REVISIONS TO THE ARKANSAS REGIONAL HAZE STATE IMPLEMENTATION PLAN

Notice of Data Availability; Extension of Public Comment Period; Rescheduling of Public Hearing

I. <u>Introduction</u>

On October 31, 2017, the Arkansas Department of Environmental Quality (ADEQ) proposed revisions to the Arkansas Regional Haze State Implementation Plan (SIP) to address the following elements of the Regional Haze Rule:

- Best Available Retrofit Technology (BART) compliance dates;
- BART-eligible sources and subject-to-BART sources;
- Select BART determinations:
    - Sulfur dioxide (SO_2) and particulate matter (PM) BART determinations for Arkansas Electric Cooperative Corporation (AECC) Bailey Plant Unit 1;
    - SO2 and PM BART determinations for AECC McClellan Plant Unit 1;
    - SO2 BART determinations for Southwest Power Company (SWEPCO) Flint Creek Plant Boiler No. 1;
    - BART determination for the natural gas firing scenario at Entergy Lake Catherine Plant Unit 4;
    - SO_2 BART determinations under both bituminous and sub-bituminous coal firing scenarios for Entergy White Bluff Units 1 and 2;
    - BART determination for Entergy White Bluff Plant Auxiliary Boiler;
- Reasonable progress goals (RPGs) for the first planning period; and
- Long-term strategy.

The SIP proposed on October 31, 2017 is hereinafter referred to as the “Proposed SIP.”

On December 1, 2017, Entergy voluntarily released information as publicly available that was previously submitted to ADEQ as an asserted trade secret and referred to as confidential business information (CBI) regarding their planned changes in operation at both the White Bluff and Independence Plants.[1] Specifically, the CBI includes Entergy’s intended dates for cessation of

[1] Copies of Entergy’s analyses, including previously redacted information, have been included with this Notice of Data Availability for public review.

coal-fired operations at White Bluff, a BART facility, in 2028 and Independence in 2030. In addition, Entergy released information regarding cost-effectiveness estimates for retrofit technologies for each unit at White Bluff and Independence. Entergy also conducted an alternative reasonable progress analysis. The Proposed SIP seeks comments on ADEQ's determination that low-sulfur coal is the appropriate BART control at the White Bluff facility, based on planned changes in operations occurring at the plant no later than 2030. The Proposed SIP also seeks comment on ADEQ's determination that low sulfur coal at Independence is an appropriate measure to ensure continued reasonable progress. ADEQ is providing this Notice of Data Availability (NODA) for the public's additional consideration as they develop comments on the Proposed SIP.

ADEQ notes that Entergy may have additional obligations regarding reliability and cost recovery with respect to the two facilities referenced in this NODA that are outside the scope of ADEQ's authority and outside the scope of the Proposed SIP..

ADEQ is also extending the public comment period until January 19, 2018. This extension is in response to multiple requests for extension of the public comment period and to provide the public additional time to review the new information being provided in this NODA. ADEQ is also rescheduling the public hearing to January 19, 2018 to accommodate a request and to provide additional time before the public hearing for review of the information being provided with this NODA.

II. <u>Notice of Data Availability</u>

ADEQ is providing this notice of data availability and providing an opportunity for comment on information provided by Entergy to ADEQ that was previously asserted to be a trade secret. Specifically, ADEQ is making publicly available the information provided to ADEQ by Entergy on August 18, 2017 and September 27, 2017.

On August 18, 2017, Entergy submitted an updated five-factor analysis for SO_2 for White Bluff Units 1 and 2. With this analysis, Entergy submitted a letter detailing reasons why some information contained within the analysis is constitutes a trade secret under Arkansas law and must be held confidential. As such, Entergy redacted certain information contained in this

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Energy Services, Inc., on behalf of Entergy Arkansas, Inc. (2017) <u>Updated BART Five-Factor Analysis dated August 18, 2017 for SO2 for Units 1 and 2, White Bluff Steam Electric Station Redfield, Arkansas (AFIN 35-00110) (Public Copy)</u>

Entergy Services, Inc., on behalf of Entergy Arkansas, Inc. (2017) <u>Analysis of Reasonable Progress, Arkansas Regional Haze Program First Planning Period (Public Copy)</u>

submittal including information regarding the remaining useful life of White Bluff Units 1 and 2. Entergy also redacted information regarding capital recovery periods, capital cost, annualized capital cost, average cost-effectiveness for retrofit technologies evaluated. ADEQ did not include any redacted information in the Proposed SIP. On December 1, 2017, Entergy sent a letter to ADEQ releasing their previous claim of confidentiality regarding the August 18, 2017 updated BART analysis for White Bluff.

On September 27, 2017, Entergy submitted an analysis of reasonable progress for the first planning period of the Arkansas Regional Haze Program. With this analysis, Entergy submitted a letter detailing reasons why some of the information contained in the analysis is a trade secret and must be held confidential. As such, Entergy redacted certain information contained in their analysis including information regarding cessation of coal-fired operations at White Bluff and Independence. Entergy also redacted information concerning capital recovery periods for Dry FGD and the remaining useful life for White Bluff and Independence. ADEQ did not rely upon Entergy's reasonable progress analysis for the Proposed SIP. On December 1, 2017, Entergy sent a letter to ADEQ releasing their previous claim of confidentiality regarding the September 27, 2017 reasonable progress analysis.

