long term. Chesapeake fully supports the adoption of the Amended Regional Haze Agreement. Thank you.

MS. BOTCHLET-SMITH: Rick Chamberlain.

MR. CHAMBERLAIN: Good afternoon. I'm Rick Chamberlain. I'm representing Calpine Corporation today. As many of you know Calpine Corporation is an independent power producer of an 1100 megawatt privately owned natural gas

generating plant here in Oklahoma located near Tulsa. As part of its implementation of its Regional Haze Settlement that is evolving in the revised SIP, PSO conducted a competitive bid -- bidding process. It was overseen and monitored by an independent evaluator and as part of that process a purchase power agreement was entered into with Calpine Corporation. And under that, EPA, Calpine will provide 260 megawatts of natural gas fired capacity beginning in 2016 to replace some of the coal generation capacity that is being curtailed pursuant in the settlement. Calpine supports the PSO settlement; Calpine also supports the revised SIP being considered today. Thank you.

MS. BOTCHLET-SMITH: A.J. Ferate.

MR. FERATE: Thank you very much. I'm A. J. Ferate with Devon Energy, and here to speak in support

of the settlement for the State Implementation Plan. Devon Energy has been involved in and attempted to assist in an effort to encourage this for at least three years now.

Devon is a strong supporter of state primacy in all issues wherever it's possible. And in particular in this issue because we believe that it benefits the state to have State Implementation with people that understand the needs of the state compared to a federal representative trying to oversee this and possibly other things as it continues on.

Further, Devon is, of course, a producer of natural gas but believes natural gas is a clean alternative to some of the sources that are currently in use. And in fact, the International Energy Agency has cited the use of natural gas as the reason carbon emissions have continued to fall.

For today's comments we have

letter that we submitted to the Governor of Oklahoma in support of this from September of last and we supply that now.

Thank you.

MS. BOTCHLET-SMITH: Mr. Brandy Wreath.

MR. WREATH: Good afternoon. I am Brandy Wreath and I am the Director of the Public Utilities Division at the Oklahoma Corporation Commission and I am going to make it clear that I am here today making comments on behalf of the Public Utilities Division, not on behalf of our Oklahoma Corporation Commissioners. We are separate in that capacity.

I wanted to start off by saying today that I stand here in a different place than most of the people that came up here and spoke. I'm not here for the settlement; I'm not here against the settlement. I'm here today requesting DEQ to take a little bit more time before making a final decision in this settlement before making their final recommendations to the EPA. And I make that request today based on the concept that all of the relevant information that we've heard today, people have said that all the relevant information needs to be considered. And it's our belief that there is relevant information that has recently changed or come to our attention that's changed. And we believe everybody needs the opportunity to review all that information to make sure that today we're looking at the lowest reasonable cost for the Oklahoma ratepayer.

So, again, to us this isn't about coal or natural gas. My comments are totally segregated from that. Our comments are about the final decision that we come to is it considering all relevant facts. And

we believe the facts that are on the table today there are additional ones that need to be looked at. It may have the same outcome that this settlement is still the relevant best choice but there may also be changes that warrant minor modifications or possibly major changes. And unfortunately, no one can stand here today and say they know the outcome of that review because that has not been performed.

So I believe that that's a very important thing that needs to be done. There are relevant factors as you heard mentioned a little bit ago. There was a purchase power agreement to come out of the settlement and now we understand there's additional need for purchase power or additional generation possibly.

So those are major factors that we think need to be looked at. We're not asking for a permanent stop to this. We're not asking for it to

be withdrawn. We're asking everyone to just slow up a little bit, give us a little bit of time. There is a process that's about to begin before the Corporation Commission to allow them the opportunity to review the integrated resource plan updates of the Public Service Company of Oklahoma. In that review we will have the opportunity to look at what has changed since the time of the settlement. Our expert that we have put onboard to review the EPA/DEQ settlement, they will have the opportunity to review the changed information to see if it warrants any recommended adjustments and recommendations can be made at that time.

So I will say here at the end that the comments you've heard before, that the Oklahoma Corporation Commission will have to make the determination of reasonableness. What that means is they have to make

the choice at the end of the day if the cost of the settlement are passed through to the ratepayers. I believe that if we move forward at today's pace that it will be unfair for them to be asked to make a ruling without having all the pertinent and known facts in front of them. I think a little bit of time would allow them more comfort to review that. I know that for my staff that has to make recommendations to the Commissioners, we would request that time. We would just simply ask for the innovative resource process to run its normal course and then at that time everybody can review if anything major has changed and make final recommendations.

So thank you again for your time and we appreciate this meeting today.

MS. BOTCHLET-SMITH: Thank you. Do you have any written comments for today?

MR. WREATH: No.

MS. BOTCHLET-SMITH: Mr. Jeremy Jewell.

MR. JEWELL: Hello. My name is Jeremy Jewell. I am a Principal with Trinity Consultants, a worldwide environmental consulting firm, and I manage Trinity's operations here in Oklahoma.

I was responsible for completing, or overseeing the completion of, the technical analyses that went into PSO's BART reevaluation. It was these analyses that, after review and approval by the ODEQ, led to the proposed SIP revision that presents a BART determination involving the shutdown of one unit, the installation of Dry Sorbent Injection, or DSI, on the second unit, and the incremental decrease in capacity utilization leading to the ultimate shutdown of the second unit.

I would like to briefly address

our execution of and results of the two analyses that led to the proposed BART determination:

First, estimating the costs of the emissions control; and, second, the atmospheric modeling of both pre-control and post-control emission scenarios to determine visibility impacts in the nearby Class I areas, which are the Wichita Mountains National Wildlife Refuge in south-west Oklahoma, the Caney Creek Wilderness Area in south-get Arkansas, the Upper Buffalo Wilderness Area in north-central Arkansas, and the Hercules Glades Wilderness Area in south-central Missouri.

First, in regards to the modeling analyses, I want to point out four facts.

The modeling methods we used to evaluate the revised BART determination were largely the same as those relied upon in the original

BART determination. For example, the same CALPUFF processor was used. CALPUFF is the dispersion model used in the multi-step process of conducting visibility modeling. Also, the same meteorological dataset was used. To the extent possible, everything related to the modeling analyses was kept consistent with the previously reviewed and approved analyses.

The primary change from the original modeling methods to the updated modeling methods involved the use of what's called the CALPOST processor. CALPOST is the processor that converts the output of CALPUFF into visibility values which is what we use for BART determination. Since the original BART determination EPA developed and now requires the use of a newer version of CALPOST. This newer, EPA-required version was used in the BART reevaluation.

Additionally, we used the latest EPA

and Federal Land Manager guidance in regards to both the CALPOST algorithm or method and the background concentrations for parameters such as humidity that are fed into CALPOST.

The details of all the modeling methods, all the inputs, including the base-line and post control emission rates that were used, and all of the outputs of the model, all of which were based on the latest EPA regulation or guidance, were provided to ODEQ in a protocol for their review on or about September 25, 2012.

EPA's stated threshold for attributing visibility impairment to any single source of emissions is 0.5 delta-deciviews on a daily average 98 percentile basis. The results of the updated modeling show that predicted post-control visibility impacts are less than this threshold for all Class I areas of concern.

In regards to the cost of

controls estimates, I will mention three facts.

The original BART determination and SIP were based on costs developed by PSO's project engineers. In the Technical Support Document published with the EPA's disapproval of the original SIP, EPA presented an alternative cost analysis based largely on its own Cost Control Manual, a guidance document EPA most recently published in January of 2002.

In the BART reevaluation, for all cost effectiveness calculations, we strictly used EPA's Control Cost Manual in the same way that it was used by EPA in their own Technical Support Document. We also presented PSO's engineering cost estimates for comparative purposes. The results of the control cost evaluations regardless of which method was employed show that the scenario presented in the proposed SIP

revision is the most cost effective scenario that also achieves the necessary visibility improvement goal mentioned previously.

Thank you for your consideration of these comments.

MS. BOTCHLET-SMITH: Ms. Whitney Pearson.

MS. PEARSON: Whitney Pearson on behalf of the Sierra Club today.

The Sierra Club believes that the revised SIP fully complies with federal requirements (inaudible) regional haze and interstate pollution from the Northeastern coal plants. Implementation of this SIP will drastically reduce both SO2 and NOx emissions by 2016 and fully implement by 2026. Particulate matter emissions which also contribute to haze and public health problems will also see a drastic reduction. Clearing the haze of these parks will go to protect the

health of those who recreate there and promote local tourism by decreasing the number of days when pollution impairs scenic views.

In 2011, over 118,000 people visited the Wichita Mountains for enjoyment and recreation. Compared to the FIP, the SIP revision provides more flexibility for PSO to comply with its obligations under the Clean Air Act's Haze Provisions but it does not compromise public health or visibility.

The FIP scenario may have some lower impact for several years but the SIP revision better achieves the overall goals of the Regional Haze Program because emissions from both units will be completely eliminated by 2026.

The SIP revision not only permits PSO to avoid the high cost of installing operating scrubbers by providing for the retirement of the unit -- of the unit in 2016 but also

assures that PSO will avoid costs of upcoming regulations that would require the unit to internalize the costs of its air, water, and coal ash pollution and other harm to the environment.

It is a more cost effective solution that requires the installation of expensive scrubbers on both units. For these reasons and more the Sierra Club urges the DEQ to promptly approve and finalize the SIP. And our full written comments are available or have been submitted to Ms. Bradley.

MS. BOTCHLET-SMITH: Thank you. I need to take just a moment to check the front tables and see if there are any other requests for comments that have been submitted. Please bear with me for just a moment. Okay. I don't have any indication there are others that have indicated that they want to comment.

Are there any in the audience

that have decided that they want to speak but -- Eddie, do you want to say anything?

MR. TERRILL: No. I'm good.

MS. BOTCHLET-SMITH: Okay. I couldn't tell if you were raising your hand. Okay.

We advertised the meeting to go to 3:00 so we will leave the hearing record open until that time, should someone arrive or change their mind and decide that they wish to speak. You all are welcome to stay or if you have somewhere else to be that's fine too. But we -- DEQ will be here to receive comments until 3:00.

(Pause)

MS. BOTCHLET-SMITH: Jody Harlan.

MS. HARLAN: The Governor, Office of the Attorney General, Secretary of the Environment, Secretary of Energy, Corporation Commission staff and Oklahoma Sierra

Club support American Electric Power/Public Service Company's compliance plan as a common sense approach for complying with federal regulatory safeguards and setting firm dates for retirement of both AEP-PSO coal units.

I support the proposed revision of the Best Available Retrofit Technology, BART, for the AEP-PSO Northeastern Units 3 and 4, which provide for the first coal-burning unit to be phased out by April 16, 2016. The second unit will remain in use with pollution control technology installed by April 16, 2016. Between 2021 and 2026, AEP-PSO will significantly reduce the amount of coal burned at the unit until the plant is decommissioned no later than December 31, 2026. This option is more cost effective than retrofitting coal units with expensive scrubbers. Continuing to run the outdated, aging plants until 2041 would raise rates

for residential customers by 14.3 compared to a projected 11 percent under PSO's cost-effective plan.

Dangerous sulphur dioxide emissions from the Northeastern power plant near Oologah will be reduced by more than half in 2016 and fully eliminated by 2026.

Oklahomans' health will benefit from cumulative reductions in carbon dioxide, the primary cause of climate disruption, and sulfur dioxide, mercury, nitrogen oxides and other toxins. To address the visibility impairment at the Wichita Mountains Class I area, under the First Amended Regional Haze Agreement, AEP-PSO will develop a monitoring program to test operating profiles to determine if sulphur dioxide can be successfully removed during normal operations. In the event this is not achieved, I am relieved to read that sulphur dioxide emissions reductions will be obtained through enforceable emission limits

or control equipment requirements if necessary to realize the visibility benefits estimated in regional haze modeling.

Coal-fired energy generation is poisoning our water and air, wrecking our health and shortening lives in Oklahoma. The proposed SIP revision for the AEP-PSO Northeastern Units 3 and 4 avoids the risks of expensive investments in outdated technology. It allows AEP-PSO flexibility in transitioning to cleaner energy sources over a reasonable period of time. And it enables Oklahoma to comply with federal regulatory safeguards while ensuring a that we will have cleaner energy future.

(Pause)

MS. BOTCHLET-SMITH: This is Beverly Botchlet-Smith. It is now 3:00 and we have not had any others that want to comment so this concludes are Regional Haze hearing.

(Proceedings concluded)

C E R T I F I C A T E

STATE OF OKLAHOMA)
) ss:
COUNTY OF OKLAHOMA)

I, CHRISTY A. MYERS, Certified Shorthand Reporter in and for the State of Oklahoma, do hereby certify that the above proceeding is the truth, the whole truth, and nothing but the truth; that the foregoing proceeding was taken down in shorthand and thereafter transcribed by me; that said proceeding was taken on the 20th day of May, 2013, at Oklahoma City, Oklahoma; and that I am neither attorney for, nor relative of any of said parties, nor otherwise interested in said action.

IN WITNESS WHEREOF, I have hereunto set my hand and official seal on this, the 22nd day of May, 2013.

Christy Myers
CHRISTY A. MYERS, CSR
Certificate No. 00310

Keyword Index

Keyword Index

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Keyword Index

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

Regional Haze SIP Hearing

Monday, May 20, 2013
1:00 PM-3:00 PM

DEQ Multipurpose Room

NAME	AFFILIATION	CONTACT INFO
ALAN DECKER	PSO	awdeker@aep.com
JEREMY JEWELL	TRINITY CONSULTANTS	jjewell@trinityconsultants.com
Janet Henry	PSO	jjhenry@aep.com
MARK BARTON	PSO	PMBARTON@AEP.COM
Nancy Marshment	DEQ-AQD	ext 4172
Skyla McElhoney	DEQ	ext 7167
Lydia Pettitsas	OSN	mail4lydia@cox.net
Leon W. Paden	QOSC	LPADEN@IONET.NET
Tom Schroedter	OIEC	tschroedter@hallestill.com
Ed Schroedter	OIEC	
Brenda Barwick	CCO	jonesapr@gmail.com
John Tidwell	CCO	jmtulsa@gmail.com
PAUL MONIES	THE OKLAHOMAN	pmonies@opubco.com
Brooks Kirlin	DEQ-AQD	ext 4174
Bob Rounsavell	CITIZEN	918 640-4497
Jason Harpol	PSO	918 599 2400
Jerry Johnson	self	405-626-1912
Joe Liebrecht	Sierra Club	405-364-5759
NICOLE KING	OAG	nicole.king@oag.ok.gov
LEE WARDEN	ODEQ	
KIMBER SHOOP	OGE	ShoopKL@oge.com
SUSAN Schmidt	Sierra club	405 947-2061
DON Shandy	RWCS	405 228-2438

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

Regional Haze SIP Hearing

Monday, May 20, 2013
1:00 PM-3:00 PM

DEQ Multipurpose Room

NAME	AFFILIATION	CONTACT INFO
Bud Ground	PSO	hlground@aep.com
John Dirickson	CITY OF Oologah	" " " "
Cheryl Bradley	DEQ AQD	
Beverly Botchlet-Smith	DEQ	
Teryl L. Williams	Okla Corp. Comm'n	t.williams@occemail.com
MARK GARRETT	OIEC	mgarrett@garrettgroupllc.com
Muntelle Clark	OSN	montelle@cox.net
Scott Thomas	DEQ	scott.thomas@deq.ok.gov
Whitney Pearson	Sierra Club	whitney.pearson@sierraclub.org
Maria [illegible]	Carrie Dickerson Fdn	
David Ocamb	Sierra Club	david.ocamb@sierraclub.org
DURANT LEUNG	SIERRA CLUB	durant.unt@gmail.com
Kenneth Vincent	Sierra Club	
David [illegible]	OGE	
Jon Laasch	Dogwood Energy	jonlaasch@yahoo.com
John Huryn	BFW	
Bob Vandewater	OK Corp. Comm.	b.vandewater@occemail.com
Bill Humes	Okla Attorney General	bill.humes@oag.ok.gov
Jerry Sanger	" "	jerry.sanger@oag.ok.gov
Nancy Graham	INCOG	nlgraham@incog.org
Joann Stevenson	PSO	jtstevenson@aep.com
Rick Chamberlain	Calpine	rdc_law@swbell.net
Joel Rodriguez	OCC	j.Rodriguez@occemail.com

O K L A H O M A
DEPARTMENT OF ENVIRONMENTAL QUALITY

Regional Haze SIP Hearing

Monday, May 20, 2013
1:00 PM-3:00 PM

DEQ Multipurpose Room

NAME	AFFILIATION	CONTACT INFO
Emily Shuart	PSO	ecshuart@aep.com
Tiffany Lyda Kelley	PSO	TSLyda@AEP.COM
Jack R. Fite	PSO	Jfite@wcgflaw.com
A.J. FERATE	DEVON	AJ.FERATE@DVN.com
A. TAYLOR	OCC	a.taylor@occemail.com
C. Herron	OGE	herronlk@oge.com
B. Wreath	OCC	b.wreath@occemail.com
Maressa Treat	SOE	maressa.treat@doe.ok.gov
Jim Roth	CHK	jimroth405@gmail.com
Jeff Riles	Phillips Murrah	jmriles@phillipsmurrah.com
Matt Ball	AFP	mball@afphq.org
David Williamson	AFP	dwilliamson@afphq.org
Gerald Butcher	WFEC	g_butcher@wfec.com
Julia Bevers	OGE	beversjo@oge.com
Sarah Lilly	Sierra Club	sarahjanelilly@yahoo.com

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

Regional Haze SIP Hearing

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1:00 PM-3:00 PM

DEQ Multipurpose Room

NAME	AFFILIATION	CONTACT INFO
Ford Benham	OGE	553-3221 benhamfk@oge.com
U. Turner		553 · 3633.
JENNIFER BOYLE	DEQ (AQD)	702-7158
Stephen Baldridge	DEQ	702-7188
STAN WHITEFORD	PSO	918 599-2574
Melody Martin	OGE	553-3297
Martha Penisten	DEQ	702 7184
Deborah Thompson	Atty	8445-3707
Jamie Maddy	CHK	405-935-3607
Judith L. Johnson	OCC/OGC	(405)5220484

O K L A H O M A
DEPARTMENT OF ENVIRONMENTAL QUALITY

PROPOSED REVISION FOR
REGIONAL HAZE STATE IMPLEMENTATION PLAN
AND
INTERSTATE TRANSPORT SIP

MAY 20, 2013

*** PLEASE COMPLETE THIS FORM IF YOU WISH TO COMMENT ***

NAME John Dirickson

AFFILIATION City of Oologah

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OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY

PROPOSED REVISION FOR
REGIONAL HAZE STATE IMPLEMENTATION PLAN
AND
INTERSTATE TRANSPORT SIP

MAY 20, 2013

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NAME Tom Schroedter

AFFILIATION Oklahoma Industrial Energy Consumers

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REGIONAL HAZE STATE IMPLEMENTATION PLAN
AND
INTERSTATE TRANSPORT SIP

MAY 20, 2013

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NAME Bud Ground

AFFILIATION PSO

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OKLAHOMA
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PROPOSED REVISION FOR REGIONAL HAZE STATE IMPLEMENTATION PLAN AND INTERSTATE TRANSPORT SIP

MAY 20, 2013

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NAME BoB Rounsavell

AFFILIATION Connie Dickerson Foundation

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REGIONAL HAZE STATE IMPLEMENTATION PLAN
AND
INTERSTATE TRANSPORT SIP

MAY 20, 2013

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NAME Jon W. Laasch

AFFILIATION Dogwood Energy LLC

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MAY 20, 2013

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NAME LEE PADEN

AFFILIATION QUALITY of SERVICE COALITION

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INTERSTATE TRANSPORT SIP

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NAME Susan Schmidt

AFFILIATION Sierra Club

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PROPOSED REVISION FOR
REGIONAL HAZE STATE IMPLEMENTATION PLAN
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MAY 20, 2013

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NAME Jamie Maddy

AFFILIATION Chesapeake

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REGIONAL HAZE STATE IMPLEMENTATION PLAN
AND
INTERSTATE TRANSPORT SIP

MAY 20, 2013

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NAME Rick Chamberlain

AFFILIATION Calpine Corporation

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PROPOSED REVISION FOR REGIONAL HAZE STATE IMPLEMENTATION PLAN AND INTERSTATE TRANSPORT SIP

MAY 20, 2013

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NAME A. J. Ferate

AFFILIATION Devon Energy

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PROPOSED REVISION FOR REGIONAL HAZE STATE IMPLEMENTATION PLAN AND INTERSTATE TRANSPORT SIP

MAY 20, 2013

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NAME Brandy Wreath

AFFILIATION Ok. Corporation Commission- Public Utility Division

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Requested to be last

OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY

PROPOSED REVISION FOR REGIONAL HAZE STATE IMPLEMENTATION PLAN AND INTERSTATE TRANSPORT SIP

MAY 20, 2013

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NAME JEREMY JEWELL

AFFILIATION TRINITY CONSULTANTS

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OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY

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MAY 20, 2013

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NAME Whitney Pearson

AFFILIATION Sierra Club

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Appendix VII

Summary of Comments and Responses – FLM and Public Comments

SUMMARY OF COMMENTS AND STAFF RESPONSES
FOR PROPOSED REVISION TO
THE STATE IMPLEMENTATION PLAN
FOR REGIONAL HAZE AND TRANSPORT

COMMENTS RECEIVED PRIOR TO AND AT THE
MAY 20, 2013 PUBLIC HEARING

Comments from Federal Land Managers (FLMs)

U. S. Fish and Wildlife Service (FWS) - Letter dated April 15, 2013 from Sandra V. Silva, Chief, Branch of Air Quality

1. **COMMENT:** "Reference to the relevant authority within the U.S. Environmental Protection Agency (EPA) regulation that provide for this BART action should be included in the Proposed BART documentation." The comment goes on to cite 40 CFR Part 51, Appendix Y guidance on averaging emissions across any set of BART-eligible units within a fence line, referring to the reliance in the BART determination on contemporaneous emission reductions in the cost effectiveness and visibility improvement analyses. In a footnote to the comment, the FWS expressed concern that the final BART emission rate would be greater than presumptive control levels identified in Appendix Y.

