SUPPLEMENTAL BART DETERMINATION INFORMATION

AMERICAN ELECTRIC POWER ■ NORTHEASTERN POWER PLANT

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For :

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

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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

2. MODELING METHODOLOGY

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 <u>not</u> 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:

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

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:

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

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

Class I Area	Baseline Max. Impact (Δdv)	Baseline 98th %-tile (Δdv)	Baseline # Days > 0.5 Δdv	Unit 4 Shutdown / Unit 3 NO_X Controlled, SO_2 Baseline Max. Impact (Δdv)	Unit 4 Shutdown / Unit 3 NO_X Controlled, SO_2 Baseline 98th %-tile (Δdv)	Unit 4 Shutdown / Unit 3 NO_X Controlled, SO_2 Baseline # 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)	98th %-tile (Δdv)	# Days > 0.5 Δdv	FIP Scenario Max. Impact (Δdv)	98th %-tile (Δdv)	# 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 [j]	$0 [j]	$0 [j]
Property tax	$2,329,850 [j]	$1,164,925 [j]	$3,016,055 [j]
Insurance	$28,781 [j]	$14,390 [j]	$37,257 [j]
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	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	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	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	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	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	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	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	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	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	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

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:__________ By: ______________________________________

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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.