ADEQ is providing notice of this additional information provided by Entergy due to its potential relevance to the public as they develop comments on the Proposed SIP.

III. <u>Extension of Public Comment Period and Rescheduled Public Hearing</u>

In light of the newly-released information provided with this NODA, as well as requests for extension of the public comment period and public hearing, ADEQ is extending the public comment period on the Proposed SIP to January 19, 2018.

ADEQ will accept written and electronic comments on the Proposed SIP that are received by no later than 11:59 p.m. (Central Time) on Friday, January 19, 2018. Written comments should be mailed to Tricia Treece, Office of Air Quality, Arkansas Department of Environmental Quality, 5301 Northshore Drive, North Little Rock, AR 72118. Electronic comments should be sent to: treecep@adeq.state.ar.us.

The public hearing will be held on January 19, 2018, concurrent with the close of the public comment period. The public hearing will begin at 2:00 p.m. in the Commission Room at the Arkansas Department of Environmental Quality headquarters building, 5301 Northshore Drive, North Little Rock, AR 72118. In the event of inclement weather or other unforeseen circumstances, a decision may be made to postpone the hearing. If the hearing is postponed and rescheduled, a new legal notice will be published to announce the details of the new hearing date and comment period.

Extension of the public comment period to allow for thirty days between the notice of the opportunity to seek comment on the inclusion of new information for consideration by the public regarding facts that may be relevant to the Proposed SIP and the conclusion of the public comment period is consistent with the requirements of Arkansas Code Annotated (Ark. Code Ann.) Section 8-4-317(b)(1) (B), which states that "notice required under subdivision (b)(1)(A) of this section shall afford any interested party at least thirty (30) calendar days in which to submit comments on the proposed state implementation plan submittal in its entirety."

IV. State and Federal Land Manager Consultation

ADEQ began the consultation period on the Proposed SIP with Missouri Department of Natural Resources (Missouri DNR) and the Federal Land Managers (FLMs) for the Class I areas impacted by Arkansas sources on October 27, 2017. On December 11, 2017, ADEQ provided Entergy's publicly available analyses included with this NODA for their review. To provide the FLMs and Missouri DNR with additional time to factor the new information provided by Entergy into their consideration of the Proposed SIP, ADEQ is providing additional time for consultation beyond the sixty day Regional Haze Rule mandated minimum consultation period. ADEQ will continue to consult with Missouri DNR and the FLMs on the Proposed SIP up to January 18, 2018.

Entergy Services, Inc., on behalf of Entergy Arkansas, Inc.
White Bluff Steam Electric Station
Redfield, Arkansas (AFIN 35-00110)

Updated BART Five-Factor Analysis for SO_2 for Units 1 and 2

Submitted to:

Arkansas Department of Environmental Quality (ADEQ)
Office of Air Quality
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TABLE OF CONTENTS

1 EXECUTIVE SUMMARY 1-1

1.1 Report Updates ... 1-1

1.2 Summary of Updated BART Five Factor Analysis ... 1-2

2 INTRODUCTION AND BACKGROUND 2-1

3 EXISTING EMISSIONS AND BASELINE VISIBILITY IMPAIRMENT 3-1

3.1 Baseline Emission Rates ... 3-1

3.2 Baseline Visibility Impairment ... 3-2

4 SO_2 BART EVALUATION 4-1

4.1 Identification of Available Retrofit SO_2 Control Technologies for Unit 1 and Unit 2 ... 4-1

4.2 Eliminate Technically Infeasible SO_2 Control Technologies for Unit 1 and Unit 2 ... 4-1

4.2.1 Fuel Switching – Low-Sulfur Coal ... 4-1

4.2.2 Dry Sorbent Injection ... 4-1

4.2.3 Dry / Semi-Dry Flue Gas Desulfurization ... 4-2

4.2.4 Wet Flue Gas Desulfurization ... 4-3

4.3 Rank of Technically Feasible SO_2 Control Options by Effectiveness for Unit 1 and Unit 2 ... 4-3

4.4 Evaluation of Impacts for Feasible SO_2 Controls for Unit 1 and Unit 2 ... 4-3

4.4.1 Remaining Useful Life ... 4-4

4.4.2 Cost of Compliance ... 4-4

4.4.3 Energy Impacts and Non-Air Quality Impacts ... 4-6

4.5 Evaluation of Visibility Impact of Feasible SO_2 Controls for Unit 1 and Unit 2 ... 4-6

4.6 BART for SO_2 for Unit 1 and Unit 2 ... 4-8

APPENDIX A. CONTROL COST INFORMATION A-1

APPENDIX B. BASELINE VISIBILITY IMPAIRMENT BY POLLUTANT B-1

APPENDIX C. REFINED PM SPECIATION CALCULATIONS C-1

LIST OF TABLES

Table 3-1. Baseline Maximum 24-hour Emission Rates (As Hourly Equivalents) 3-2

Table 3-2. Baseline Visibility Impairment 3-2

Table 4-1. Available SO_2 Control Technologies for Unit 1 and Unit 2 4-1

Table 4-2. Control Effectiveness of Technically Feasible SO_2 Control Technologies 4-3