   RESPONSE: The Best Available Retrofit Technology (BART) determination was made through a top-down analysis of control technologies, considering the statutory factors and the presumptive control levels identified in Appendix Y. EPA has stated that "[t]he BART Rule has presumptive limits that act as a starting point for the establishment of BART emission limits unless the state's analysis indicates that an emission limit more or less stringent than the presumptive limit is required." (*Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze*, 77 Fed.Reg. 14604, 14611 (Mar. 12, 2012).

   In order for the facility to achieve compliance with an emission rate of 0.15 lbs/MMBtu (the presumptive limit), the coal-fired boilers would need to install Dry Flue Gas Desulfurization (DFGD), as shown in previous analyses in support of the original State Implementation Plan and the Federal Implementation Plan (FIP). The analyses documented in the Revised BART Determination (Appendix II-1) conclude that, given the comparable visibility improvement, significantly lower costs, and overall reduced environmental impact, the proposed control (low sulfur coal and Dry Sorbent Injection or DSI) constitutes BART. This determination relies upon an enhanced effectiveness provided through contemporaneous emission reductions from the multi-media, multi-pollutant strategy outlined in the Supplemental BART Determination Information (Appendix II-2). Through incorporation in the First Amended Regional Haze Agreement (Appendix III-1), this strategy was made enforceable and therefore, eligible for reliance upon in the BART analysis.

Relying on the emission reductions inherent in the First Amended Regional Haze Agreement is appropriate in the BART review. There are no provisions in the Regional Haze Rule or guidelines suggesting that States are barred from considering the reduction of emissions attributable to the contemporaneous shutdown of a BART-subject unit in the BART determination for any remaining BART-subject units "within the same fence line." Instead, in the BART Guidelines,[1] EPA urges States to allow BART subject units "within the same fence line" to average emissions in demonstrating compliance with BART requirements. Although there are no regulatory citations specifically allowing for a contemporaneous retirement to be relied upon in a BART determination, it was clearly contemplated that reductions for one unit could be averaged with reductions at another unit to comply with BART. The BART emission rate of 0.4 lb/MMBtu has been shown to be more cost-effective on a mass basis, as well as a reduction in visibility impairment basis, than the FIP-established 0.06 lb/MMBtu. As was stated previously, the FIP and presumptive limits at a minimum presume installation of DFGD. Therefore, since the proposed BART is found to be more cost-effective for emission reductions and visibility improvement than the FIP, it is necessarily more cost-effective than the presumptive control, which would assume no retirement.

2. **COMMENT:** "On Page 6 of the Revised BART Determination it states that all cost analyses were based on an 85% capacity factor. Appendix Y states, 'When you project that future operating parameters (e.g., limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) will differ from past practice, and if the projection has a deciding effect on the BART determination, then you must make these parameters or assumptions into enforceable limitations. In the absence of enforceable limitations, you calculate baseline emissions based upon continuation of past practice.'" (Section IV.D. STEP 4.d.2) "This would indicate that an 85% capacity limitation should be placed in the permits of the units operating under the proposed BART."

   RESPONSE: The 85% capacity factor was identified in the original BART determination and reflected the past actual operation of the facility as documented in annual emission inventories. The rate was relied upon in the FIP and again in the proposed SIP revision. Consistent with the guidance, in the absence of enforceable limitations, DEQ calculated emissions based upon the continuation of past practice. Note that the reduced utilization factors beginning in 2021 for the remaining unit are specified in the Regional Haze Agreement (Feb. 10, 2010), as amended by the First Amended Regional Haze Agreement (Mar. 26, 2013), and will be incorporated into the facility's air quality permits. These enforceable capacity restrictions are not relied upon in the BART determination, as they are beyond the BART compliance deadline.

3. **COMMENT:** "All of the permits or other enforceable commitments should be posted as an appendix to the BART section of the Regional Haze State Implementation Plan (SIP). This should include emission limitations of zero on the unit that will be closed."

---

[1] *See* 40 CFR Part 51, Appendix Y, Section V (Enforceable Limits/Compliance Date).

RESPONSE: The Regional Haze Agreement as amended by the First Amended Regional Haze Agreement is the enforceable document relied upon for the revised BART determination. The Agreement was included in the appendices. All relevant requirements will be incorporated into the facility's air quality permit, including retirement of the units as proposed. The inclusion of an emission limit of zero is unnecessary.

4. **COMMENT:** In "[t]he fourth paragraph of Page 11 of the Revised BART Determination [i]t is incorrect to dismiss a control strategy [of Dry Flue Gas Desulfurization/Spray Dryer Absorber (DFGD/SDA)] on the basis that the resulting improvement is not perceptible or significant." "The erroneous imperceptibility discussion should be removed since the last sentence of the paragraph correctly provides a cost per deciview improvement analysis for each control alternative." (FWS quotes the preamble to EPA's BART Guidelines which states, "[e]ven though the visibility improvement from an individual source may not be perceptible, it should still be considered in setting BART because the contributions to haze may be significant relative to other source contributions in the Class I areas.")

RESPONSE: DEQ defined the thresholds for causing or contributing to visibility impairment in OAC 252:100-8-73(a)(1) and (2). "A source that is responsible for an impact of 1.0 deciview or more is considered to cause visibility impairment. [ ] A source that causes an impact greater than 0.5 deciviews contributes to visibility impairment." These thresholds are consistent with EPA guidance. Under the SIP revision, the three year average of the 98th percentile maximum impairment, for three of the four Class I areas impacted is less than the threshold to be considered a contributor to visibility impairment. The three year average for the Caney Creek Class I area remains above 0.5 deciview (dv) at 0.55 dv. The average difference between the remaining impairment under the FIP and the revised SIP is 0.18 dv. Although 1 dv is commonly held as the threshold for perceptibility to the human eye, referring to the difference as trivial (instead of imperceptible) is more accurate and the language has been modified.

5. **COMMENT:** The FWS states that the cost per deciview of visibility improvement and cost per ton of SO_2 control that is stated for *each* control alternative is consistent with the other states' determinations of reasonable costs. "[C]osts related to non-air quality environmental impacts are a relevant factor to consider as pointed out in the ODEQ analysis. The point that both cost per ton and cost per deciview are reasonable for *each* control alternative is brought up only to confirm the DFGD/SDA alternative should not have been dismissed on the basis of excessive cost under BART but because DSI was chosen on the basis of lower cost. Either control alternative seemed to meet the constraints of the five-factor BART analysis."

RESPONSE: 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 substantially more cost effective revised BART determination of $5,690,172 per dv. The revised BART determination is justified given that a comparable improvement in visibility is achieved at a much lower cost.

U.S. Forest Service (FS) - Letter received May 20, 2013 from Judith Henry, Forest Supervisor and Norman L. Wagoner, Forest Supervisor.

6. **COMMENT:** "As proposed by ODEQ, the SO_2 emission rates for Units 3 and 4 will each be lowered from the present 0.9 lb/mmBTU, utilizing dry sorbent injection (DSI) to 0.65 lb/mmBTU by January 21, 2014, and then to 0.60 lb/mmBTU by December 21, 2014. And by April 26 2016, the SO2 emission rated for Unit 3 is proposed for further reduction to 0.4 lb/mmBTU (Table II-2), while Unit 4 will be shut down. While these proposed reductions would a be clear improvement from present levels, all are considerably less stringent than EPA's and the Forest Service's preferred BART level of 0.06 lb/mmBTU, utilizing DFGD/SDA."

   RESPONSE: Dry Flue Gas Desulfurization is a more stringent control technology than DSI. It is also a much more costly control option. The BART review considered the reductions in emissions from the baseline for both units. Reliance upon the emission reductions inherent in the Supplemental BART Determination Information (Appendix II-2) is appropriate in the BART review. See Response to Comment Nos. 1 and 5. The resultant cost effectiveness calculation demonstrates that the SIP proposal is more cost effective than the FIP.

7. **COMMENT:** "It appears ODEQ rejects the use of DFGD/SDA asserting on page 11 of the revised BART determination that the incremental reductions in emissions will not result in perceptible improvement in visibility. The perceptibility of improvement should not be a factor in determining BART. Based on the preamble to EPA's BART Guidelines: 'Even though the visibility improvement from an individual source may not be perceptible, it should still be considered in setting BART because the contributions to haze may be significant relative to other source contributions in the Class I areas.'"

   RESPONSE: See Response to Comment No. 4.

8. **COMMENT:** "It is also noted that the cost per deciview of visibility improvement that is stated for each control alternative is consistent with other states' determinations of reasonable cost per deciview, and the $1,544 cost per ton of SO_2 control is reasonable when compared with options utilized across the country. Further, while the cost per ton for DSI is 65% of the more cost effective DFGD/SDA option, the utilization of DFGD/SDA is well over six times more efficient at removing SO_2. (See Table 8 in ODEQ's March 20, 2013 Revised BART Determination)."

   RESPONSE: It is well established in the revised BART determination that the requirements set forth in the proposed SIP revision are more cost effective than the DFGD/SDA option. Focusing on emission factors alone neglects to consider the contemporaneous emission reductions resulting from the shut-down of one of the boilers. Therefore, despite the difference in emission factors, the revised BART determination in the proposed SIP revision provides nearly equivalent reductions in visibility impairment for the Class I areas at much less cost. From a further reasonable progress perspective, the long-term significance of the enforceable lifespans for the two boilers is that it provides much greater benefit to the Class I areas than the short-term benefits from a strict adherence to a more stringent emission factor.

Other Written Comments

Letter from the Honorable Scott Pruitt, Attorney General of the State of Oklahoma, received on May 20, 2013:

9. **COMMENT:** "A review of DEQ's Revised BART Determination reveals a fundamental omission – while DEQ considered the cost of emissions control equipment over the life of the operating coal unit, it did not consider the cost of replacement capacity/energy for both units that is, of necessity, part of the plan." The Attorney General's comment goes on to specify that the revised BART determination should have considered the replacement cost associated with additional purchased-power and the additional costs that arise between the use of coal and the use of natural gas as a fuel source. In addition, the Attorney General's comments state that PSO intends to submit an amended Integrated Resource Plant ("IRP") to the Oklahoma Corporation Commission and that "[t]he stated purpose for the amendment is PSO's updated need to serve approximately 250 MWs of load in the 2016 timeframe." In regard to this issue, the comment concludes, "DEQ's cost effectiveness determination is based on incomplete information and clearly underestimates the true costs of the proposal, and by extension, the cost effectiveness of the revised SIP."

RESPONSE: In regard to comments related to consideration of replacement costs, please refer to Response to Comment No. 28. In regard to comment related to consideration of information in an IRP, please refer to Response to Comment No. 11.

10. **COMMENT:** The Attorney General's comments state that, arguably, the proposed SIP revision is more stringent than the FIP and, as a result, the revised SIP should have included an Economic Impact and Environmental Benefit Statement pursuant to 27A O.S. § 1-1-206.

RESPONSE: The requirements related to an Economic Impact and Environmental Benefit Statement ("EI/EBS") under 27A O.S. § 1-1-206 apply to permanent rulemakings. Since the proposed SIP revision does not include a permanent rulemaking, these provisions do not apply. The permanent DEQ rules specifically related to the Regional Haze SIP may be found at OAC 252:100-8-70 through -78. These permanent rules were promulgated in 2007 and were approved with the portion of the Oklahoma Regional Haze SIP approved by EPA in December 2011. These permanent rules were determined to not be more stringent than the corresponding Federal rules and, consequently, no EI/EBS was prepared for those permanent rules. In any event, DEQ believes that the proposed SIP revision is not more stringent than the FIP.

Letter from the Honorable Scott Pruitt, Attorney General of the State of Oklahoma, received on May 15, 2013:

11. **COMMENT:** This comment also states that the DEQ's Revised BART Determination should have considered replacement costs and is incomplete because of the possibility of an amended 2012 IRP. The comment also includes the statement that an EI/EBS should have been included with the proposed SIP revision. The letter concludes with a request that the public hearing scheduled for May 20, 2013, be delayed until PSO's amended IRP could be vetted in proceedings at the Oklahoma Corporation Commission.

RESPONSE: In regard to the portion of the comment related to consideration of capacity and energy replacement costs, please refer to Response to Comment No. 28. In regard to the portion of the comment related an EI/EBS, please refer to Response to Comment No. 10. As for the requested delay, the decision was made to proceed with the public hearing as scheduled. The purpose of the hearing was to solicit public comment, and to provide an opportunity for any new information (including relevant information related to the cost effectiveness analysis) to be submitted and considered in the final decision making process. Also, in the settlement agreement referred to in the comments, the Oklahoma Secretary of Environment agreed to submit a final proposed SIP revision to EPA for review and approval by June 18, 2013. Any unnecessary delay of the scheduled hearing would prevent that deadline from being met. In addition, the potential new information described in the request does not appear to be directly related to the type of information permitted to be considered in developing a Regional Haze SIP (*see* Response to Comment No. 28 for further detail); instead, the described information appears to be more directly related to proceedings before the Oklahoma Corporation Commission. Since the Oklahoma Corporation Commission has stayed the proceedings related to the costs associated with these environmental compliance measures until EPA makes a final decision on the proposed SIP revision, avoiding unnecessary delay in the SIP development process would likely result in the information being considered by the appropriate agency and in the appropriate forum in a more expeditious manner. (*See* Response to Comment No. 28 for further detail).

American Electric Power - Letter received on May 17, 2013 from Janet J. Henry, Deputy General Counsel

PSO's comments addressed statements included in a recent request (letter to the DEQ Executive Director dated, May 15, 2013) by Attorney General Pruitt's office to delay the hearing scheduled for Monday, May 20, 2013.

12. **COMMENT:** "That request urges ODEQ to re-evaluate the revised RH-SIP based on changes in PSO's load profile and cost of replacement power necessary to offset the retirement of one Northeastern coal-fired unit in 2016. However, the BART analysis ODEQ is required to undertake is a narrowly focused analysis that looks only at the relative cost of environmental controls on the BART-eligible units, and ODEQ's selection of the alternative that represents the 'best available retrofit technology' for those units, as defined in the Clean Air Act. While ODEQ has the discretion to consider costs associated with the energy demands of control equipment, and other non-air environmental impacts associated with the operation of particular control devices in its analysis of the most cost-effective option to address the visibility concerns that are the focus of the regional haze program, ODEQ does not have the authority or the expertise to

evaluate replacement resources or the adequacy of PSO's full complement of resources to meet customer demand."

RESPONSE: DEQ concurs.

13. **COMMENT:** "PSO regularly evaluates and reports to the Oklahoma Corporation Commission on its resources plans, and, as noted in the letter, has announced its intention to submit a revised resource plan to the Commission in the near future. That revised resource plan will not provide any other relevant information to ODEQ that is necessary in order to complete its evaluation of the revised RH-SIP. Nothing in that plan will alter the relative costs of the various emission control options studied in the BART analysis submitted by PSO, or ODEQ's evaluation of the costs, energy impacts, and visibility improvements associated with the various alternatives studied. Accordingly, there is no reason to delay the public hearing or to defer any decision on the adequacy of the revised RH-SIP developed by ODEQ."

RESPONSE: DEQ concurs that it is appropriate to proceed with the public hearing and the proposed SIP revision submittal as scheduled (*see* Response to Comment No. 11 for further detail). In regard to the remaining portion of the comment, no response is necessary.

14. **COMMENT:** "The letter also claims that it is 'arguable' that the revised RH-SIP is more stringent than the previously issued EPA FIP. However, there is no evidence that the revised SIP would impose more stringent emission reduction requirements than the current FIP. The primary focus of the revised RH-SIP for Northeastern Unit 3 and Northeastern Unit 4 is the choice of BART controls for SO_2 emissions. Under the FIP, each Northeastern Unit would be required to meet a 0.06 #/mmBtu emission rate. EPA's basis for meeting this limit is the installation of high-efficiency dry scrubbers on both units by January 2017. Under the SIP, one Northeastern Unit will retire and the other will be equipped with a dry sorbent injection system that is capable of achieving a 0.4 #/mmBtu emission rate. This rate is clearly a compromise between the 0.65 #/mmBtu rate that was included in the prior RH-SIP and the rate approved in the FIP. As demonstrated in the Revised BART Determination (at page 11) the revised RH-SIP reduces SO_2 emissions by approximately 24,888 tons per year while the FIP would reduce emissions by approximately 29,119 tons per year. However, the cost per ton of SO_2 reduction under the RH-SIP is $1,005 per ton, while the cost per ton of SO_2 reductions under the FIP is $1,544 per ton. The incremental cost to achieve the additional 4,231 tons of reductions under the FIP is $4,718 per tons, and would not result in any perceptible improvement in visibility. As demonstrated in the Revised BART Determination, the revised RH-SIP is effective, but more moderate and cost-effective approach to visibility improvement than the currently approved FIP."

RESPONSE: DEQ concurs that the proposed SIP revision is not more stringent than the FIP.

15. **COMMENT:** PSO urged the ODEQ, after careful evaluation of the comments submitted during the public comment period, to promptly finalize the revised RH-SIP.

RESPONSE: DEQ acknowledges the comments in support of the propose SIP revision.

Carrie Dickerson Foundation/Sierra Club Prepared Hearing Statement – Written statement submitted at the public hearing by Mr. Bob Rounsavell, President of the Carrie Dickerson Foundation and Sierra Club member

16. **COMMENT:** "The agreement will bring about environmental benefits resulting in significant health benefits." "ODEQ should approve the PSO plan. It's cleaner, it will support Oklahoma jobs, and it will keep ratepayer money close to home." "This plan is a necessary start to improving air quality for the future."

    RESPONSE: DEQ acknowledges the comment in support of the proposed SIP revision.

Chesapeake Energy Corporation – Letter received via email from Jamie Maddy, Director - Regulatory

17. **COMMENT:** The comment states that the First Amended Regional Haze Agreement is BART-compliant and significantly and affordably addresses regional haze with substantial environmental benefits. Accepting this proposal for submission to EPA allows PSO to plan for compliance and address its needs as well as the needs of the ratepayers.

    RESPONSE: DEQ acknowledges the comment in support of the proposed SIP revision.

18. **COMMENT:** **"**The First Amended Regional Haze Agreement provides an Oklahoma-centered solution by leaning on Oklahoma resources to reduce power plant emissions and provide reliable electricity." "EPA has acknowledged that greater utilization of cleaner burning natural gas is a means for both PSO and OG&E to meet their BART obligations under federal law." "This First Amended Regional Haze Agreement will, in part, result in greater utilization of natural gas and consequently, will have a positive impact on Oklahoma's economy." "Oklahoma's Energy Plan calls for a strategy that increases reliance on Oklahoma resources for power generation which, according to the plan, helps preserve Oklahoma's relative low cost of energy and electricity while simultaneously strengthening the economy."

    RESPONSE: DEQ acknowledges the comment in support of the proposed SIP revision.

19. **COMMENT:** "Chesapeake supports the adoption of the First Amended Regional Haze Agreement."

    RESPONSE: DEQ acknowledges the comment in support of the proposed SIP revision.

Devon Energy Corporation – Letter dated May 20, 2013 from William F. Whitsitt, Ph.D., Executive Vice President, Public Affairs

20. **COMMENT:** "Devon Energy Corporation supports the settlement between Public Service Company of Oklahoma (PSO) and the U.S. Environmental Protection Agency (EPA) addressing the Revision to the Regional Haze State Implementation Plan. Devon requests that the Oklahoma Department of Environmental Quality approve the settlement."

"This settlement allows Oklahoma to retain state control and primacy over air regulation. It is also based on the benefits of natural gas, a clean fuel produced locally."

RESPONSE: DEQ acknowledges the comment in support of the proposed SIP revision.

Vaught & Conner, PLLC, on behalf of Dogwood Energy Corporation, LLC – Letter dated May 20, 2013 from Cheryl A. Vaught

21. **COMMENT:** "The SIP Revision is consistent with the State of Oklahoma's energy plan. The state energy plan prioritizes the increased use of Oklahoma's energy resources such as wind and natural gas, and protection of public health and the environment."

RESPONSE: No response is necessary.

22. **COMMENT:** "Transitioning from coal to gas, wind, energy efficiency, and demand response also has significant benefits for the overall reliability of the grid." "The switching [to natural gas] option would result in plants better suited to integrate with variable wind generation . . . ."

RESPONSE: DEQ acknowledges the information concerning the electricity generation industry provided by Dogwood.

23. **COMMENT:** "Dogwood supports the SIP Revision and urges DEQ to promptly move forward."

RESPONSE: DEQ acknowledges the comment in support of the proposed SIP revision.

INCOG – Letter dated May 17, 2013 from Nancy Graham, Air Quality Program Manager

24. **COMMENT:** "The proposed Regional Haze Revised State Implementation Plan (RH SIP) will dramatically reduce the facilities' short and long term emissions through the use of [BART]. Consequently, these SO_2 and NO_x reductions are expected to have a positive impact in reducing ground-level ozone and particulates in the Tulsa metropolitan area."

RESPONSE: DEQ concurs.

25. **COMMENT:** "This Revised RH SIP is the product of initiative, cooperation and common sense. The plan provides a reasonable approach to achieve lower emissions, to meet both RH guidelines and federal Mercury and Air Toxics Standard (MATS), and to provide for additional scheduled emissions reductions."

RESPONSE: DEQ acknowledges the comment in support of the proposed SIP revision.

Oklahoma Industrial Energy Consumers (OIEC) – Letter dated May 17, 2013 from Thomas P. Schroedter, Executive Director

26. **COMMENT:** "The underlying Agreement. The Proposal is based upon, and is intended to implement, a settlement agreement ("Agreement"). [Proposed] Regional Haze Implementation Plan Revision, p. 4 (Mar. 20, 2013). That Agreement was executed on behalf of the State of Oklahoma by Gary L. Sherrer, Secretary of the Environment for the State of Oklahoma (the "Secretary"). The Secretary has certain limited statutory duties, and such other duties as designated by the Governor. 27A O.S. §1-2-10l (2011). Binding the State by entering into settlement agreements is not a statutory power of the Secretary, nor could it be considered an implied power necessary to an efficient exercise of his limited express duties. *Strong* v. *Police Pension and Retirement Bd.,* 115 P. 3d 889, 893 (Okla. 2005). Accordingly, unless the Secretary has some written authority from the Governor authorizing him to enter into settlement agreements binding the State, which writing would have to have been issued prior to October 1, 2012, the date the Secretary executed the Agreement, the Agreement is an *ultra vires* act of the Secretary and hence void. See, *Canning* v. *NLRB,* 705 F. 3d 490,513-14 (CADC 2013). If the Agreement is void, DEQ should withdraw the Proposal, because it no longer has any basis."

RESPONSE: The proposed SIP revision is based on the Supplemental BART Determination Information submitted by PSO and the First Amended Regional Haze Agreement entered into by PSO and DEQ. The application appears to meet the relevant requirements and, therefore, DEQ prepared the proposed SIP revision, including the revised BART determination. The proposed SIP revision is not dependent on the existence of the settlement agreement referenced in this comment and the settlement agreement is not a necessary component of a SIP revision. The purpose of referencing the settlement agreement in the proposed SIP revision was only to provide nonessential background. To the extent the settlement agreement was referenced elsewhere in the draft proposed SIP revision, the reference should be to the First Amended Regional Haze Agreement included as Appendix III-1. DEQ believes that the required elements of a Regional Haze SIP revision are satisfied regardless of whether the settlement agreement is considered. In any event, on March 30, 2011, Governor Mary Fallin designated the Oklahoma Secretary of Environment, Gary Sherrer, as her designee for State Implementation purposes.

27. **COMMENT:** "Shut down cannot be BART. BART 'means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility.' 40 C.F.R. §51.301. Simply put, BART is defined to constitute the available retrofit technology which is expected to be most cost effective and most effective in reducing air emissions and improving visibility for certain existing stationary sources. EPA's BART Guidelines provide that BART cannot be conversion of an existing coal plant to natural gas (40 C.F.R. Part 51, Appendix Y, §IV(D)(3) and (5)), because conversion is not 'retrofitting.' See also, 76 Fed. Reg. 81750 (Dec. 28, 2011). For similar reasons, mandating the early retirement of a generating facility to achieve emissions reductions also cannot be BART. Not only would there be no 'retrofit'; there would cease to be 'an existing stationary facility.' Accordingly, the Proposal, which requires retirement of the Units years before the end of their useful operating lives, cannot be adopted as BART."

RESPONSE: BART is primarily an emission control program, but is not exclusively a retrofit technology program, given the requirement to review pollution prevention options in the BART guidelines. PSO developed a long-term multi-media, multi-pollutant targeted plan and proposed this for consideration in the revised BART determination. Nothing prohibits the State from considering the emissions reductions attributable to strategic business decisions in the evaluation of BART.[2]

The language in the SIP has been modified to state that the revised BART determination relies on the Supplemental BART Determination Information submitted by PSO and made enforceable in the First Amended Regional Haze Agreement. With this change, the SIP language has been modified to clearly reflect the distinction between the BART determination and the additional emission reductions from a unit retirement relied upon to come to that determination. The remaining efforts – decreasing capacity utilization and an additional unit retirement (from PSO's long-term multi-media, multi-pollutant plan) – were considered in the further reasonable progress assessment. However, the (revised) BART determination does not mandate unit retirements.

In the context of a BART review, the remaining useful life of the source is established by the company (PSO).[3] However, for the company to take credit for the emission reductions inherent in the shutdown of the unit, "this date should be assured by a federally- or State-enforceable restriction preventing further operation."[4] In order to afford PSO the opportunity to take credit for the emission reductions from the proposed shutdown, the date of the shutdown had to be included in an enforceable administrative order.

[2] Under 40 CFR Part 51, Appendix Y Section IV(D)(1) 3, EPA discusses the review of pollution prevention options with the caveat that ''it is not our intent to direct States to switch fuel forms, e.g. from coal to gas.'' [From the context of the comment, it appears that the commenter's intended reference was to §IV(D)(1) 3 and 5, rather than §IV(D)(3) and (5).] This is not a prohibition on considering a fuel switch proposed by a company. The fact that EPA cites this language in their response to comments (76 Fed.Reg. 81750 (Dec. 28, 2011) on why a fuel switch was not mandated in the FIP is understandable. It is reasonable that EPA not impose the requirement in the Oklahoma FIP where they have indicated no intent to require the States to do so.

[3] *See* 70 Fed.Reg. 39169 (July 6, 2005).

[4] ibid.

28. **COMMENT:** "Even assuming, *arguendo*, that mandating the early retirement of the Units could be considered as part of a BART proposal, it was error to not consider certain important 'costs of compliance' as required by applicable regulations. 40 C.F.R. §51.301 (definition of BART). These omitted compliance costs include: a) the cost of replacement capacity and energy arising from the mandated retirement of one of the Units in 2016; b) the cost of replacement energy arising from the capacity restrictions which are imposed on the second Unit during the period 2021-2026; and c) the cost of replacement capacity and energy arising from the mandated retirement of the second Unit no later than 2026."

RESPONSE: As discussed in the Response to Comment No. 27, DEQ did not mandate shutdown or capacity restrictions on either unit. PSO proposed the planned activities in their application submitted (consistent with the settlement agreement) as a revision to PSO′s previous submittal under OAC 252:100-8-76. DEQ entered into an administrative order with PSO to make the planned activities enforceable and therefore eligible to be relied upon in the BART review. It is DEQ′s responsibility to review the environmental impact and control technology selection of the project. In the BART guidelines,[5] EPA outlines the criteria to be considered in evaluating the costs of compliance. These costs and supporting methodologies, center on the control technology selection. There are no provisions providing for the evaluation of costs associated with voluntary measures, such as the unit retirements and capacity restrictions proposed by PSO. While it is appropriate to consider the visibility improvement resulting from these actions, it is inappropriate to consider the costs associated with any such replacement. Stated otherwise, the cost effectiveness review included in the BART determination is with respect to the cost of controls only and not the cost of a replacement unit or capacity. DEQ took into consideration the cost of compliance, and the energy and non-air quality environmental impacts of compliance. To the degree that utility rates may be impacted, the evaluation of costs associated with a replacement unit or capacity are under the jurisdiction of the Oklahoma Corporation Commission.

It should be noted that in testimony before the Oklahoma Corporation Commission, PSO discussed the decision to bring this proposal forward identifying known and anticipated future regulatory requirements for the facility. PSO proposed the retirement dates and capacity restrictions as the most effective way to address Regional Haze requirements and ensure compliance with the Mercury and Air Toxics Standards (MATS). PSO also took under consideration: the proposed Coal Combustion Residuals (CCR) Rule, which could require conversion of wet ash disposal systems to dry landfill systems, the possible relining or closing of ash ponds, as well as the possible construction of waste water treatment facilities; the proposed Clean Water Act "316(b)" rule, which establishes technology standards for the design and operation of cooling water intake structures at existing electric generating facilities; and future revised NAAQS for particulate matter and ozone. The comment, in focusing on cost effectiveness of SO_2 removal and visibility improvement attempts to place the burden of justification for PSO′s long term multi-media, multi-pollutant targeted approach solely on compliance

[5] *See* 40 CFR Part 51, Appendix Y.

with one environmental program and ignores the costs associated with compliance with these other regulatory requirements.

29. **COMMENT**: "Visibility/Greater Reasonable Progress Evaluation. It has not been demonstrated that the proposal meets the requirement that approvable alternatives to BART must achieve greater reasonable progress than would be achieved through the installation and operation of BART (i.e., the DFGD retrofit option). 40 C.F.R. § 51.308(e)(2)(i). In fact, on page 11 of the Revised BART Report, it is acknowledged that the DFGD option 'would provide improvements in visibility above that achieved with the DSI system' but argues that such improvements would not be perceptible. This conclusion clearly indicates that the Proposal does not meet the greater reasonable progress standard with regard to visibility improvement."

RESPONSE: The regulation cited, 40 C.F.R. §51.308(e)(2)(i), addresses alternative measures States may opt to implement or require participation in rather than to require sources subject to BART to install, operate, and maintain BART. The revised SIP under review is not a proposal for an alternative to BART, it is the revision and resubmission of the State's BART determination for the PSO Northeastern Power Station; therefore, the cited reference does not apply.

DEQ has the authority to revise the SIP as necessary. When presented with a long-term multi-media, multi-pollutant targeted proposal, which provided a definitive lifespan for the two coal-fired boilers at the Northeastern Power Station, it was appropriate for the State to reopen and review the BART determination. The BART determination as described in the proposed SIP revision, while crediting the facility for all reductions inherent in the multi-media, multi-pollutant targeted approach, provides a more cost effective control technology given the defined lifespan of the units than the BART determination contained within the FIP. It is not necessary that the BART determination in the proposed SIP revision achieve greater visibility improvement than the determination within the FIP, since it is not a "Greater Reasonable Progress Alternative Determination" under 40 C.F.R. §51.308(e)(2). It is only necessary that the BART determination be compliant with the five factor analysis under 40 C.F.R. §51.308(e)(1) and Appendix Y.

30. **COMMENT:** "In addition, a significant portion of the emissions reductions attributed to the Proposal could also be achieved by switching to ultra-low sulfur coal (as recommended by DEQ's original SIP) and by installing DSI control technology to meet requirements of the MATS rule, which would be necessary by 2016 even if the Proposal did not exist. For example, by simply switching to ultra-low sulfur coal PSO could reduce total forecasted SO_2 emissions on its system by approximately 33%, while the addition of DSI controls, which is required by MATS, produces approximately 67 thousand tons (6.4%) of the total forecasted SO_2 removal attributed to the Proposal. The DSI emission reductions cannot be used to achieve greater reasonable progress because it must be: 'demonstrat[ed] that the emission reductions resulting from the emissions trading program or other alternative measure will be surplus to those reductions resulting from measures adopted to meet requirements of the CAA as of the baseline date of the SIP.' 40 C.F.R. § 51.308(e)(2)(iv) (emphasis added)."

"By including emissions reductions arising from DSI and by ignoring reductions which could be achieved through switching to ultra-low sulfur coal, the Proposal overstates the emissions reductions due to the Proposal which are surplus to reductions that were achievable through other control measures or by implementing measures to meet CAA requirements that existed as of the baseline date of the revised SIP."

RESPONSE: As previously stated, the proposed SIP revision under review is a revision and resubmission of the State's BART determination for the PSO Northeastern Power Station and is not a proposal for an alternative to BART; therefore, greater reasonable progress is not an issue. Further, installation of the DSI control technology to satisfy the BART requirements will provide confidence that the facility will also be able to meet the requirements of the MATS rule. It is not accurate that a significant portion of the emissions reductions attributed to the "Proposal" can be achieved with ultra-low sulfur coal and DSI. Over the same time period, April 16, 2016 through December 31, 2026, the proposed SIP revision would result in the removal of approximately 65,000 tons more SO_2 than the scenario outlined in the comment.[6]

31. **COMMENT:** "Also, any alternative to BART must require that: 'all necessary emission reductions take place during the period of the first long-term strategy for regional haze.' 40 C.F.R. §51.308(e)(2)(iii). The first long-term strategy period ends in 2018. However, the Proposal fails to meet this requirement, because the level of SO_2 emissions under the Proposal is expected to be significantly higher than emissions under the DFGD alternative until well after 2018. SO_2 emissions will only be lower when the second Unit is retired. The SO_2 emission rate for DSI (estimated at 0.4 pounds per MMBtu) is six point six times the forecasted emission rate of the Units (0.06 pounds per MMBtu) with DFGD control technology."

"Accordingly, the Proposal cannot be adopted as a formal alternative to BART, and it should be withdrawn."

RESPONSE: As previously stated, the proposed SIP revision under review is a revision and resubmission of the State's BART determination for the PSO Northeastern Power Station, and is not a proposal for an alternative to BART. For more detail, please see Response to Comment No. 29.

32. **COMMENT**: The comment questions the assertion on page 12 of the Revised BART Report that it expects cumulative SO_2 and NO_x emissions from the Units to be approximately 36% of the emissions level that would result from the DFGD retrofit option. Underlying details of the analysis supporting the above assertion were not

[6]This response assumes the commenter used a 0.6 lb/MMBtu SO2 emission rate for ultra-low sulfur coal to arrive at the asserted 33% reduction in the comment. DSI control efficiencies are dependent on many site-specific considerations. Removal efficiencies can range from 30% to 70% for SO2. It is reasonable to assume that DSI would have a lower control efficiency for ultra-low sulfur coal; however, for this comparison it was assumed that the DSI could achieve a 50% control efficiency and that the facility would have no capacity restrictions under the scenario proposed in the comment. Emission calculations for the DEQ alternative are documented in the revised BART determination.

provided with the Revised BART Report. Absent back-up documentation, that assertion is unreliable and cannot be used to justify the Proposal.

RESPONSE: All assumptions relied upon were available in the determination. In EPA's assessment of the cost effectiveness of the DFGD retrofit option, the capital recovery factor used to establish the annualized costs assumed a lifespan of 30 years. This is referenced on page 6 of the revised BART determination. Since the FIP does not restrict capacity utilization, no such restrictions were assumed in this calculation. The mass of emissions attributable to the EPA FIP is a simple multiplication of the emission rate – found in Tables 2 (for NO_x) and 8 (for SO_2) of the revised BART determination – and full load heat input (see Table 9), and continuous operation for 30 years. The assumptions for the corresponding emission calculations under the agreement can be found in Tables 2 and 3 of the revised BART determination. Minor differences in calculations can arise through rounding and whether emissions in 2016 are prorated by remaining months or days.

While the revised BART determination does not significantly rely on this particular calculation, it provides a reasonable tool for comparing the results of the FIP with those of the long term multi-media, multi-pollutant targeted proposal.

33. **COMMENT**: "In addition, the Proposal ignores the additional NO_x emissions that would be produced by gas-fired generation or purchased power sources that PSO would have to acquire to replace the Units after they are retired in 2016 and 2026. Finally, it was assumed that, if DFGD retrofitted, the Units would operate for another 30 years (i.e., until 2046). There is no support for this assumption. In fact, PSO has stated in testimony in OCC Cause No. PUD 201200054 that it expects the Units would likely be retired by 2030 (i.e. 13 years after DFGD retrofits are implemented). If the emissions analysis was adjusted to reflect a shorter remaining operating life of the Units, consistent with PSO's own forecast, and to account for NO_x emissions produced from sources that replace the Units, the estimated emissions reduction attributable to the Proposal would likely be eliminated."

RESPONSE: As discussed in Response to Comment No. 28, replacement energy is not a component of a BART review. However, staff notes that any replacement energy is unlikely to be procured from a source with environmental impacts comparable to or greater than those of the two existing coal-fired units under review. In establishing the requirement for BART, the Clean Air Act required the states to address a specific group of existing large-emitting sources that were placed in operation before many of the current national air quality programs were in place. Replacement energy would likely come from a source that is subject to either a BART review itself, or an environmental impact review through the Prevention of Significant Deterioration (PSD) program. Any in-state or out-of-state sources of replacement energy would also be subject to scrutiny regarding their potential visibility impacts on any Class I area.

Adequate support for the analyses' assumption of a 30-year life-span for the controls and units under the FIP scenario is provided in the revised BART determination, PSO's Supplemental BART Determination Information, and EPA's Technical Support

Document (TSD) published with the FIP. DEQ does not concur with the comment's concluding presumption that a shorter remaining operating life of the Units would negate emissions reduction attributable to the Proposal. It should be noted that a shorter operating life for the DFGD retrofits under the FIP scenario would decrease the cost-effectiveness of these controls.

34. **COMMENT**: "The BART analysis is based on outdated planning assumptions. The BART analysis supporting the Proposal is based on PSO long-term planning studies that are no longer valid. On April 9, 2013, the Company announced to the OCC that it will have to update its Integrated Resource Plan ('IRP') to reflect previously unanticipated increases in near-term peak demand due to recent significant growth in oil and gas production activities on its system. These changes will increase replacement costs for the Units and also increase future SO_2 and NO_x emissions on PSO's system, and thereby could significantly alter results of the BART analysis supporting the Proposal. Due to these material changes, DEQ's current BART analysis is no longer valid and therefore needs to be revised once PSO's updated IRP is completed and approved by the OCC later this year."

RESPONSE: As discussed in the Response to Comment No. 28, replacement energy is not a component of a BART review. The BART determination relies upon the Supplemental BART Determination Information submitted by PSO, and the terms and conditions in the First Amended Regional Haze Agreement. Accordingly the Regional Haze Agreement provides that: (1) the facility will shut down one of the affected units (either Unit 3 or 4) by April 16, 2016; (2) the facility will install and operate a dry sorbent injection ("DSI") system on the remaining unit to meet an emission standard of 0.40 lb/mmBTU or less from April 16, 2016 to December 31, 2026; and (3) the facility will incrementally decrease capacity utilization for the remaining unit between 2021 and 2026, and will shut down the remaining unit no later than December 31, 2026. This agreement is with PSO for two boilers at the Northeastern Power Station. For further response, please refer to Response to Comment No. 11.

35. **COMMENT**: "Ratepayer Impacts have been ignored. The Proposal completely ignores the potentially devastating impact of the Proposal on PSO's ratepayers, presumably because EPA doesn't consider such impacts relevant in a BART analysis. However, as we have shown herein, the Proposal cannot be BART or a formal BART alternative. In that context, EPA has recognized that utility companies can consider 'any potential impact on rates.' 76 FR 81749 (Dec. 28, 2011). See also, 27A O.S. 2-5-107(4) (2011) (economic impacts are to be considered). Accordingly, the potentially devastating impact of the Proposal on PSO's ratepayers must be considered here. Evidence presented by PSO in OCC Cause No. PUD 201200054 indicates that the Proposal may significantly increase costs to ratepayers. Parties have presented testimony in OCC Cause No. PUD 201200054 to the effect that the Proposal could increase rates by 15% to 19% in 2016, and that future rate increases due to the Proposal are expected to be much larger. Moreover, PSO's own analysis in OCC Cause No. PUD 201200054 indicates that the costs to ratepayers are expected to be approximately $1.9 billion higher under the Proposal than they would be under the DFGD retrofit alternative over the 2016-2040 period. This independent analysis by PSO further confirms that the Proposal is not cost effective when compared to the

DFGD alternative. Moreover, estimates presented by OIEC in testimony presented in OCC Cause No. PUD 201200054 indicate that the Proposal could be approximately $5 billion more costly to ratepayers than the low sulfur coal alternative which was designated by DEQ as BART in its original SIP."

RESPONSE: The *Federal Register* reference cited, 76 Fed.Reg. 81749 (Dec. 28, 2011), addressed the company's freedom to reduce emissions by alternative methods so long as the BART determined emission limit is met, "emission limits may also be met with reconfiguration of the units to burn natural gas, the companies themselves are free to determine whether this option best responds to future customer needs and preferences, including any potential impact on rates." This statement remains true within the restrictions imposed by the Regional Haze Agreement.

The statute referenced in the comment, 27A O.S. § 2-5-107(4), only applies to the considerations required by the Air Quality Advisory Council in deciding whether to recommend a rule or rule amendment to the Environmental Quality Board. Since the revised BART determination is not a rule, § 2-5-107(4) does not apply. For a similar discussion, see Response to Comment No. 10.

As identified in the comment itself, a utility company's long term plans and issues related to utility rates are under the purview of the Oklahoma Corporation Commission.

36. **COMMENT:** In summary, the basis for the Proposal may be void, the Proposal impermissibly mandates retirement of the Units, it is approximately $242 million per year more costly than the existing BART (DFGD retrofit) alternative, would result in higher SO_2 emissions and lower visibility, and is forecasted to result in much larger rate increases than the DFGD retrofit option. The cost of the Proposal is also far higher than the ultra-low sulfur fuel switch alternative which DEQ determined to be BART in the original SIP and is approximately three to eight times the cost of BART proposals approved by EPA for other coal plants. Accordingly, the Proposal does not meet the criteria established by the EPA for approval as BART, or as an alternative to BART, and it is not in the interest of PSO's ratepayers. The Proposal should, therefore, be withdrawn.

RESPONSE: This comment summarizes concerns that have been addressed in Responses to Comments Nos. 26 through 35. DEQ believes that the Proposal meets the criteria established by the EPA for approval as BART.

Office of the Secretary of Energy, State of Oklahoma – Letter received via email on May 20, 2013 from James P. Albert, Deputy Secretary of Energy

37. **COMMENT:** "Understanding that mitigation options for these rules [Regional Haze and EPA's Mercury and Air Toxics Standards (MATS)] are inextricably intertwined, the Governor encouraged a holistic and reasonable state-based compliance strategy."

"[T]he EPA, the U.S. Department of Justice, PSO, and the State of Oklahoma … worked diligently to ensure that the agreed upon compliance strategy would provide greater regulatory certainty by ensuring compliance with both Regional Haze and MATS, and that this could be accomplished by mitigating costs to consumers. Notably this course of compliance offers greater flexibility regarding thresholds for emissions reductions, it significantly eliminates the risk that substantial capital costs will be passed along to ratepayer if investments are made in compliance technologies that are later deemed insufficient for addressing future environmental regulations, and it protects Oklahoma's environment and the health of Oklahoma citizens. And this all made possible greater reliance on Oklahoma's native resources, which are creating local jobs and support local economies."

"The settlement agreement offers the 'lowest, *risk-adjusted* reasonable cost option for compliance' and offers promise for future compliance as well with far lower capital risk. Inaction, which would place ratepayers, system reliability, and Oklahoma's environment at risk, simply cannot be an option."

RESPONSE: DEQ acknowledges the comment in support of the proposed SIP revision.

Office of the Secretary of Environment, State of Oklahoma – Letter dated May 20, from Gary Sherrer, Secretary of Environment

38. COMMENT: "This Oklahoma-based plan and the resulting SIP were carefully crafted and vetted to be in both technical and legal compliance with the Clean Air Act and to serve as the replacement for the FIP. This SIP allows for compliance, while also putting AEP/PSO on a path that works best for them and their customers. In addition to meeting Regional Haze requirements, the settlement agreement also is designed to bring AEP/PSO into compliance with the Mercury and Air Toxics Rules and various other air rules."

RESPONSE: DEQ acknowledges the comment in support of the proposed SIP revision.

Oklahoma Sierra Club – Comments submitted at the public hearing by Jody Harlan, Chair

39. COMMENT: Ms. Harlan expressed support for this option [the proposed revision of BART] because it is more cost effective than retrofitting coal units with expensive scrubbers. Continuing to run the outdated, aging plants until 2041 would raise rates for residential customers by 14.3% compared to a projected 11% under PSO's cost-effective plan.

RESPONSE: DEQ acknowledges the information provided.

40. COMMENT: "Dangerous sulfur dioxide emissions from the Northeastern power plant near Oologah will be reduced by more than half in 2016 and fully eliminated by 2026."

"'Oklahomans' health will benefit from cumulative reductions in carbon dioxide, the primary cause of climate disruption, and sulfur dioxide, mercury, nitrogen oxides and other toxins."

RESPONSE: DEQ acknowledges the information provided.

41. **COMMENT:** **"**The proposed SIP revision for the AEP-PSO Northeastern Units 3 and 4 avoids the risks of expensive investments in outdated technology. It allows AEP-PSO flexibility in transitioning to cleaner energy sources over a reasonable period of time. And it enables Oklahoma to comply with federal regulatory safeguards while ensuring that we will have a cleaner energy future."

RESPONSE: DEQ acknowledges the comment in support of the proposed SIP revision.

Quality of Service Coalition (QOSC) – Letter dated May 20, 2013 from Lee Paden, Attorney for Quality of Service Coalition

42. **COMMENT:** "ODEQ is required to consider and address the anticipated net effect on visibility resulting from changes projected in point, area, and mobile source emissions by 2018. As explained on Page 91 of the Regional Haze Implementation Plan Revision, February 2, 2010, the changes anticipated to occur will result from population growth, land management evolution, air pollution control, and development of industry, energy and natural resources. There is no indication in the most recently filed [Proposed] Regional Haze Implementation Plan Revision, March 20, 2013, that ODEQ used modeling data that contains updated emissions inventory data. To establish emissions in 2018 from the 2002 inventory, ODEQ, using CENRAP modeling expertise, developed an estimated inventory for 2018. QOSC respectfully suggests that the use of data that is outdated is inappropriate, requires additional data be supplied and would suggest that more current emission inventory data be used in modeling of regional haze in 2018. The use of new data inserted in the CENRAP model and the results of new modeling information will provide ODEQ and EPA information required by regional haze statutes and rules."

"Only recently EPA noted that Arizona Department of Environmental Quality failed to provide the most recent emissions inventory available as required by the Regional Haze Rule in 40 CFR 51.308(d)(4)(v), in addressing it [sic] updated Regional Haze submission. Arizona subsequently provided the 2008 emissions inventory. ODEQ should also be required to provide the most recent emissions inventory available to use in creating an estimated inventory for 2018. An updated emissions inventory is essential to the overall determination of BART-eligible sources in Oklahoma and to the determination of sources required to install BART."

RESPONSE: The regional photochemical modeling conducted in support of the initial SIP was not updated for the SIP revision,[7] because individual BART determinations do not rely on the regional photochemical modeling conducted in cooperation with

[7] The proposed SIP revision opens and revises only the disapproved portions of the original SIP revision, and only as they relate to the SO_2 BART Determination for AEP/PSO Northeastern Units 3 and 4. Those portions include the BART chapter (Chapter VI), the Long-term Strategy with Emission Reduction (Chapter VII), the BART Application Analysis (Appendix 6-4) for AEP/PSO Northeastern Units 3 and 4, and the Regional Haze Agreement (Appendix 6-5) for AEP/PSO. The proposed SIP revision also addresses the portions of Oklahoma's Interstate Transport SIP disapproved by EPA because it relied on the original BART Determination for AEP/PSO's Northeastern Units 3 and 4.

CENRAP. In fact, regional photochemical modeling conducted over 12 and 36 kilometer grid scales is not designed to be used for single-source analysis. Instead, EPA requires that the more conservative Gaussian puff model, CALPUFF, be used for the review of long range impacts (greater than 50 kilometers) of individual sources. The model was developed to support evaluations of individual sources on Class I areas and provides both visibility and concentration results. The contributions to visibility impairment from PSO's Northeastern Power Station were evaluated with CALPUFF in the revised BART determination, and an updated inventory would have no impact on the BART determination for the facility.

DEQ notes that while EPA did require Arizona to submit the most recent available Emissions Inventory (2008) as part of its original Regional Haze SIP submittal (78 Fed.Reg. 29292 (May 20, 2013), Arizona was not required to update the regional photochemical modeling using the 2008 Emissions Inventory. As required, DEQ submitted an up-to-date Emissions Inventory in Appendix 4-1 of the original Regional Haze SIP submittal. All requirements of the scheduled progress reports and updates under the Regional Haze Program will be met.

43. **COMMENT:** "Again, the [Proposed] Regional Haze Implementation Plan Revision filed on March 20, 2013, is inconsistent with the February 2, 2010, Regional Haze Implementation Plan Revision. On page 111, D. Factors for Consideration (1). Source Retirement and Replacement Schedules, ODEQ opined that it considered source retirement and replacement schedules developing its long-term strategy of emissions reductions. ODEQ concluded that it "cannot reliably predict the retirement or replacement of sources and consequently does not rely on source retirement to achieve any reasonable progress goal. Nothing in the [Proposed] Regional Haze Implementation Plan Revision provides the rationale or reasoning for ODEQ's new position on retirement or replacement of sources. Even more interesting is the lack of any information in the March 20, 2013 document addressing replacement of retired generating facilities in 2016 or 2026."

RESPONSE: Absent a federally or state enforceable mechanism to enforce an otherwise voluntary retirement, retirements cannot be dependably predicted or relied upon for the Reasonable Progress Goal planning discussed in Chapter IX of the original Regional Haze SIP submittal. The First Amended Regional Haze Agreement signed by PSO and DEQ provides an enforceable mechanism to allow contemporaneous emission reductions achieved through retirement to be relied upon within the context of the SIP's implementation of BART requirements. This document is referred to and included in the appendices of the proposed SIP revision. For a response to the issue of replacement power, please see Response to Comment No. 28

44. **COMMENT:** "Reasonable progress goals require ODEQ to consider 5 factors in determining a reasonable progress goal. 42 U.S.C. Section 7491(g) (1) provides the five factors that must be considered in determining a reasonable progress goal:

1. Cost of compliance
2. Time necessary for compliance
3. Energy effects of compliance

4. Non-air quality environmental effects of compliance, and
5. Remaining useful life of existing sources

QOSC suggests that factor number 3, if considered at all, did not factor into its consideration the requirement for replacement energy and capacity as existing units are retired."

RESPONSE: As indicated in the Response to Comment No. 43, this proposed SIP revision does not propose changes to the EPA-approved version of Chapter IX (Reasonable Progress Goals) of the original SIP revision; however, it does identify further reasonable progress actions which will certainly further these goals (relevant to the requirements of the Federal Clean Air Act ("CAA") § 169A(g)(1), 42 U.S.C. § 7491(g)(1)). The revised BART Determination considers "the energy and non-air quality environmental effects of compliance" (CAA § 169A(g)(2), 42 U.S.C. § 7491(g)(2)). As recommended in 40 CFR Part 51, Appendix Y, Section IV.D, Step 4(h), this portion of the analysis focused primarily on energy requirements of the control technology, and followed an approach consistent with the statement in Step 4(h)(1): "Because energy penalties or benefits can usually be quantified in terms of additional cost or income to the source, the energy impacts analysis can, in most cases, simply be factored into the cost impacts analysis."

Regarding consideration of the requirement for replacement energy and capacity as existing units are retired, please refer to Response to Comment No. 28.

45. **COMMENT:** "Replacement energy for the 490 MW unit retired in 2016 must be immediately available upon retirement and the amount of replacement energy and costs associated with that replacement energy are readily quantifiable. These costs are necessary costs of compliance and without their inclusion in the review process, ODEQ cannot properly determine if the scheme of retirement suggested in the Settlement Agreement is acceptable."

RESPONSE: See Response to Comments No. 28.

46. **COMMENT:** Adopt by reference OIEC submitted comments.

RESPONSE: See Responses to Comments Nos. 26 through 36.

47. **COMMENT:** This comment suggests that "the [Proposed] Regional Haze Implementation Plan does not meet statutory and regulatory requirements necessary for approval of this proposal. QOSC recommends its rejection. In the best interest of Oklahoma customers of PSO, the state of Oklahoma and all Oklahoma citizens, the proposal should be withdrawn by ODEQ."

RESPONSE: No substantive deviations from the statutory or regulatory requirements applicable to the proposed SIP revision have been identified; consequently, the proposed SIP revision has not beenwithdrawn.

Sierra Club – Letter (and enclosure) received via email on May 20, 2013 from Elena Saxonhouse, Staff Attorney

48. **COMMENT:** "I write on behalf of Sierra Club and its 2.1 million members and supporters, including more than 3,000 members in Oklahoma, in strong support of the proposed Regional SIP Revision. The SIP fully complies with federal requirements to reduce regional haze and interstate pollution from the Northeastern coal-fired power plants in Oologah, Oklahoma. In addition to protecting scenic view in the region's most treasured parks, the SIP's requirement to retire one Northeastern unit by 2016, along with retrofits and steady ramp down of capacity at the other toward retirement in 2026, will have enormous public health benefits. It is also a more cost effective solution than requiring the installation of expensive scrubbers on both units. For these reasons, Sierra Club urges the Oklahoma Department of Environmental Quality (DEQ) to promptly approve and finalize the SIP." The commenter also pointed out that the SIP Revision will conserve water resources and is consistent with the State Energy Plan.

RESPONSE: DEQ acknowledges the comment in support of the proposed SIP revision. No additional response is necessary.

49. **COMMENT:** "The SIP Revision's impact on the state's dwindling water resources is also worth noting in light of the extreme drought conditions facing Oklahoma, and DEQ's mandate to consider nonair environmental impacts. In response to Sierra Club data requests in proceedings before the Oklahoma Corporation Commission, PSO has estimated that the increase in water consumption at the Northeastern plant if it were to add dry scrubbers to both units would be at least 65 times greater than with a retrofit ACI and DSI at one unit pursuant to the SIP Revision." The commenter provided, as Exhibit 1, Public Service Company of Oklahoma's Response to Sierra Club's Fifth Set of Data Requests, which stated that the controls pursuant to the EPA settlement will consume approximately 11,250 gallons of water per day, compared with the DFGD option, which would consume approximately 737,000 to 805,000 gallons of water per day for two units.

RESPONSE: The Revised BART determination took into consideration non air quality environmental impacts, including the estimated water requirement for proper operation of each control option.

50. **COMMENT:** "The state then has the discretion to choose the 'best' option, so long as it has considered the above factors consistent with the BART guidelines, and 'provide[d] a justification.' 70 Fed. Reg. at 39,170-71. For all the reasons, above, Sierra Club believes DEQ correctly and justifiably chose the alternative that provides for the gradual phase out of the Northeastern coal units. We enthusiastically support the SIP Revision and urge DEQ to promptly move forward with finalizing and implementing the rule."

RESPONSE: DEQ acknowledges the comment in support of the proposed SIP revision. No additional response is necessary.

State Chamber of Oklahoma – Letter dated May 20, 2013 from Fred S. Morgan, President and CEO

51. **COMMENT:** "The State Chamber of Oklahoma supports the state implementation plan (SIP) over the less desirable option of an EPA-designed compliance plan. Without the

SIP, the Public Service Company of Oklahoma (PSO) will be forced to comply with a federal implementation plan (FIP), which would inevitably come with a greater cost to Oklahoma rate payers – business and residential customers."

RESPONSE: DEQ acknowledges the comment in support of the proposed SIP revision.

Susan Schmidt, Sierra Club member – Comments submitted at the public hearing

52. **COMMENT:** "It's time we stop using coal. PSO needs to follow-through with the SIP to retire the Northeastern unit by 2016 as agreed and ramp up its plans to transition away from coal. It's past time that all utility companies embrace clean energy."

RESPONSE: DEQ acknowledges the comments in support of the proposed SIP revision.

Trinity Consultants – Comment submitted at public hearing by Jeremy Jewell, Principal

53. **COMMENT:** Mr. Jewell provided a description of the technical analyses done by Trinity for PSO's BART reevaluation. He provided a description of the modeling analyses conducted by Trinity for PSO. Regarding cost of control estimates prepared by Trinity, the commenter stated that EPA's Control Cost Manual was used and PSO's engineering cost estimates were presented for comparison purposes only. The results of the control cost evaluations show that the scenario presented in the proposed SIP revision is the most cost effective scenario that also achieves the necessary visibility improvement goal.

RESPONSE: DEQ acknowledges the information provided.

Oklahoma Sierra Club – Compilation of 380 Sierra Club members' and supporters' comments collected online, submitted via email on May 20, 2013, by Whitney Pearson, Associate Organizing Representative.

54. **COMMENT:** The comment from each of the commenters expressed support for the proposal as a step in protecting and improving public health.

RESPONSE: DEQ acknowledges the comments in support of the proposed SIP revision.

Citizens' Comments – Compilation of comments received via email May 16 – May 20, 2013

55. **COMMENT:** David Brooke commented that he does not understand how PSO's "alleged pollution" would affect the wildlife in southwest Oklahoma. He also expressed concern about adequate energy sources if coal plants are closed.

RESPONSE: The original Regional Haze SIP submittal documented, using appropriate and relevant data and modeling protocols, that BART-eligible units at PSO's Northeastern Power Station cause or contribute to visibility impairment at the Wichita Mountains Wilderness Area and other Class I areas. As a result, those units became subject to BART requirements, as described. Regarding concerns over availability of adequate energy sources, see Response to Comment No. 28.

56. **COMMENT:** Steve Jackson – Does not want EPA and Sierra Club to raise his electricity rates.

RESPONSE: DEQ acknowledges the commenter's concern over a possible increase in customers' utility rates as a result of implementation of the proposed SIP revision. However, as discussed in the Response to Comment No. 28, this issue is not within the scope of DEQ's review authority under the Regional Haze program.

57. **COMMENT:** Bonnie and Jeff Brown – No utility increase.

RESPONSE: Please refer to Response to Comment No. 56.

58. **COMMENT:** Cheryl Carman – "We cannot afford a raise in our utility bills."

RESPONSE: Please refer to Response to Comment No. 56.

59. **COMMENT:** Jan Mayfield – Cannot afford another increase in utility bills.

RESPONSE: Please refer to Response to Comment No. 56.

60. **COMMENT:** Corey Smith – "I respectfully request that the push by the Sierra Club and EPA to raise our rates be denied."

RESPONSE: Please refer to Response to Comment No. 56.

61. **COMMENT:** Patrick Sullivan – "I oppose implementation of the proposed changes which will radically increase our electric bills."

RESPONSE: Please refer to Response to Comment No. 56.

62. **COMMENT:** Nancy Hollingshed – Opposes proposed utility rate hikes.

RESPONSE: Please refer to Response to Comment No. 56.

63. **COMMENT:** Peggy Grotts -- "We don't want a PSO rate increase in Oklahoma!"

RESPONSE: Please refer to Response to Comment No. 56.

64. **COMMENT:** Carolyn VanHorn – "We do not want any rate increases for our power in the state of Oklahoma!"

RESPONSE: Please refer to Response to Comment No. 56.

65. **COMMENT:** Felice Hill – Requests that the plan be rejected; does not want utility rates increased.

RESPONSE: Please refer to Response to Comment No. 56.

66. **COMMENT:** Cris Kurtz – Opposes higher utility rates.

RESPONSE: Please refer to Response to Comment No. 56.

67. **COMMENT:** Jonathan Ballard – Is against mandates that raise utility rates.

RESPONSE: Please refer to Response to Comment No. 56.

68. **COMMENT:** Beverly Brown – Opposes the increase in utility rates.

RESPONSE: Please refer to Response to Comment No. 56.

AEP/PSO – Transcript of Direct Testimony of Howard L. Ground, on behalf of Public Service Company of Oklahoma (PSO), September 26, 2012 submitted by Howard L. "Bud" Ground, Manager, State Governmental and Environmental Affairs, PSO, a subsidiary of American Electric Power Company, Inc. (AEP) to support his oral comments.

69. **COMMENT**: PSO's environmental compliance plan, which is how PSO refers to this plan and the revised state implementation plan, are an Oklahoma solution. When EPA finalized the Federal Implementation Plan, PSO and state government representatives knew that Oklahoma could come up with a better plan than those in the Federal Implementation Plan. PSO started working at the invitation of the Secretary of Energy and Secretary of Environment, to come up with a plan that would cost less and be better for our customers and our company than installing 800 million dollars or so worth of control equipment on 30-plus-year-old coal units. PSO developed this plan with the DEQ, Secretary of Environment, Secretary of Energy, and in consultation with the Attorney General and the Governor, at the time, and then took that plan to EPA. This is not a plan that EPA, some might say, forced on PSO. This is something that PSO initiated and negotiated with EPA. Pages 23 and 24 of the Transcript of Direct Testimony provide a description of the process and participants involved in the development of the Oklahoma solution and PSO's environmental compliance plan.

RESPONSE: DEQ acknowledges the comment in support of the proposed SIP revision.

70. **COMMENT:** This environmental compliance plan provides for environmental benefits while ensuring the continued reliability and mitigating risks for future environmental regulations. PSO wanted to make sure that the plan met not only the requirements of the Regional Haze rule but also the requirements of the mercury and air toxics rule (MATS). Also, PSO wanted to make sure that it would not be necessary to install additional control equipment on units that through this plan were scheduled to be retired. Additionally, PSO wanted the plan to take care of other air, water, and solid waste issues that were expected to be addressed in EPA regulations in the very near future.

From Direct Testimony, pages 6 and 7, "[t]here are two main current EPA rules requiring PSO to install control equipment to meet emission limits in specific time frames: (1) the Regional Haze Rules (RHR) and (2) the Mercury and Air Toxics Standard (MATS) rule. PSO also faces the prospect of additional costly requirements in the future for its generation fleet, particularly its coal fleet. Over the next five to ten years, PSO will likely have to address requirements under: (1) the successor to the Cross

State Air Pollution (CSAPR), (2) the Coal Combustion Residuals (CCR) Rule, (3) the Clean Water Act (316 (b)) Rule, (4) possible carbon dioxide limitations and other greenhouse gas (GHG) regulations, (5) implementation obligations under the one-hour SO_2 and NO_x Primary National Ambient Air Quality Standards (NAAQS), (6) future revisions of the ozone and particulate matter NAAQS, and (7) a second planning period under the RHR."

RESPONSE: DEQ acknowledges the comment in support of the proposed SIP revision.

Oral Comments

Gary Sherrer, Secretary of the Environment

Oral Comments are included in Written Comments No. 38.

John Dirickson, Oologah

71. **COMMENT:** "We are for and in support of Public Service and their rehab plan, as they have a plan with the Environmental Protection Agency.

RESPONSE: DEQ acknowledges the comment in support of the proposed SIP revision.

Tom Schroedter, Executive Director of OK Industrial Energy Consumers

72. **COMMENT:** "[T]he DEQ SIP never published or posted the entire settlement agreement that was an exhibit - - should have been an exhibit to the – to DEQ's filing. That also may be a violation of the Open meetings Act which means DEQ must withdraw the proposal."

RESPONSE: The public hearing on the proposed SIP revision was not a meeting as defined in the Open Meeting Act (25 O.S. § 304) and, therefore, the Act does not apply. Even if the Act did apply to this type of hearing, the notice requirements of §§ 303 and 311(B) were satisfied. Section 303 provides that public notice shall "specify the subject matter or matters to be considered . . . ." Section 311(B) provides that "[a]ll agendas required pursuant to the provisions of this section shall identify all items of business to be transacted by a public body at a meeting . . . ." More than thirty days prior to the hearing in question, notice of the hearing was published in the Tulsa World, the Lawton Constitution, and the Oklahoman. In addition, DEQ posted notice of the public hearing on the agency's website, as well as the proposed SIP revision, appendices, and other related information.

The settlement agreement referenced in this comment is attached to the proposed SIP revision as Appendix I. Attachment B to the settlement agreement is a letter from EPA Assistant Administrator, Gina McCarthy, expressing support for the settlement agreement and indicating confidence that the provisions of the agreement will also result in compliance with EPA's Mercury and Air Toxics Rule. After reviewing this comment, DEQ determined that the settlement agreement was available on DEQ's website; however, the McCarthy letter was not attached electronically. Regardless, a hardcopy of the letter was available at DEQ's Oklahoma City office. In any event, the notice requirements of the Act would still be satisfied, because the Open Meeting Act does not require that the entire content of a document to be discussed at a meeting be published in full prior to the meeting. *See Andrews v. Ind. School Distr. No. 29 of Cleveland County,* 737 P. 2d 929, 931 (Okla. 1987). Rather, as was explained in Attorney General Opinion 82-81, "[t]he function of an agenda for a meeting of a public body is to provide the public with a factual explanation of matters to be taken up at a meeting of the public body." The published notice provided a sufficient description of the topics that were available for public comment at the hearing. The letter, an attachment to the settlement agreement, did not contain substantive information regarding the proposed SIP revision, which was the subject of the hearing. The letter is merely part of the recitals (or background) of the settlement agreement (not part of the agreement section) and the settlement agreement, itself, was merely included in the proposed SIP revision as background (not intended to be part of the BART evaluation or relied upon in the determination). Therefore, the omitted letter was merely background to the background of the proposed SIP revision.

Additional Oral Comments are included in Written Comment Nos. 26 through 36.

Bud Ground, Manager, Governmental and Environmental Affairs, PSO

Oral Comments are included in Written Comments Nos. 12 through 15.

Bob Rounsavell, President, Carrie Dickerson Foundation, Sierra Club member, resident of Oologah

Oral Comment is included in Written Comment No. 16.

John Laash for Dogwood Energy, LLC

Oral Comments are included in Written Comments Nos. 21 through 23.

Lee Paden, Attorney for Quality of Service Coalition

Oral Comments are included in Written Comments Nos. 42 through 47.

Susan Schmidt, Sierra Club member

Oral Comment is included in Written Comment No. 52.

Jamie Maddy, Director of Regulatory Affairs, Chesapeake Energy

Oral Comments are included in Written Comments Nos. 17 through 19.

Rick Chamberlain, representing Calpine Corporation

73. COMMENT: Calpine Corporation is an independent power producer of an 1100 megawatt privately owned natural gas generating plant located near Tulsa, Oklahoma. After conducting a competitive bid process that was overseen by an independent evaluator, PSO entered into a purchase power agreement with Calpine. Under this agreement, Calpine will provide 260 megawatts of natural gas fired generation capacity beginning 2016 to replace coal-fired generation capacity that is being curtailed.

RESPONSE: DEQ acknowledges the information provided by Calpine; however, replacement of generation capacity is not a component of the EPA-required cost effectiveness review in the Revised BART Determination *(see* Response to Comment No. 28 for further detail).

74. **COMMENT**: Calpine supports the revised SIP.

RESPONSE: DEQ acknowledges the comment in support of the proposed SIP revision.

A.J. Ferate, Devon Energy

Oral Comment is included in Written Comment No. 20.

Brandy Wreath, Director, Public Utilities Division, OK Corporation Commission

Oral statement at public hearing on May 20, 2013, by Brandy Wreath, Director of Public Utilities Division:

75. **COMMENT:** Mr. Wreath requested that "DEQ take a little bit more time before making a final decision . . . based on the concept that all of the relevant information" has not been considered. Mr. Wreath stated that "now we understand there's additional need for purchase power or additional generation possibly" as a result of the proposed SIP and the possibility of this new information warrants a delay in the final development of the proposed SIP.

RESPONSE: As discussed in further detail in the Response to Comment No. 28, the replacement power costs described in Mr. Wreath's comments are not within the scope of costs to be considered in making a BART determination pursuant to the relevant Federal regulations. In addition, on March 28, 2013, the Oklahoma Corporation Commission granted a Motion to Stay Proceedings filed by Mr. Wreath on February 21, 2013. In the Motion to Stay Proceedings, Mr. Wreath indicated that it is too early in the process to ask the Commission to approve costs related to the requirements that are contained in the proposed SIP revision and requested the Commission to "grant a stay in the proceedings …until a revised SIP has been received final approval by EPA." *See* Motion to Stay Proceedings filed by Brandy Wreath, Cause No. PUD 201200054 (Oklahoma Corporation Commission, Feb. 21, 2013). Therefore, it appears that the Oklahoma Corporation Commission is waiting on "final approval by EPA" before it considers all of the costs within its jurisdiction (including the cost of replacement power). Before EPA approval is possible, DEQ must finalize and submit a final proposed SIP revision to EPA for review. Therefore, it appears that the more expeditiously an approvable SIP revision is submitted to EPA, the sooner any costs associated with replacement power will be considered in the appropriate forum.

Jeremy Jewell, Principal, Trinity Consultants

Oral Comment is included in Written Comment No. 53.

Whitney Pearson, Sierra Club

Oral Comment is included in Written Comment No. 54.

Jody Harlan, Sierra Club -- Comments submitted at the public hearing by Jody Harlan, Chair.

Oral Comments are included in Written Comments Nos. 39 through 41.

Appendix VIII

Other Submittal Documents

LEGAL AUTHORITY

27A O.S. § 2-5-105 designates the Department of Environmental Quality (DEQ) as the administrative agency for the Oklahoma Clean Air Act (CAA). DEQ's Air Quality Division (AQD) handles the statutory authorities and responsibilities concerning air quality under OAC 252:4-1-3(c). The AQD has the authority to carry out all duties, requirements, and responsibilities necessary and proper for the implementation of the Oklahoma CAA and fulfilling the requirements of the federal CAA under 27A O.S. §§ 1-3-101(B)(8), 2-3-101(E)(1), and 2-5-105. Upon recommendation of the Air Quality Advisory Council, the Environmental Quality Board has the authority under Oklahoma statutory law 27A O.S. § 2-5-106 to adopt air quality regulations for DEQ. DEQ has the authority under Oklahoma law to:

- Enforce those regulations and orders of DEQ [27A O.S. §§ 2-5-105(4) and 2-5-110];
- Maintain and update an inventory of air emissions from stationary sources [27A O.S. § 2-5-105(19)];
- Establish a permitting program [27A O.S. § 2-5-105(2)]; and
- Carry out all other duties, requirements and responsibilities necessary and proper for the implementation of the Oklahoma CAA and the fulfillment of the requirements of the federal CAA [27A O.S. § 2-5-105(20)].

Specifically, the Environmental Quality Board and DEQ have the existing authority to:

- Adopt emissions standards and regulations to implement the Oklahoma CAA and fulfill requirements of the federal CAA [27A O.S. §§ 2-2-104, 2-5-105, 2-5-106, 2-5-107, and 2-5-114];
- Enforce the relevant laws, regulations, standards, orders and compliance schedules authorized by the Oklahoma CAA [27A O.S. §§ 2-5-105(4) and 2-5-110], and seek injunctive relief when necessary [27A O.S. §§ 2-5-105(14) and 2-5-117(A)];
- Abate pollutant emissions on evidence that the source is presenting an immediate, imminent and substantial endangerment to human health [27A O.S. § 2-5-105(15)];
- Prevent construction, modification, or operation of a source in violation of the requirement to have a permit, or in violation of any substantive provision or condition of any permit issued pursuant to the Oklahoma CAA [27A O.S. § 2-5-117(A)(2)];
- Obtain information necessary to determine compliance [27A O.S. §§ 2-5-105(17), (18)];
- Require recordkeeping, make inspections, and conduct tests [27A O.S. § 2-5-105(17)];
- Require the installation, maintenance and use of monitors and require emissions reports of owners or operators [27A O.S. § 2-5-112(B)(5)]; and
- Make emissions data available to the public [51 O.S. 1 through 24A.27, except §§ 24A.10a, 24A.11, 24A.12, 24A.15, 24A.16, 24A.16a, 24A.19, 24A.22, 24A.23, and 24A.24].

LEGAL AUTHORITY
Text of Referenced Rules & Statutes

Oklahoma Statutes:

Title 27A. Environment and Natural Resources
Chapter 1 - Oklahoma Environmental Quality Act
Article III - Jurisdiction of Environmental Agencies
Section 1-3-101 - Responsibilities and Jurisdiction of State Environmental Agencies

27A O.S. § 1-3-101:

A. The provisions of this section specify the jurisdictional areas of responsibility for each state environmental agency and state agencies with limited environmental responsibility. The jurisdictional areas of environmental responsibility specified in this section shall be in addition to those otherwise provided by law and assigned to the specific state environmental agency; provided that any rule, interagency agreement or executive order enacted or entered into prior to the effective date of this section which conflicts with the assignment of jurisdictional environmental responsibilities specified by this section is hereby superseded. The provisions of this subsection shall not nullify any financial obligation arising from services rendered pursuant to any interagency agreement or executive order entered into prior to July 1, 1993, nor nullify any obligations or agreements with private persons or parties entered into with any state environmental agency before July 1, 1993.

B. Department of Environmental Quality. The Department of Environmental Quality shall have the following jurisdictional areas of environmental responsibility:

1. All point source discharges of pollutants and storm water to waters of the state which originate from municipal, industrial, commercial, mining, transportation and utilities, construction, trade, real estate and finance, services, public administration, manufacturing and other sources, facilities and activities, except as provided in subsections D and E of this section;

2. All nonpoint source discharges and pollution except as provided in subsections D, E and F of this section;

3. Technical lead agency for point source, nonpoint source and storm water pollution control programs funded under Section 106 of the federal Clean Water Act, for areas within the Department's jurisdiction as provided in this subsection;

4. Surface water and groundwater quality and protection and water quality certifications;

5. Waterworks and wastewater works operator certification;

6. Public and private water supplies;

7. Underground injection control pursuant to the federal Safe Drinking Water Act and 40 CFR Parts 144 through 148, except for:

a. Class II injection wells,

b. Class V injection wells utilized in the remediation of groundwater associated with underground or aboveground storage tanks regulated by the Corporation Commission,

c. those wells used for the recovery, injection or disposal of mineral brines as defined in the Oklahoma Brine Development Act regulated by the Commission, and

d. any aspect of any CO_2 sequestration facility, including any associated CO_2 injection well, over which the Commission is given jurisdiction pursuant to the Oklahoma Carbon Capture and Geologic Sequestration Act;

8. Notwithstanding any other provision in this section or other environmental jurisdiction statute, sole and exclusive jurisdiction for air quality under the federal Clean Air Act and applicable state law, except for indoor air quality and asbestos as regulated for worker safety by the federal Occupational Safety and Health Act and by Chapter 11 of Title 40 of the Oklahoma Statute;

Added by Laws 1992, HB 2227, c. 398, § 6, eff. July 1, 1993; Amended by Laws 1993, HB 1002, c. 145, § 11, emerg. eff. July 1, 1993; Renumbered from 27A O.S § 6 by Laws 1993, HB 1002, c. 145, § 359, emerg. eff. July 1, 1993; Amended by Laws 1993, SB 361, c. 324, § 6, emerg. eff. July 1, 1993; Amended by Laws 1994, HB 1916, c. 140, § 24, eff. September 1, 1994; Amended by Laws 1997, SB 365, c. 217, § 1, emerg. eff. July 1, 1997); Amended by Laws 1999, SB 549, c. 413, § 4, eff. November 1, 1999); Amended by Laws 2000, SB 1223, c. 364, § 1, emerg. eff. June 6, 2000; Amended by Laws 2002, HB 2302, c. 397, § 1, eff. November 1, 2002; Amended by Laws 2004, SB 1204, c. 100, § 2, emerg. eff. July 1, 2004; Amended by Laws 2004, HB 2616, c. 430, § 11, emerg. eff. June 4, 2004; Amended by Laws 2009, SB 610, c. 429, § 8, emerg. eff. June 1, 2009; Amended by Laws 2012, HB 2365 c. 110, § 1, eff. November 1, 2012.

Title 27A. Environment and Natural Resources
Chapter 2 - Oklahoma Environmental Quality Code
Article II - Environmental Quality Board and Councils
Article Part 1. - Environmental Quality Board
Section 2-2-104 - Incorporation by Reference

27A O.S. § 2-2-104:

Insofar as permitted by law and upon recommendation from the appropriate Council, rules promulgated by the Environmental Quality Board may incorporate a federal statute or regulation by reference. Any Board rule which incorporates a federal provision by reference incorporates the language of the federal provision as it existed at the time of the incorporation by reference. Any subsequent modification, repeal or invalidation of the federal provision shall not be deemed to affect the incorporating Board rule.

Added by Laws 1994, SB 832, c. 353, § 3, emerg. eff. July 1, 1994.

Title 27A. Environment and Natural Resources
Chapter 2 - Oklahoma Environmental Quality Code
Article III - Department of Environmental Quality and Executive Director
Article Part 1. Department of Environmental Quality
Section 2-3-101 - Creation of Department of Environmental Quality

27A O.S. § 2-3-101:

A. There is hereby created the Department of Environmental Quality.

B. Within its jurisdictional areas of environmental responsibility, the Department of Environmental Quality, through its duly designated employees or representatives, shall have the power and duty to:

1. Perform such duties as required by law; and

2. Be the official agency of the State of Oklahoma, as designated by law, to cooperate with federal agencies for point source pollution, solid waste, hazardous materials, pollution, Superfund, water quality, hazardous waste, radioactive waste, air quality, drinking water supplies, wastewater treatment and any other program authorized by law or executive order.

C. Any employee of the Department in a technical, supervisory or administrative position relating to the review, issuance or enforcement of permits pursuant to this Code who is an owner, stockholder, employee or officer of, or who receives compensation from, any corporation, partnership, or other business or entity which is subject to regulation by the Department of Environmental Quality shall disclose such interest to the Executive Director. Such disclosure shall be submitted for Board review and shall be made a part of the Board minutes available to the public. This subsection shall not apply to financial interests occurring by reason of an employee's participation in the Oklahoma State Employees Deferred Compensation Plan or publicly traded mutual funds.

D. The Executive Director, Deputy Director, and all other positions and employees of the Department at the Division Director level or higher shall be in the unclassified service.

E. The following programs are hereby established within the Department of Environmental Quality:

1. An air quality program which shall be responsible for air quality;

Added by Laws 1992, HB 2227, c. 398, § 9, eff. January 1, 1993; Amended by Laws 1993, HB 1002, c. 145, § 16, emerg. eff. July 1, 1993; Renumbered from 27A O.S. § 9 by Laws 1993, HB 1002, c. 145, § 359, emerg. eff. July 1, 1993; Amended by Laws 1993, SB 361, c. 324, § 5, emerg. eff. July 1, 1993; Amended by Laws 1995, HB 1027, c. 246, § 1, eff. November 1, 1995; Amended by Laws 2002, HB 1980, c. 139, § 1, emerg. eff. April 29, 2002.

Title 27A. Environment and Natural Resources
Chapter 2 - Oklahoma Environmental Quality Code
Article V - Oklahoma Clean Air Act
Section 2-5-105 - Department Designated Administrative Agency for Oklahoma Clean Air Act for State - Powers

27A O.S. § 2-5-105:

The Department of Environmental Quality is hereby designated the administrative agency for the Oklahoma Clean Air Act for the state. The Department is empowered to:

1. Establish, in accordance with its provisions, those programs specified elsewhere in the Oklahoma Clean Air Act;

2. Establish, in accordance with the Oklahoma Clean Air Act, a permitting program for the state which will contain the flexible source operation provisions required by Section 502(b)(10) of the Federal Clean Air Act Amendments of 1990;

3. Prepare and develop a general plan for proper air quality management in the state in accordance with the Oklahoma Clean Air Act;

4. Enforce rules of the Board and orders of the Department and the Council;

5. Advise, consult and cooperate with other agencies of the state, towns, cities and counties, industries, other states and the federal government, and with affected groups in the prevention and control of new and existing air contamination sources within the state;

6. Encourage and conduct studies, seminars, workshops, investigations and research relating to air pollution and its causes, effects, prevention, control and abatement;

7. Collect and disseminate information relating to air pollution, its prevention and control;

8. Encourage voluntary cooperation by persons, towns, cities and counties, or other affected groups in restoring and preserving a reasonable degree of purity of air within the state;

9. Represent the State of Oklahoma in any and all matters pertaining to plans, procedures or negotiations for the interstate compacts in relation to the control of air pollution;

10. Provide such technical, scientific or other services, including laboratory and other facilities, as may be required for the purpose of carrying out the provisions of the Oklahoma Clean Air Act, from funds available for such purposes;

11. Employ and compensate, within funds available therefor, such consultants and technical assistants and such other employees on a full- or part-time basis as may be necessary to carry out the provisions of the Oklahoma Clean Air Act and prescribe their powers and duties;

12. Accept and administer grants or other funds or gifts for the purpose of carrying out any of the functions of the Oklahoma Clean Air Act;

13. Budget and receive duly appropriated monies and all other monies available for expenditures to carry out the provisions and purposes of the Oklahoma Clean Air Act;

14. Bring appropriate court action to enforce the Oklahoma Clean Air Act and final orders of the Department, and to obtain injunctive or other proper relief in the district court of the county where any alleged violation occurs or where such relief is determined necessary. The Department, in furtherance of its statutory powers, shall have the independent authority to file an action pursuant to the Oklahoma Clean Air Act in district court. Such action shall be brought in the name of the Department of Environmental Quality;

15. Take such action as may be necessary to abate the alleged pollution upon receipt of evidence that a source of pollution or a combination of sources of pollution is presenting an immediate, imminent and substantial endangerment to the health of persons;

16. Periodically enter and inspect at reasonable times or during regular business hours, any source, facility or premises permitted or regulated by the Department, for the purpose of obtaining samples or determining compliance with the Oklahoma Clean Air Act or any rule promulgated thereunder or permit condition prescribed pursuant thereto, or to examine any records kept or required to be kept pursuant to the Oklahoma Clean Air Act. Such inspections shall be conducted with reasonable promptness and shall be confined to those areas, sources, facilities or premises reasonably expected to emit, control, or contribute to the emission of any air contaminant;

17. Require the submission or the production and examination, within a reasonable amount of time, of any information, record, document, test or monitoring results or emission data, including trade secrets necessary to determine compliance with the Oklahoma Clean Air Act or any rule promulgated thereunder, or any permit condition prescribed or order issued pursuant thereto. The Department shall hold and keep as confidential any information declared by the provider to be a trade secret and may only release such information upon authorization by the person providing such information, or as directed by court order. Any documents submitted pursuant to the Oklahoma Clean Air Act and declared to be trade secrets, to be so considered, must be plainly labeled by the provider, and be in a form whereby the confidential information may be easily

removed intact without disturbing the continuity of any remaining documents. The remaining document, or documents, as submitted, shall contain a notation indicating, at the place where the particular information was originally located, that confidential information has been removed. Nothing in this section shall preclude an in-camera examination of confidential information by an Administrative Law Judge during the course of a contested hearing;

18. Maintain and update at least annually an inventory of air emissions from stationary sources;

19. Accept any authority delegated from the federal government necessary to carry out any portion of the Oklahoma Clean Air Act; and

20. Carry out all other duties, requirements and responsibilities necessary and proper for the implementation of the Oklahoma Clean Air Act and fulfilling the requirements of the Federal Clean Air Act.

Added by Laws 1992, HB 2251, c. 215, § 4, emerg. eff. May 15, 1992; Amended by Laws 1993, HB 1002, c. 145, § 42, emerg. eff. July 1, 1993; Renumbered from 63 O.S. § 1-1805.1 by Laws 1993, HB 1002, c. 145, § 359, emerg. eff. July 1, 1993; Amended by Laws 1993, SB 104, c. 47, § 1 (repealed by Laws 1994, HB 2299, c. 2, § 34, emerg. eff. March 2, 1994); Amended by Laws 1998, SB 986, c. 314, § 6, emerg. eff. July 1, 1998; Amended by Laws 2002, HB 2302, c. 397, § 2, eff. November 1, 2002.

Title 27A. Environment and Natural Resources
Chapter 2 - Oklahoma Environmental Quality Code
Article V - Oklahoma Clean Air Act
Section 2-5-106 - Authorizations of Board

27A O.S. § 2-5-106:

The Board is hereby authorized, after public rulemaking hearing and approval by the Council, to:

1. Promulgate, amend or repeal rules for the prevention, control and abatement of air pollution and for establishment of health and safety tolerance standards for discharge of air contaminants to the atmosphere; and

2. Promulgate such additional rules including but not limited to permit fees, as it deems necessary to protect the health, safety and welfare of the public and fulfill the intent and purpose of these provisions.

Added by Laws 1992, HB 2251, c. 215, § 5, emerg. eff. May 15, 1992; Amended by Laws 1993, HB 1002, c. 145, § 43, emerg. eff. July 1, 1993; Renumbered from 63 O.S. § 1-1806.1 by Laws 1993, HB 1002, c. 145, § 359, emerg. eff. July 1, 1993.

Title 27A. Environment and Natural Resources
Chapter 2 - Oklahoma Environmental Quality Code
Article V - Oklahoma Clean Air Act
Section 2-5-107 – Powers and Duties

27A O.S. § 2-5-107:

The powers and duties of the Council shall be as follows:

1. The Council shall recommend to the Board rules or amendments thereto for the prevention, control and prohibition of air pollution and for the establishment of health and safety tolerances for discharge of air contaminants in the state as may be consistent with the general intent and purposes of the Oklahoma Clean Air Act. The recommendations may include, but need not be limited to, rules required to implement the following:

a. a comprehensive state air permitting program,

b. an accidental release prevention program,

c. a program for the regulation and control of toxic and hazardous air contaminants,

d. a program for the regulation and control of acid deposition,

e. a small business program, and

f. a system of assessing and collecting fees;

2. The Council shall recommend rules of practice and procedure applicable to proceedings before the Council;

3. Before recommending any permanent rules, or any amendment or repeal thereof to the Board, the Council shall hold a public rulemaking hearing. The Council shall have full authority to conduct such hearings, and may appoint a hearing officer;

4. A rule, or any amendment thereof, recommended by the Council may differ in its terms and provisions as between particular conditions, particular sources, and particular areas of the state. In considering rules, the Council shall give due recognition to the evidence presented that the quantity or characteristic of air contaminants or the duration of their presence in the atmosphere, which may cause a need for air control in one area of the state, may not cause need for air control in another area of the state. The Council shall take into consideration, in this connection, all factors found by it to be proper and just, including but not limited to existing physical conditions, economic impact, topography, population, prevailing wind directions and velocities, and the fact that a rule and the degrees of conformance therewith which may be proper as to an essentially

residential area of the state may not be proper either as to a highly developed industrial area of the state or as to a relatively unpopulated area of the state;

5. Recommendations to the Board shall be in writing and concurred upon by at least five members of the Council;

6. The Council shall have the authority and the discretion to provide a public forum for the discussion of issues it considers relevant to the air quality of the state, and to:

a. pass nonbinding resolutions expressing the sense of the Council,

b. make recommendations to the Department concerning the need and the desirability of conducting public meetings, workshops and seminars, and

c. hold public hearings to receive public comment in fulfillment of federal requirements regarding the State Implementation Plan and make recommendations to the Department concerning the plan; and

7. The Council shall have the authority to conduct individual proceedings, to issue notices of hearings and subpoenas requiring the attendance of witnesses and the production of evidence, to administer oaths, and to take testimony and receive such pertinent and relevant proof as it may deem to be necessary, proper or desirable in order that it may effectively discharge its duties and responsibilities under the Oklahoma Clean Air Act. The Council is also empowered to appoint an Administrative Law Judge to conduct individual proceedings and prepare such findings of fact, conclusions of law and proposed orders as they may require. Upon issuance of a proposed order, the Council shall request that the Executive Director issue a final order in accordance with their findings or take such action as indicated and notify the respondent thereof in writing.

Added by Laws 1992, HB 2251, c. 215, § 7, emerg. eff. May 15, 1992; Amended by Laws 1993, HB 1002, c. 145, § 44, emerg. eff. July 1, 1993; Renumbered from 63 O.S. § 1-1808.1 by Laws 1993, HB 1002, c. 145, § 359, emerg. eff. July 1, 1993; Amended by Laws 1994, SB 832, c. 353, § 7, emerg. eff. July 1, 1994.

Title 27A. Environment and Natural Resources
Chapter 2 - Oklahoma Environmental Quality Code
Article V - Oklahoma Clean Air Act
Section 2-5-110 – Written Order to Violator of Oklahoma Clean Air Act

27A O.S. § 2-5-110:

A. In addition to any other remedy provided for by law, the Department may issue a written order to any person whom the Department has reason to believe has violated, or is presently in violation of, the Oklahoma Clean Air Act or any rule promulgated by the Board, any order of the

Department or Council, or any condition of any permit issued by the Department pursuant to the Oklahoma Clean Air Act, and to whom the Department has served, no less than fifteen (15) days previously, a written notice of violation. The Department shall by conference, conciliation and persuasion provide the person a reasonable opportunity to eliminate such violations, but may, however, reduce the fifteen-day notice period as in the opinion of the Department may be necessary to render the order reasonably effectual.

B. Such order may require compliance immediately or within a specified time period or both. The order, notwithstanding any restriction contained in subsection A of this section, may also assess an administrative penalty for past violations occurring no more than five (5) years prior to the date the order is filed with the Department, and for each day or part of a day that such person fails to comply with the order.

C. Any order issued pursuant to this section shall state with specificity the nature of the violation or violations, and may impose such requirements, procedures or conditions as may be necessary to correct the violations. The Department may also order any environmental contamination having the potential to adversely affect the public health, when caused by the violations, to be corrected by the person or persons responsible.

D. Any penalty assessed in the order shall not exceed Ten Thousand Dollars ($10,000.00) per day for each violation. In assessing such penalties, the Department shall consider the seriousness of the violation or violations, any good faith efforts to comply, and other factors determined by rule to be relevant. A final order following an enforcement hearing may assess an administrative penalty of an amount based upon consideration of the evidence but not exceeding the amount stated in the written order.

E. Any order issued pursuant to this section shall become a final order, unless no later than fifteen (15) days after the order is served the person or persons named therein request in writing an enforcement hearing. Said order shall contain language to that effect. Upon such request, the Department shall promptly schedule the enforcement hearing before an Administrative Law Judge for the Department and notify the respondent .

F. At all proceedings with respect to any alleged violation of the Oklahoma Clean Air Act, or any rule promulgated thereunder, the burden of proof shall be upon the Department.

G. Nothing in this section shall be construed to limit the authority of the Department to enter into an agreed settlement or consent order with any respondent.

Added by Laws 1992, HB 2251, c. 215, § 10, emerg. eff. May 15, 1992; Amended by Laws 1993, HB 1002, c. 145, § 47, emerg. eff. July 1, 1993; Renumbered from 63 O.S. § 1-1811 by Laws 1993, HB 1002, c. 145, § 359, emerg. eff. July 1, 1993; Amended by Laws 1993, SB 361, c. 324, § 13, emerg. eff. July 1, 1993; Amended by Laws 1999, HB 1781, c. 131, § 1, eff. November 1, 1999; Amended by Laws 2001, SB 199, c. 109, § 1, emerg. eff. April 18, 2001.

Title 27A. Environment and Natural Resources
Chapter 2 - Oklahoma Environmental Quality Code
Article V - Oklahoma Clean Air Act
Section 2-5-112 - Implementation of Comprehensive Permitting Program

27A O.S. § 2-5-112:

A. Upon the effective date of permitting rules promulgated pursuant to the Oklahoma Clean Air Act, it shall be unlawful for any person to construct any new source, or to modify or operate any new or existing source of emission of air contaminants except in compliance with a permit issued by the Department of Environmental Quality, unless the source has been exempted or deferred or is in compliance with an applicable deadline for submission of an application for such permit.

B. The Department shall have the authority and the responsibility, in accordance with rules of the Environmental Quality Board, to implement a comprehensive permitting program for the state consistent with the requirements of the Oklahoma Clean Air Act. Such authority shall include but shall not be limited to the authority to:

1. Expeditiously issue, reissue, modify and reopen for cause, permits for new and existing sources for the emission of air contaminants, and to grant a reasonable measure of priority to the processing of applications for new construction or modifications. The Department may also revoke, suspend, deny, refuse to issue or to reissue a permit upon a determination that any permittee or applicant is in violation of any substantive provisions of the Oklahoma Clean Air Act, or any rule promulgated thereunder or any permit issued pursuant thereto;

2. Refrain from issuing a permit when issuance has been objected to by the Environmental Protection Agency in accordance with Title V of the Federal Clean Air Act;

3. Revise any permit for cause or automatically reopen it to incorporate newly applicable rules or requirements if the remaining permit term is greater than three (3) years; or incorporate insignificant changes into a permit without requiring a revision;

4. Establish and enforce reasonable permit conditions which may include, but not be limited to:

a. emission limitations for regulated air contaminants,

b. operating procedures when related to emissions,

c. performance standards,

d. provisions relating to entry and inspections, and

e. compliance plans and schedules;

5. Require, if necessary, at the expense of the permittee or applicant:

a. installation and utilization of continuous monitoring devices,

b. sampling, testing and monitoring of emissions as needed to determine compliance,

c. submission of reports and test results, and

d. ambient air modeling and monitoring;

Added by Laws 1992, HB 2251, c. 215, § 12, emerg. eff. May 15, 1992; Amended by Laws 1993, HB 1002, c. 145, § 49, emerg. eff. July 1, 1993; Renumbered from 63 O.S. § 1-1813 by Laws 1993, HB 1002, c. 145, § 359, emerg. eff. July 1, 1993; Amended by Laws 1994, SB 997, c. 373, § 16, emerg. eff. July 1, 1994; Amended by Laws 1995, SB 247, c. 285, § 2, emerg. eff. July 1, 1996; Amended by Laws 1999, SB 417, c. 284, § 1, emerg. eff. May 27, 1999; Amended by Laws 1999, HB 1781, c. 131, § 2, eff. November 1, 1999 (repealed by Laws 2000, HB 2711, c. 6, § 33, emerg. eff. March 20, 2000); Amended by Laws 2000, HB 2711, c. 6, § 7, emerg. eff. March 20, 2000; Amended by Laws 2004, HB 1876, c. 83, § 1, emerg. eff. April 13, 2004; Amended by Laws 2004, HB 2198, c. 381, § 4, emerg. eff. June 3, 2004.

Title 27A. Environment and Natural Resources
Chapter 2 - Oklahoma Environmental Quality Code
Article V - Oklahoma Clean Air Act
Section 2-5-114 – Establishment of Program for Implementation and Enforcement of Federal Emission Standards

27A O.S. § 2-5-114:

A. The Department shall have the authority to establish a program for the implementation and enforcement of the federal emission standards and other requirements under Section 112 of the Federal Clean Air Act for hazardous air pollutants and for the prevention and mitigation of accidental releases of regulated substances under Section 112(r) of the Federal Clean Air Act.

1. Except as otherwise provided by paragraph 2 of this subsection, to assure that such program shall be consistent with, and not more stringent than, federal requirements:

a. any rule recommended by the Council and promulgated by the Board regarding hazardous air pollutants and regulated substances shall only be by adoption by reference of final federal rules, and

b. shall include the federal early reduction program under Section 112(i) (5) of the Federal Clean Air Act.

2. The Board may promulgate, pursuant to recommendation by the Council, rules which establish emission limitations for hazardous air pollutants which are more stringent than the applicable federal standards, upon a determination by the Council that more stringent standards are necessary to protect the public health or the environment.

B. The Department shall also have the authority to establish a separate and distinct program only for the control of the emission of those toxic air contaminants not otherwise regulated by a final emission standard under Section 112(d) of the Federal Clean Air Act.

1. Such program shall consist of permanent rules establishing:

a. appropriate emission limitations, work practice standards, maximum acceptable ambient concentrations or control technology standards necessary for the protection of the public health or the environment, and

b. emissions monitoring or process monitoring requirements necessary to assure compliance with the requirements of this section.

2. Paragraph 1 of this subsection shall not be construed as requiring readoption of existing rules regarding toxic air contaminants.

C. Regulation of any hazardous air pollutant pursuant to a final emission standard promulgated under Section 112(d) of the Federal Clean Air Act, shall preclude its regulation as a toxic air contaminant under subsection B of this section.

D. Emissions from any oil or gas exploration or production well with its associated equipment, and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources, and in the case of any oil or gas exploration or production well with its associated equipment, such emissions shall not be aggregated for any purpose under this section.

E. The Department shall not list oil and gas production wells with their associated equipment as an area source category, except that the Department may establish an area source category for oil and gas production wells located in any metropolitan statistical area or consolidated metropolitan statistical area with a population in excess of one million (1,000,000) if the Department determines that emissions of hazardous air pollutants from such wells present more than a negligible risk of adverse effects to public health.

F. Nothing in this section shall be construed to limit authority established elsewhere in the Oklahoma Clean Air Act.

Added by Laws 1992, HB 2251, c. 215, § 14, emerg. eff. May 15, 1992; Amended by Laws 1993, HB 1002, c. 145, § 51, emerg. eff. July 1, 1993; Renumbered from 63 O.S. § 1-1815 by Laws 1993, HB 1002, c. 145, § 359, emerg. eff. July 1, 1993.

Title 27A. Environment and Natural Resources
Chapter 2 - Oklahoma Environmental Quality Code
Article V - Oklahoma Clean Air Act
Section 2-5-117 – Authority to Commence Civil Actions

27A O.S. § 2-5-117:

A. The Department shall have the authority to commence a civil action for a permanent or temporary injunction or other appropriate relief, or to require abatement of any emission or correction of any contamination, or to seek and recover a civil penalty of not more than Ten Thousand Dollars ($10,000.00) per day for each violation, or all of the above, in any of the following instances:

1. Whenever any person has violated or is in violation of any applicable provision of the Oklahoma Clean Air Act, or any rule promulgated thereunder;

2. Whenever any person has commenced construction, modification or operation of any source, or operates any source in violation of the requirement to have a permit, or violates or is in violation of any substantive provision or condition of any permit issued pursuant to the Oklahoma Clean Air Act; or

3. Whenever any person has violated any order of the Department or the Council or any requirement to pay any fee, fine or penalty owed to the state pursuant to the Oklahoma Clean Air Act.

B. The district attorney or attorneys having jurisdiction shall have primary authority and responsibility for prosecution of any civil or criminal violations under the Oklahoma Clean Air Act and for the collection of any delinquent fees, penalties or fines assessed pursuant to the Oklahoma Clean Air Act and shall be entitled to recover reasonable costs of collection, including attorney fees, and an appropriate fee of up to fifty percent (50%) for collecting delinquent fees, penalties or fines.

Added by Laws 1992, HB 2251, c. 215, § 17, emerg. eff. May 15, 1992. Amended by Laws 1993, HB 1002, c. 145, § 54, emerg. eff. July 1, 1993; Renumbered from 63 O.S. § 1-1818 by Laws 1993, HB 1002, c. 145, § 359, emerg. eff. July 1, 1993.

Title 51. Officers
Chapter 1 – General Provisions
Oklahoma Open Records Act
Section 24A.1 – Short Title

51 O.S. § 24A.1:

Section 24A.1 et seq. of this title shall be known and may be cited as the "Oklahoma Open Records Act"

Added by Laws 1985, SB 276, c. 355, § 1, eff. November 1, 1985; Amended by Laws 1988, HB 1803, c. 68, § 1, eff. November 1, 1988; Amended by Laws 1988, HB 1846, c. 187, § 1, emerg. eff. June 6, 1988; Amended by Laws 1996, HB 2692, c. 247, § 41, emerg. eff. July 1, 1996; Amended by Laws 1997, HB 1436, c. 2, § 10, emerg. eff. February 26, 1997.

Title 51. Officers
Chapter 1 – General Provisions
Oklahoma Open Records Act
Section 24A.2 – Political Power – Public Policy and Purpose of Act

51 O.S. § 24A.2:

As the Oklahoma Constitution recognizes and guarantees, all political power is inherent in the people. Thus, it is the public policy of the State of Oklahoma that the people are vested with the inherent right to know and be fully informed about their government. The Oklahoma Open Records Act shall not create, directly or indirectly, any rights of privacy or any remedies for violation of any rights of privacy; nor shall the Oklahoma Open Records Act, except as specifically set forth in the Oklahoma Open Records Act, establish any procedures for protecting any person from release of information contained in public records. The purpose of this act is to ensure and facilitate the public's right of access to and review of government records so they may efficiently and intelligently exercise their inherent political power. The privacy interests of individuals are adequately protected in the specific exceptions to the Oklahoma Open Records Act or in the statutes which authorize, create or require the records. Except where specific state or federal statutes create a confidential privilege, persons who submit information to public bodies have no right to keep this information from public access nor reasonable expectation that this information will be kept from public access; provided, the person, agency or political subdivision shall at all times bear the burden of establishing such records are protected by such a confidential privilege. Except as may be required by other statutes, public bodies do not need to follow any procedures for providing access to public records except those specifically required by the Oklahoma Open Records Act.

Added by Laws 1985, SB 276, c. 355, § 2, eff. November 1, 1985; Amended by Laws 1988, HB 1846, c. 187, § 2, emerg. eff. June 6, 1988.

Title 51. Officers
Chapter 1 – General Provisions
Oklahoma Open Records Act
Section 24A.3 – Definitions

51 O.S. § 24A.3:

As used in this act:

1. "Record" means all documents, including, but not limited to, any book, paper, photograph, microfilm, data files created by or used with computer software, computer tape, disk, record, sound recording, film recording, video record or other material regardless of physical form or characteristic, created by, received by, under the authority of, or coming into the custody, control or possession of public officials, public bodies, or their representatives in connection with the transaction of public business, the expenditure of public funds or the administering of public property. "Record" does not mean:

a. computer software,

b. nongovernment personal effects,

c. unless public disclosure is required by other laws or regulations, vehicle movement records of the Oklahoma Transportation Authority obtained in connection with the Authority's electronic toll collection system,

d. personal financial information, credit reports or other financial data obtained by or submitted to a public body for the purpose of evaluating credit worthiness, obtaining a license, permit, or for the purpose of becoming qualified to contract with a public body,

e. any digital audio/video recordings of the toll collection and safeguarding activities of the Oklahoma Transportation Authority,

f. any personal information provided by a guest at any facility owned or operated by the Oklahoma Tourism and Recreation Department or the Board of Trustees of the Quartz Mountain Arts and Conference Center and Nature Park to obtain any service at the facility or by a purchaser of a product sold by or through the Oklahoma Tourism and Recreation Department or the Quartz Mountain Arts and Conference Center and Nature Park,

g. a Department of Defense Form 214 (DD Form 214) filed with a county clerk, including any DD Form 214 filed before the effective date of this act, or

h. except as provided for in Section 2-110 of Title 47 of the Oklahoma Statutes,

(1) any record in connection with a Motor Vehicle Report issued by the Department of Public Safety, as prescribed in Section 6-117 of Title 47 of the Oklahoma Statutes,

(2) personal information within driver records, as defined by the Driver's Privacy Protection Act, 18 United States Code, Sections 2721 through 2725, which are stored and maintained by the Department of Public Safety, or

(3) audio or video recordings of the Department of Public Safety;

2. "Public body" shall include, but not be limited to, any office, department, board, bureau, commission, agency, trusteeship, authority, council, committee, trust or any entity created by a trust, county, city, village, town, township, district, school district, fair board, court, executive office, advisory group, task force, study group, or any subdivision thereof, supported in whole or in part by public funds or entrusted with the expenditure of public funds or administering or operating public property, and all committees, or subcommittees thereof. Except for the records required by Section 24A.4 of this title, "public body" does not mean judges, justices, the Council on Judicial Complaints, the Legislature, or legislators;

3. "Public office" means the physical location where public bodies conduct business or keep records;

4. "Public official" means any official or employee of any public body as defined herein; and

5. "Law enforcement agency" means any public body charged with enforcing state or local criminal laws and initiating criminal prosecutions, including, but not limited to, police departments, county sheriffs, the Department of Public Safety, the Oklahoma State Bureau of Narcotics and Dangerous Drugs Control, the Alcoholic Beverage Laws Enforcement Commission, and the Oklahoma State Bureau of Investigation.

Added by Laws 1985, SB 276, c. 355, § 3, eff. November 1, 1985; Amended by Laws 1987, HB 1444, c. 222, § 117, emerg. eff. July 1, 1987; Amended by Laws 1988, HB 1846, c. 187, § 3, emerg. eff. June 6, 1988; Amended by Laws 1993, HB 1471, c. 39, § 1, eff. September 1, 1993; Amended by Laws 1996, SB 719, c. 209, § 2, eff. November 1, 1996; Amended by Laws 1998, SB 996, c. 315, § 4, emerg. eff. May 28, 1998; Amended by Laws 1998, HB 3063, c. 368, § 11, emerg. eff. July 1, 1998; Amended by Laws 2001, SB 748, c. 355, § 1, emerg. eff. June 1, 2001; Amended by Laws 2002, HB 2738, c. 293, § 3, emerg. eff. May 22, 2002 (repealed by Laws 2003, HB 1816, c. 3, § 43, emerg. eff. March 19, 2003); Amended by SB 960, c. 478, § 2, emerg. eff. July 1, 2002; Amended by Laws 2003, HB 1816, c. 3, § 42, emerg. eff. March 19, 2003; Amended by Laws 2004, HB 1695, c. 328, § 1, emerg. eff. July 1, 2004; Amended by Laws 2005, HB 1553, c. 199, § 4, eff. November 1, 2005.

Title 51. Officers
Chapter 1 – General Provisions
Oklahoma Open Records Act
Section 24A.4 – Duty to Keep and Maintain Complete Records of Receipt and Expenditure of Funds

51 O.S. § 24A.4:

In addition to other records which are kept or maintained, every public body and public official has a specific duty to keep and maintain complete records of the receipt and expenditure of any public funds reflecting all financial and business transactions relating thereto, except that such records may be disposed of as provided by law.

Added by Laws 1985, SB 276, c. 355, § 4, eff. November 1, 1985.

Title 51. Officers
Chapter 1 – General Provisions
Oklahoma Open Records Act
Section 24A.5 – Open and Confidential Records

51 O.S. § 24A.5:

All records of public bodies and public officials shall be open to any person for inspection, copying, or mechanical reproduction during regular business hours; provided:

1. The Oklahoma Open Records Act, Sections 24A.1 through 24A.28 of this title, does not apply to records specifically required by law to be kept confidential including:

a. records protected by a state evidentiary privilege such as the attorney-client privilege, the work product immunity from discovery and the identity of informer privileges,

b. records of what transpired during meetings of a public body lawfully closed to the public such as executive sessions authorized under the Oklahoma Open Meeting Act, Section 301 et seq. of Title 25 of the Oklahoma Statutes,

c. personal information within driver records as defined by the Driver's Privacy Protection Act, 18 United States Code, Sections 2721 through 2725, or

d. information in the files of the Board of Medicolegal Investigations obtained pursuant to Sections 940 and 941 of Title 63 of the Oklahoma Statutes that may be hearsay, preliminary unsubstantiated investigation-related findings, or confidential medical information.

2. Any reasonably segregable portion of a record containing exempt material shall be provided after deletion of the exempt portions; provided however, the Department of Public Safety shall not be required to assemble for the requesting person specific information, in any format, from driving records relating to any person whose name and date of birth or whose driver license number is not furnished by the requesting person.

The Oklahoma State Bureau of Investigation shall not be required to assemble for the requesting person any criminal history records relating to persons whose names, dates of birth, and other identifying information required by the Oklahoma State Bureau of Investigation pursuant to administrative rule are not furnished by the requesting person.

3. Any request for a record which contains individual records of persons, and the cost of copying, reproducing or certifying each individual record is otherwise prescribed by state law, the cost may be assessed for each individual record, or portion thereof requested as prescribed by state law. Otherwise, a public body may charge a fee only for recovery of the reasonable, direct costs of record copying, or mechanical reproduction. Notwithstanding any state or local provision to the contrary, in no instance shall the record copying fee exceed twenty-five cents ($0.25) per page for records having the dimensions of eight and one-half (8 1/2) by fourteen (14) inches or smaller, or a maximum of One Dollar ($1.00) per copied page for a certified copy. However, if the request:

a. is solely for commercial purpose, or

b. would clearly cause excessive disruption of the essential functions of the public body,

then the public body may charge a reasonable fee to recover the direct cost of record search and copying; however, publication in a newspaper or broadcast by news media for news purposes shall not constitute a resale or use of a record for trade or commercial purpose and charges for providing copies of electronic data to the news media for a news purpose shall not exceed the direct cost of making the copy. The fee charged by the Department of Public Safety for a copy in a computerized format of a record of the Department shall not exceed the direct cost of making the copy unless the fee for the record is otherwise set by law.

Any public body establishing fees under this act shall post a written schedule of the fees at its principal office and with the county clerk.

In no case shall a search fee be charged when the release of records is in the public interest, including, but not limited to, release to the news media, scholars, authors and taxpayers seeking to determine whether those entrusted with the affairs of the government are honestly, faithfully, and competently performing their duties as public servants.

The fees shall not be used for the purpose of discouraging requests for information or as obstacles to disclosure of requested information.

4. The land description tract index of all recorded instruments concerning real property required to be kept by the county clerk of any county shall be available for inspection or copying in

accordance with the provisions of the Oklahoma Open Records Act; provided, however, the index shall not be copied or mechanically reproduced for the purpose of sale of the information.

5. A public body must provide prompt, reasonable access to its records but may establish reasonable procedures which protect the integrity and organization of its records and to prevent excessive disruptions of its essential functions.

6. A public body shall designate certain persons who are authorized to release records of the public body for inspection, copying, or mechanical reproduction. At least one person shall be available at all times to release records during the regular business hours of the public body.

Added by Laws 1985, SB 276, c. 355, § 5, eff. November 1, 1985; Amended by Laws 1986, SB 487, c. 213, § 1, emerg. eff. June 6, 1986; Amended by Laws 1986, HB 1633, c. 279, § 29, emerg. eff. July 1, 1986; Amended by Laws 1988, HB 1846, c. 187, § 4, emerg. eff. June 6, 1988; Amended by Laws 1992, HB 2142, c. 231, § 2, emerg. eff. May 19, 1992; Amended by Laws 1993, HB 1053, c. 97, § 7, eff. September 1, 1993; Amended by Laws 1996, SB 719, c. 209, § 3, eff. November 1, 1996; Amended by Laws 2000, HB 2100, c. 342, § 8, emerg. eff. July 1, 2000; Amended by Laws 2001, SB 665, c. 137, § 1, emerg. eff. April 24, 2001; Amended by Laws 2005, HB 1553, c. 199, § 5, eff. November 1, 2005; Amended by Laws 2005, HB 1318, c. 223, § 1, eff. November 1, 2005 (repealed by Laws 2006, HB 3139, c. 16, § 35, emerg. eff. March 29, 2006); Amended by Laws 2006, HB 3139, c. 16, § 34, emerg. eff. March 29, 2006.

Title 51. Officers
Chapter 1 – General Provisions
Oklahoma Open Records Act
Section 24A.6 – Written Notice of Business Hours of Public Bodies - Inspection, Copying, or Reproduction of Records of Public Body

51 O.S. § 24A.6:

A. If a public body or its office does not have regular business hours of at least thirty (30) hours a week, the public body shall post and maintain a written notice at its principal office and with the county clerk where the public body is located which notice shall:

1. Designate the days of the week when records are available for inspection, copying or mechanical reproduction;

2. Set forth the name, mailing address, and telephone number of the individual in charge of the records; and

3. Describe in detail the procedures for obtaining access to the records at least two days of the week, excluding Sunday.

B. The person requesting the record and the person authorized to release the records of the public body may agree to inspection, copying, or mechanical reproduction on a day and at a time other than that designated in the notice.

Added by Laws 1985, SB 276, c. 355, § 6, eff. November 1, 1985.

Title 51. Officers
Chapter 1 – General Provisions
Oklahoma Open Records Act
Section 24A.7 – Confidential Personnel Records of Public Body

51 O.S. § 24A.7:

A. A public body may keep personnel records confidential:

1. Which relate to internal personnel investigations including examination and selection material for employment, hiring, appointment, promotion, demotion, discipline, or resignation; or

2. Where disclosure would constitute a clearly unwarranted invasion of personal privacy such as employee evaluations, payroll deductions, employment applications submitted by persons not hired by the public body, and transcripts from institutions of higher education maintained in the personnel files of certified public school employees; provided, however, that nothing in this subsection shall be construed to exempt from disclosure the degree obtained and the curriculum on the transcripts of certified public school employees.

B. All personnel records not specifically falling within the exceptions provided in subsection A of this section shall be available for public inspection and copying including, but not limited to, records of:

1. An employment application of a person who becomes a public official;

2. The gross receipts of public funds;

3. The dates of employment, title or position; and

4. Any final disciplinary action resulting in loss of pay, suspension, demotion of position, or termination.

C. Except as may otherwise be made confidential by statute, an employee of a public body shall have a right of access to his own personnel file.

D. Public bodies shall keep confidential the home address, telephone numbers and social security numbers of any person employed or formerly employed by the public body.

Added by Laws 1985, SB 276, c. 355, § 7, eff. November 1, 1985; Amended by Laws 1990, HB 1883, c. 257, § 6, emerg. eff. May 23, 1990; Amended by Laws 1994, HB 2268, c. 177, § 1, eff. September 1, 1994; Amended by Laws 2005, HB 1728, c. 116, § 2, eff. November 1, 2005.

Title 51. Officers
Chapter 1 – General Provisions
Oklahoma Open Records Act
Section 24A.8 – Law Enforcement Agency Records Available for Public Inspection

51 O.S. § 24A.8:

1. An arrestee description, including the name, date of birth, address, race, sex, physical description, and occupation of the arrestee;

2. Facts concerning the arrest, including the cause of arrest and the name of the arresting officer;

3. A chronological list of all incidents, including initial offense report information showing the offense, date, time, general location, officer, and a brief summary of what occurred;

4. Radio logs, including a chronological listing of the calls dispatched;

5. Conviction information, including the name of any person convicted of a criminal offense;

6. Disposition of all warrants, including orders signed by a judge of any court commanding a law enforcement officer to arrest a particular person;

7. A crime summary, including an agency summary of crimes reported and public calls for service by classification or nature and number; and

8. Jail registers, including jail blotter data or jail booking information recorded on persons at the time of incarceration showing the name of each prisoner with the date and cause of commitment, the authority committing the prisoner, whether committed for a criminal offense, a description of the prisoner, and the date or manner of discharge or escape of the prisoner.

B. Except for the records listed in subsection A of this section and those made open by other state or local laws, law enforcement agencies may deny access to law enforcement records except where a court finds that the public interest or the interest of an individual outweighs the reason for denial.

C. Nothing contained in this section imposes any new recordkeeping requirements. Law enforcement records shall be kept for as long as is now or may hereafter be specified by law. Absent a legal requirement for the keeping of a law enforcement record for a specific time period, law enforcement agencies shall maintain their records for so long as needed for administrative purposes.

D. Registration files maintained by the Department of Corrections pursuant to the provisions of the Sex Offenders Registration Act shall be made available for public inspection in a manner to be determined by the Department.

E. The Council on Law Enforcement Education and Training (C.L.E.E.T.) shall keep confidential all records it maintains pursuant to Section 3311 of Title 70 of the Oklahoma Statutes and deny release of records relating to any employed or certified full-time officer, reserve officer, retired officer or other person; teacher lesson plans, tests and other teaching materials; and personal communications concerning individual students except under the following circumstances:

1. To verify the current certification status of any peace officer;

2. As may be required to perform the duties imposed by Section 3311 of Title 70 of the Oklahoma Statutes;

3. To provide to any peace officer copies of the records of that peace officer upon submitting a written request;

4. To provide, upon written request, to any law enforcement agency conducting an official investigation, copies of the records of any peace officer who is the subject of such investigation;

5. To provide final orders of administrative proceedings where an adverse action was taken against a peace officer; and

6. Pursuant to an order of the district court of the State of Oklahoma.

F. The Department of Public Safety shall keep confidential:

1. All records it maintains pursuant to its authority under Title 47 of the Oklahoma Statutes relating to the Oklahoma Highway Patrol Division, the Communications Division, and other divisions of the Department relating to:

a. training, lesson plans, teaching materials, tests, and test results,

b. policies, procedures, and operations, any of which are of a tactical nature, and

c. the following information from radio logs:

(1) telephone numbers,

(2) addresses other than the location of incidents to which officers are dispatched, and

(3) personal information which is contrary to the provisions of the Driver's Privacy Protection Act, 18 United States Code, Sections 2721 through 2725; and

2. For the purpose of preventing identity theft and invasion of law enforcement computer systems, except as provided in Title 47 of the Oklahoma Statutes, all driving records.

Added by Laws 1985, SB 276, c. 355, § 8, eff. November 1, 1985; Amended by Laws 1989, HB 1136, c. 212, § 8, eff. November 1, 1989; Amended by Laws 2000, HB 2428, c. 226, § 1, eff. November 1, 2000 (repealed by Laws 2001, HB 1965, c. 5, § 30, emerg. eff. March 21, 2001) ; Amended by Laws 2000, HB 2552, c. 349, § 2, eff. November 1, 2000; Amended by Laws 2001, HB 1965, c. 5, § 29, emerg. eff. March 21, 2001; Amended by Laws 2005, SB 13, c. 35, § 1, emerg. eff. April 12, 2005 (repealed by Laws 2006, HB 3139, c. 16, § 37, emerg. eff. March 29, 2006); Amended by Laws 2005, HB 1553, c. 199, § 6, eff. November 1, 2005; Amended by Laws 2006, HB 3139, c. 16, § 36, emerg. eff. March 29, 2006; Amended by Laws 2009, HB 1049, c. 36, § 1, eff. November 1, 2009.

Title 51. Officers
Chapter 1 – General Provisions
Oklahoma Open Records Act
Section 24A.9 – Confidential Personal Notes and Personally Created Materials of Public Official Making Recommendation

51 O.S. § 24A.9:

Prior to taking action, including making a recommendation or issuing a report, a public official may keep confidential his or her personal notes and personally created materials other than departmental budget requests of a public body prepared as an aid to memory or research leading to the adoption of a public policy or the implementation of a public project.

Added by Laws 1985, SB 276, c. 355, § 9, eff. November 1, 1985.

Title 51. Officers
Chapter 1 – General Provisions
Oklahoma Open Records Act
Section 24A.10 – Disclosure of Information Voluntarily Supplied

51 O.S. § 24A.10:

A. Any information, records or other material heretofore voluntarily supplied to any state agency, board or commission which was not required to be considered by that agency, board or commission in the performance of its duties may, within thirty (30) days from June 6, 1988, be removed from the files of such agency, board or commission by the person or entity which originally voluntarily supplied such information. Provided, after thirty (30) days from the effective date of this act, any information voluntarily supplied shall be subject to full disclosure pursuant to this act.

B. If disclosure would give an unfair advantage to competitors or bidders, a public body may keep confidential records relating to:

1. Bid specifications for competitive bidding prior to publication by the public body; or

2. Contents of sealed bids prior to the opening of bids by a public body; or

3. Computer programs or software but not data thereon; or

4. Appraisals relating to the sale or acquisition of real estate by a public body prior to award of a contract; or

5. The prospective location of a private business or industry prior to public disclosure of such prospect except for records otherwise open to inspection such as applications for permits or licenses.

C. Except as set forth hereafter, the Oklahoma Department of Commerce, the Oklahoma Department of Career and Technology Education, the technology center school districts, and the Oklahoma Film and Music Office may keep confidential:

1. Business plans, feasibility studies, financing proposals, marketing plans, financial statements or trade secrets submitted by a person or entity seeking economic advice, business development or customized training from such Departments or school districts;

2. Proprietary information of the business submitted to the Department or school districts for the purpose of business development or customized training, and related confidentiality agreements detailing the information or records designated as confidential; and

3. Information compiled by such Departments or school districts in response to those submissions.

The Oklahoma Department of Commerce, the Oklahoma Department of Career and Technology Education, the technology center school districts, and the Oklahoma Film and Music Office may not keep confidential that submitted information when and to the extent the person or entity submitting the information consents to disclosure.

D. Although they must provide public access to their records, including records of the address, rate paid for services, charges, consumption rates, adjustments to the bill, reasons for adjustment, the name of the person that authorized the adjustment, and payment for each customer, public bodies that provide utility services to the public may keep confidential credit information, credit card numbers, telephone numbers, social security numbers, bank account information for individual customers, and utility supply and utility equipment supply contracts for any industrial customer with a connected electric load in excess of two thousand five hundred (2,500) kilowatts if public access to such contracts would give an unfair advantage to competitors of the customer; provided that, where a public body performs billing or collection services for a utility regulated by the Corporation Commission pursuant to a contractual agreement, any customer or individual payment data obtained or created by the public body in performance of the agreement shall not be a record for purposes of this act.

Added by Laws 1985, SB 276, c. 355, § 10, eff. November 1, 1985; Amended by Laws 1988, HB 1846, c. 187, § 5, emerg. eff. June 6, 1988; Amended by Laws 1996, SB 719, c. 209, § 4, eff. November 1, 1996; Amended by Laws 2004, SB 1108, c. 186, § 1, emerg. eff. May 3, 2004; Amended by Laws 2006, HB 2396, c. 18, § 1, eff. November 1, 2006; Amended by Laws 2007, HB 1038, c. 6, § 1, eff. November 1, 2007; Amended by Laws 2008, HB 2250, c. 284, § 1, eff. November 1, 2008; Amended by Laws 2009, SB 285, c. 158, § 1, eff. November 1, 2009; Amended by Laws 2010, SB 1351, c. 161, § 1.

Title 51. Officers
Chapter 1 – General Provisions
Oklahoma Open Records Act
Section 24A.13 – Confidential Federal Legislation Records

51 O.S. § 24A.13:

Records coming into the possession of a public body from the federal government or records generated or gathered as a result of federal legislation may be kept confidential to the extent required by federal law.

Added by Laws 1985, SB 276, c. 355, § 13, eff. November 1, 1985.

Title 51. Officers
Chapter 1 – General Provisions
Oklahoma Open Records Act
Section 24A.14 – Confidential Personal Communications Exercising Constitutional Rights

51 O.S. § 24A.14:

Except for the fact that a communication has been received and that it is or is not a complaint, a public official may keep confidential personal communications received by the public official from a person exercising rights secured by the Constitution of the State of Oklahoma or the Constitution of the United States. The public official's written response to this personal communication may be kept confidential only to the extent necessary to protect the identity of the person exercising the right.

Added by Laws 1985, SB 276, c. 355, § 14, eff. November 1, 1985.

Title 51. Officers
Chapter 1 – General Provisions
Oklahoma Open Records Act
Section 24A.17 – Violations of Oklahoma Open Records Act – Civil Liability

51 O.S. § 24A.17:

A. Any public official who willfully violates any provision of the Oklahoma Open Records Act, upon conviction, shall be guilty of a misdemeanor, and shall be punished by a fine not exceeding Five Hundred Dollars ($500.00) or by imprisonment in the county jail for a period not exceeding one (1) year, or by both such fine and imprisonment.

B. Any person denied access to records of a public body or public official:

1. May bring a civil suit for declarative or injunctive relief, or both, but such civil suit shall be limited to records requested and denied prior to filing of the civil suit; and

2. If successful, shall be entitled to reasonable attorney fees.

C. If the public body or public official successfully defends a civil suit and the court finds that the suit was clearly frivolous, the public body or public official shall be entitled to reasonable attorney fees.

D. A public body or public official shall not be civilly liable for damages for providing access to records as allowed under the Oklahoma Open Records Act.

Added by Laws 1985, SB 276, c. 355, § 17, eff. November 1, 1985; Amended by Laws 2005, HB 1553, c. 199, § 7, eff. November 1, 2005.

Title 51. Officers
Chapter 1 – General Provisions
Oklahoma Open Records Act
Section 24A.18 – Additional Recordkeeping Requirements on Public Bodies or Public Officials not Imposed

51 O.S. § 24A.18:

Except as may be required in Section 24A.4 of this title, this act does not impose any additional recordkeeping requirements on public bodies or public officials.

Added by Laws 1985, SB 276, c. 355, § 18, eff. November 1, 1985; Amended by Laws 2005, HB 1553, c. 199, § 8, eff. November 1, 2005.

Title 51. Officers
Chapter 1 – General Provisions
Oklahoma Open Records Act
Section 24A.20 – Access to Records in Possession of Public Body or Official for Investigatory Purposes

51 O.S. § 24A.20:

Access to records which, under the Oklahoma Open Records Act, would otherwise be available for public inspection and copying, shall not be denied because a public body or public official is using or has taken possession of such records for investigatory purposes or has placed the records in a litigation or investigation file. However, a law enforcement agency may deny access to a copy of such a record in an investigative file if the record or a true and complete copy thereof is available for public inspection and copying at another public body.

Added by Laws 1988, HB 1846, c. 187, § 7, emerg. eff. June 6, 1988.

Title 51. Officers
Chapter 1 – General Provisions
Oklahoma Open Records Act
Section 24A.21 – Fees Charged State Agency or Taxing Entity

51 O.S. § 24A.21:

The fees that may be charged by a public body pursuant to the provisions of paragraph 3 of Section 24A.5 of Title 51 of the Oklahoma Statutes shall not be charged when a state agency or taxing entity located within the boundaries of any district created pursuant to the provisions of the Local Development Act request a copy of the reports required by subsections A and B of Section 18 of this act.

Added by Laws 1992, HB 1525, c. 342, § 21, emerg. eff. July 1, 1992.

Title 51. Officers
Chapter 1 – General Provisions
Oklahoma Open Records Act
Section 24A.25 – Removal of Materials from the Public Record

51 O.S. § 24A.25:

Any order of the court for removal of materials from the public record shall require compliance with the provisions of paragraphs 2 through 7 of subsection C of Section 3226 of Title 12 of the Oklahoma Statutes.

Added by Laws 2000, SB 1329, c. 172, § 4, eff. November 1, 2000.

Title 51. Officers
Chapter 1 – General Provisions
Oklahoma Open Records Act
Section 24A.26 – Intergovernmental Self-Insurance Pools

51 O.S. § 24A.26:

An intergovernmental self-insurance pool may keep confidential proprietary information, such as actuarial reports, underwriting calculations, rating information and records that are created based on conclusions of such information that are developed through the operation of the intergovernmental self-insurance pool.

Added by Laws 2000, HB 2428, c. 226, § 2, eff. November 1, 2000.

Title 51. Officers
Chapter 1 – General Provisions
Oklahoma Open Records Act
Section 24A.27 – Confidentiality Vulnerability Assessments

51 O.S. § 24A.27:

A. Any state environmental agency or public utility shall keep confidential vulnerability assessments of critical assets in both water and wastewater systems. State environmental agencies or public utilities may use the information for internal purposes or allow the information to be used for survey purposes only. The state environmental agencies or public utilities shall allow any public body to have access to the information for purposes specifically related to the public bodies function.

B. For purposes of this section:

1. "State environmental agencies" includes the:

a. Oklahoma Water Resources Board,

b. Oklahoma Corporation Commission,

c. State Department of Agriculture,

d. Oklahoma Conservation Commission,

e. Department of Wildlife Conservation,

f. Department of Mines, and

g. Department of Environmental Quality;

2. "Public Utility" means any individual, firm, association, partnership, corporation or any combination thereof, municipal corporations or their lessees, trustees and receivers, owning or operating for compensation in this state equipment or facilities for:

a. producing, generating, transmitting, distributing, selling or furnishing electricity,

b. the conveyance, transmission, reception or communications over a telephone system,

c. transmitting directly or indirectly or distributing combustible hydrocarbon natural or synthetic natural gas for sale to the public, or

d. the transportation, delivery or furnishing of water for domestic purposes or for power.

Added by Laws 2003, HB 1146, c. 166, § 1, emerg. eff. May 5, 2003.

Oklahoma Administrative Rules:

TITLE 252. DEPARTMENT OF ENVIRONMENTAL QUALITY
CHAPTER 4. RULES OF PRACTICE AND PROCEDURE

252:4-1-3. Organization
(a) **Environmental Quality Board.** The Environmental Quality Board consists of thirteen (13) members, appointed by the Governor with the advice and consent of the Senate, selected from the environmental profession, general industry, hazardous waste industry, solid waste industry, water usage, petroleum industries, agriculture industries, conservation districts, local city or town governments, rural water districts, and statewide nonprofit environmental organizations. (See further 27A O.S. § 2-2-101.)
(b) **Advisory Councils.** There are seven advisory councils, each consisting of nine (9) members appointed by the Speaker of the House of Representatives, the President Pro Tempore of the Senate or the Governor. (See further 27A O.S. § 2-2-201 and 59 O.S. § 1101 *et seq*.)
(c) **DEQ.** The DEQ consists of the following divisions: Administrative Services, Air Quality, Land Protection, Water Quality, Environmental Complaints and Local Services, Customer Services and the State Environmental Laboratory.

Effective date – June 11, 2001

Mary Fallin
Governor

March 30, 2011

Dr. Alfredo Armendariz, Regional Administrator (6RA)
U.S. Environmental Protection Agency – Region VI
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

Subject: Appointing Mr. Gary Sherrer as Designee for State Implementation Purposes

Dear Dr. Armendariz:

As Governor of the State of Oklahoma, I hereby designate the Oklahoma Secretary of Environment, Mr. Gary Sherrer, to serve as my designee for the purpose of submitting documents to the U.S. Environmental Protection Agency (EPA) for approval and incorporation into the State Implementation Plan (SIP) for the State of Oklahoma, pursuant to Section 110 of the Federal Clean Air Act and EPA's implementing regulation in 40 C.F.R. Section 51.

Secretary Shearer will serve as my designee until you receive further notification in writing from this office. If you have any questions, please contact this office.

Sincerely,

Mary Fallin

Mary Fallin

cc: Gary Sherrer, Secretary of Environment
Steve Thompson, Executive Director, Department of Environmental Quality

GARY L. SHERRER
SECRETARY OF ENVIRONMENT

MARY FALLIN
GOVERNOR

STATE OF OKLAHOMA

**OFFICE OF THE
SECRETARY OF ENVIRONMENT**
www.environment.ok.gov

March 20, 2013

Mr. Ron Curry, Regional Administrator (6RA)
U.S. Environmental Protection Agency – Region VI
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

Subject: Request for Parallel Processing of Proposed Oklahoma Regional Haze State Implementation Plan Revision

Dear Mr. Curry:

In a letter to your predecessor dated March 30, 2011, Governor Mary Fallin appointed me as her designee for the purpose of submitting documents to the U.S. Environmental Protection Agency (EPA) for approval and incorporation into the State Implementation Plan (SIP) for the State of Oklahoma. The Oklahoma Department of Environmental Quality (DEQ) is given the primary responsibility and authority to prepare and implement the state's air quality management plan under Oklahoma Statutes.

Accordingly, the State of Oklahoma submits for your review under Section 110 of the federal Clean Air Act and 40 CFR Part 51, a proposed revision of the Oklahoma Regional Haze State Implementation Plan submitted in February 2010, and the associated evidence as required by 40 CFR 51, Appendix V, 2.1. This revision of the Regional Haze SIP addresses EPA's regional haze regulations, 40 CFR § 51.308, as they relate to the BART determination for American Electric Power/Public Service Company of Oklahoma ("AEP/PSO") Northeastern Power Station Units 3 & 4. This revision implements relevant portions of a settlement agreement reached among EPA, the Oklahoma Secretary of Environment, DEQ, U.S. Department of Justice, AEP/PSO and the Sierra Club, and is intended to replace the related EPA-issued Federal Implementation Plan (FIP), *see* 76 Fed.Reg. 81727 (Jan. 27, 2012), as it relates to the subject facility. The proposed SIP revision also includes revisions to affected portions of the Interstate Transport SIP for the 1997 8-hour Ozone and 1997 $PM_{2.5}$ NAAQS, submitted in May 2007 (including supplemental information submitted in November 2007), and is intended to replace the related EPA-issued FIP as it relates to the subject facility.

We are requesting parallel processing of this submittal in accordance with the settlement agreement and Janet McCabe's 10/31/2011 Memo (Subject: Options and Efficiency Tools for EPA Action on State Implementation Plan Submittals). DEQ has scheduled a public hearing regarding the SIP revision for May 20, 2013. DEQ has enclosed a draft notice of the public hearing and opportunity to comment on the proposed SIP revision, as required by 40 CFR § 51.102. Notice will be posted on DEQ's Regional Haze webpage by Tuesday, April 19, 2013, and provided via e-mails to those persons who have expressed an interest in SIP revisions and have supplied their e-mail addresses. Information on the Public Notice, the proposed revision,

Mr. Ron Curry
U.S. EPA – Region VI
March 20, 2013

and related documents will also be prominently displayed on DEQ's main Air Quality Division webpage. In addition, a notice will be published in at least one newspaper of general circulation at least 30 days before the hearing. The Review, Consultations and Comments Section of the proposed Regional Haze SIP Revision describes DEQ's plans for consultation and for receiving, posting, and responding to any comments received.

Simultaneous with this request, DEQ is providing electronic access to the proposed SIP revision and notification of a consultation opportunity to the designated Federal Land Manager (FLM) staff in accordance with the consultation provisions of 40 CFR § 51.308(i)(2), and to clean air agency staff for bordering/potentially affected states in accordance with 40 CFR § 51.308(d)(3)(i). Following evaluation of all comments received, Oklahoma will respond to comments and finalize and submit the Regional Haze SIP revision in accordance with EPA regulations and the referenced settlement agreement. As required by 40 CFR § 51.103(a) and regional guidance, we have included with this letter two paper copies and an identical electronic copy (on CD) of the submittal. The submittal is also currently available on the DEQ webpage set up for FLM's and States' access at:

http://www.deq.state.ok.us/aqdnew/RulesAndPlanning/Regional_Haze_rev2013

If you have questions, please contact me or Eddie Terrill, Director of DEQ's Air Quality Division, at (405) 702-4154.

Sincerely

Gary L. Sherrer

Gary Sherrer
Secretary of Environment

Enclosures

cc: Steve Thompson, Executive Director, Department of Environmental Quality
Eddie Terrill, Director, DEQ Air Quality Division
Guy Donaldson, Section Chief, Air Planning Section, EPA Region VI (6PD-L)
Jeff Robinson, Section Chief, Air Permits, EPA Region VI (6PD-R)

O K L A H O M A
DEPARTMENT OF ENVIRONMENTAL QUALITY

STEVEN A. THOMPSON
Executive Director

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

MARY FALLIN
Governor

August 17, 2012

Mr. Thomas Diggs, Associate Director for Air Programs (6PD)
U.S. Environmental Protection Agency – Region VI
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

Subject: Public Participation Procedures for Oklahoma SIP Review/Revision Submittals

Dear Mr. Diggs:

Oklahoma has traditionally complied with the public notice requirements of 40 CFR Part 51 for non-rule SIP components by using newspaper notice. In this letter, we are notifying you of our intention to use internet notice to provide this notification for these components. We have attached our public participation procedures, that include internet notice, for State Implementation Plan (SIP) Review/Revision submittals under 40 CFR Part 51, as provided for under 40 CFR §51.102(g). The procedures apply primarily to non-rule SIP components, since procedures for adopting agency rules are prescribed by statute and regulation. [For additional details see recently-approved Infrastructure Certification(s).]

These internet posting procedures would be used for all future SIP Reviews/Revisions submittals, including Oklahoma's CAA §110(a)(2) Infrastructure Certification for the 2008 Lead NAAQS, which is currently undergoing internal and EPA Region 6 staff consultation. The public participation procedures document the agency's wider use of electronic dissemination of program information, and lowers emphasis on the use of more costly and narrower/less effective newspaper publication and/or direct mailing of such notices. In accordance with EPA's Guidance Memo entitled, *Regional Consistency for the Administrative Requirements of State Implementation Plan Submittals and the Use of "Letter Notices,"* (April 6, 2011), the State has determined that the public has routine and ready access to the electronic publishing venues provided by DEQ. The procedures provide additional notice methods (e.g., direct mail and/or published newspaper notice) for use if a particular action is likely to be of concern to a particular group or community that does not have routine and ready access to electronic notifications.

If you have questions, please contact Ms. Cheryl Bradley, Manager, AQD Rules and Planning Section, or Mr. Brooks Kirlin, AQD Rules and Planning Section, at (405) 702-4100.

Sincerely

Eddie Terrill
Director, Air Quality Division
Enclosures

cc: Guy Donaldson, Section Chief, Air Planning Section, EPA Region VI (6PD-L)
Jeff Robinson, Section Chief, Air Permits, EPA Region VI (6PD-R)

ec: Carrie Paige, Air Planning Section, EPA Region VI (6PD-L)

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
Procedures for Notice of Opportunity for Public Hearing and Comment
Oklahoma SIP Review/Revision Submittals

Background

A State Implementation Plan (SIP) identifies how that state will attain and/or maintain the primary and secondary National Ambient Air Quality Standards (NAAQS). The SIP contains state regulations and procedures, source-specific requirements, and non-regulatory items such as plans and inventories. The federally enforceable SIP for Oklahoma is compiled in 40 CFR Part 52, Subpart LL. As documented in previously approved SIP submittals under the Clean Air Act (CAA) (including recent Infrastructure Certifications under CAA Section 110(a)(1) and (2)), the Oklahoma DEQ is given the primary responsibility and authority to prepare and implement Oklahoma's air quality management plan under the Oklahoma Environmental Quality Act and the Oklahoma Clean Air Act (*see generally* 27A Okla. Statutes (O.S,) § 2-1-101, *et seq.*).

In addition to these governing statutes, the bulk of Oklahoma's SIP consists of DEQ's Air Quality Rules, which are enacted under the agency, public, gubernatorial, and legislative review processes of the Oklahoma Administrative Procedures, Open Records, and Open Meetings Acts (*see generally* 75 O.S. §§ 250 through 323, 51 O.S. §§ 24A.1 through 24A.29, and 25 O.S. §§ 301 through 314, respectively) and associated administrative rules. SIPs are reviewed and revised by the state from time to time as necessary to accommodate changes in State and Federal statutes, rules, policies, and program requirements. For instance, the CAA requires EPA to periodically review the NAAQS, and Section 110(a)(1) of the CAA requires the state to then review and revise the SIP as necessary each time a NAAQS is issued or revised ("Infrastructure Certification"). Many of these revisions require changes to Title 252, Chapter 100 of the Oklahoma Administrative Code (DEQ's Air Quality Rules) that, once are finalized, are submitted to EPA for formal inclusion in Oklahoma's SIP.

The SIP also includes non-rule components, such as program & implementation descriptions, environmental evaluation documents, and certain individual control measures relied upon to maintain the NAAQS. The State's Regional Haze Plan and recent Infrastructure Certifications are examples of such submittals. After any necessary rulemaking and/or individual proceedings and staff evaluations are completed, a draft SIP document is prepared for submittal to EPA under the Governor's or the Executive Director's signature as appropriate. [For additional details see recently-approved Infrastructure Certification(s).] The remainder of this document describes DEQ's related public participation procedures.

Public Participation Procedures

The Oklahoma Department of Environmental Quality (DEQ) will use the following public participation procedures for State Implementation Plan (SIP) Review/Revision submittals. DEQ has prepared this document to describe related public participation procedures to be carried out under 40 CFR Part 51, as approved by EPA under 40 CFR § 51.102(g).

1. DEQ will provide public notification of the opportunity for participation by prominently posting a public notice on the DEQ web site. At a minimum, the notice will provide a 30-day period and procedures for submission of written comments on the proposed submittal, and the opportunity for a public hearing. The notice will provide the web address for the proposed submittal, and instructions for viewing or obtaining a hard copy. Attachment 1 provides an example of a public notice. At the time that the notification is posted, notification will also be provided to EPA's Region VI office in Dallas and to individuals and entities that have requested email notification. The DEQ may provide additional methods of notice (e.g., direct mail or a published newspaper notice), if the Director believes that significant public interest or other circumstances warrant additional notice[1]. For SIP revisions/submissions, the notice will also inform the public that such SIP will be submitted to EPA for approval into the SIP.

   If the Director believes there is significant public interest, the notice will provide the date, place, and time for a scheduled public hearing. The following statement may be included in the notice: "If no request for a public hearing is received by the close of the 30-day notice period, the hearing will be cancelled, and a notice announcing that the hearing has been cancelled will be posted on this web site (*AQD website*) at least 24 hours prior to scheduled time for the hearing. You may call 405-702-4100 to find out if the hearing has been cancelled."

   If the Director believes there is likely not sufficient public interest to schedule a public hearing, the notice will describe the opportunity and procedures to request a public hearing during the 30-day notification period.

2. If a public hearing is held, it will be conducted under the requirements of OAC 252:4, DEQ's Rules of Practice and Procedure, and the Oklahoma Administrative Procedures Act.

3. Following the close of the comment period and/or public hearing, DEQ will prepare a record of the comments and/or hearing, including a copy of all written comments, a list of all hearing attendees, a summary or transcript of oral comments, and a response to comments, as appropriate. A copy of the record will be provided to EPA upon request.

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1 For example, if a particular action is likely to be of concern to a particular group or community that does not have routine and ready access to electronic notifications.

(Attachment 1)

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
Notice of Opportunity for Public Hearing and Comment
Oklahoma's [*SUBJECT*] SIP Review/Revision

The Oklahoma Department of Environmental Quality (DEQ) will hold a public hearing on the proposed [*Subject SIP Review/Revision*]. The hearing is scheduled for [*Day*], [*Date*], from [*Start Time*] to [*End Time*] in the Multipurpose Room of the DEQ, 707 North Robinson Avenue, Oklahoma City, OK 73102. [**OPTION**: If no request for a public hearing is received by the close of the 30-day notice period, the hearing will be cancelled, and a notice announcing that the hearing has been cancelled will be posted on this web site (http://www.deq.state.ok.us/aqdnew/RulesAndPlanning/index.htm) at least 24 hours prior to scheduled time for the hearing. You may call 405-702-4100 to find out if the hearing has been cancelled.]

[**OPTION**: The Oklahoma Department of Environmental Quality (DEQ) hereby announces a 30-day opportunity to comment on and request a public hearing on the proposed [*Subject SIP Review/Revision*]. If a request for a public hearing is received prior to the close of the 30-day notice period ([*Closing Date*]), a hearing will be scheduled and a notice announcing the hearing details will be posted on this web site (http://www.deq.state.ok.us/aqdnew/RulesAndPlanning/index.htm) at least 30 days prior to the hearing. You may call 405-702-4100 to find out if a hearing has been scheduled.]

Under the Oklahoma Clean Air Act (27A O.S. §§ 2-5-101 thru -117), DEQ is given the primary responsibility and authority to prepare and implement Oklahoma's air quality management plan, compiled in 40 CFR Part 52, Subpart LL. The DEQ prepared the proposed [*Subject SIP Review/Revision*] to comply with the requirements contained in Section [*Section*] of the federal Clean Air Act and 40 CFR Part 51, Requirements for Preparation, Adoption, and Submittal of Implementation Plans. This [*Subject SIP Review/Revision*] was prepared for submittal to the U.S. Environmental Protection Agency (EPA) under [*EPA Guidance, etc.*].

All persons interested in these matters are invited to submit written comments prior to the close of the 30-day notice period ([*Closing Date*]) and/or provide oral comments at the public hearing (if a hearing is requested and held). Persons planning to comment at the hearing may submit a written statement and/or additional information relevant to this matter for inclusion in the record of proceedings of the public hearing. The hearing officer may limit the length of oral presentations to allow all those who wish to provide oral comments an opportunity to do so.

The proposed [*Subject SIP Review/Revision*] is available on the DEQ website at http://www.deq.state.ok.us/aqdnew/RulesAndPlanning/index.htm. Copies may also be obtained from the Department by contacting [*AQD Contact Person*], at (405) 702-4100 or [*AQD contact email address*].

Written comments regarding the proposed [*Subject SIP Review/Revision*] should be mailed to:

Department of Environmental Quality, Air Quality Division
P.O. Box 1677
Oklahoma City, Oklahoma 73101-1677
ATTN: [*AQD Contact Person*]

or emailed to [*AQD contact email address*].

Comments may be submitted by fax to the Air Quality Division, ATTN: [*AQD Contact Person*], at (405) 702-4101.

Should you desire to attend the public hearing but have a disability and need an accommodation, please notify the Air Quality Division three (3) days in advance at (405)702-4216. For the hearing impaired, the TDD relay number is 1-800-522-8506 or 1-800-722-0353, for TDD machine use only.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Region 6
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202 - 2733

August 23, 2012

Mr. Eddie Terrill
Director
Air Quality Division
Oklahoma Department of Environmental Quality
P.O. Box 1677
Oklahoma City, OK 73101

Dear Mr. Terrill,

Thank you for your letter dated August 17, 2012, notifying us of your intention to use internet notice to meet the requirements of public notice and comment for adoption of State Implementation Plans. We have reviewed your procedures for internet public notice and they are consistent with EPA's Guidance memo, "Regional Consistency for the Administrative Requirements of State Implementation Plan Submittals and the use of "Letter Notices" (April 6, 2011)" as well as consistent with the requirements of 40 CFR Part 51. We support the State's practical application of technology to meet this CAA requirement while conserving limited resources.

If you have questions, please feel free to contact me or Carrie Paige at (214) 665-6521.

Sincerely yours,

Thomas Diggs

Thomas Diggs
Associate Director for Air Programs