Table 4-3. Summary of SO_2 Controls Cost Effectiveness for Unit 1 and Unit 2 Based on Actual Costs 4-5

Table 4-4. Summary of SO_2 Controls Cost Effectiveness for Unit 1 and Unit 2 Based on Costs Adjusted for EPA-Exclusions for Illustration Purposes 4-5

Table 4-5. Emission Rates Modeled to Reflect SO_2 Controls for Unit 1 and Unit 2 4-7

Table 4-6. Summary of CALPUFF-Modeled Visibility Impacts from SO_2 Controls for Unit 1 (Across All Modeled Years, 2001-2003) 4-7

Table 4-7. Summary of CALPUFF-Modeled Visibility Impacts from SO_2 Controls for Unit 2 (Across All Modeled Years, 2001-2003) 4-8

Table B-1. Baseline Visibility Impairment Attributable to Unit 1 by Pollutant B-1

Table B-2. Baseline Visibility Impairment Attributable to Unit 2 by Pollutant B-2

1 EXECUTIVE SUMMARY

This report provides an update to the Best Available Retrofit Technology (BART) Five Factor Analysis for sulfur dioxide (SO_2) for Unit 1 (SN-01) and Unit 2 (SN-02) at Entergy Arkansas, Inc.'s (EAI's) White Bluff Steam Electric Station (White Bluff) as well as revising the SO_2 BART conclusion. EAI submitted the original BART Five Factor Analysis to the Arkansas Department of Environmental Quality (ADEQ) on February 21, 2013, with revisions on June 10, 2013 and October 15, 2013.

- Unit 1 (SN-01) is a primary boiler with a maximum net power rating of 850 megawatts (MW) and a nominal heat input capacity of 8,950 million British thermal units per hour (MMBtu/hr). The boiler burns sub-bituminous or bituminous coal[1] as the primary fuel and No. 2 fuel oil or biofuel as a start-up fuel, and it is currently equipped with an electrostatic precipitator (ESP) for particulate matter (PM) control.
- Unit 2 (SN-02) is identical in design to Unit 1. It is a primary boiler with a maximum net power rating of 850 MW and a nominal heat input capacity of 8,950 MMBtu/hr. The boiler burns sub-bituminous or bituminous coal[2] as the primary fuel and No. 2 fuel oil or biofuel as a start-up fuel, and it is currently equipped with an ESP for PM control.

Specific updates incorporated in this version of the report are outlined below.

1.1 REPORT UPDATES

This report includes the following updates to the previous SO_2 Five Factor Analysis for White Bluff Units 1 and 2:

1. Updating the baseline period to 2009-2013.
2. Incorporating new information regarding the remaining useful life (RUL) of the units.
3. Incorporating a new control scenario representing combustion of only low-sulfur coal (LSC).
4. Incorporating additional information (i.e., cost information and modeling results) related to control options involving Dry Sorbent Injection (DSI).
5. Updating all modeling to reflect the newest methodologies for dividing ("speciating") particulate matter (PM or PM_{10})[3] emissions into its constituents.
6. Updating the SO_2 BART conclusion in consideration of the new information and updates listed above.

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[1] The coal-fired units at White Bluff primarily burn sub-bituminous coal, but are permitted to burn bituminous or sub-bituminous coal. Only sub-bituminous coals were burned during the baseline periods evaluated in this analysis.

[2] Ibid.

[3] All PM represented in this report is assumed to have a mass mean diameter smaller than ten microns.

1.2 SUMMARY OF UPDATED BART FIVE FACTOR ANALYSIS

Trinity conducted the below five-step analysis based on EPA's BART Guidelines[4] in 40 CFR Part 51 and other EPA guidance[5] to evaluate SO_2 BART for Units 1 and 2:

1. Identifying all available retrofit control technologies;
2. Eliminating technically infeasible control technologies;
3. Evaluating the control effectiveness of remaining control technologies;
4. Evaluating impacts and documenting the results; and
5. Evaluating visibility impacts.

The updated BART Five Factor Analysis concludes that combustion of LSC constitutes BART for Unit 1 and Unit 2 in light of the updated RUL. The proposed BART emission rate for SO_2 is 0.6 pounds per MMBtu (lb/MMBtu) on a rolling 30-day average.

[4] The BART guidelines were published as amendments to EPA's Regional Haze Rule (RHR) at 40 CFR 51.308 on July 6, 2005.

[5] April 26, 2012, letter from Mr. Guy Donaldson, EPA Region VI, to Mr. Anthony Davis, ADEQ.

2 INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to pristine conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to pristine conditions in 156 specific areas across the United States known as Class I areas. The CAA defines Class I areas as certain national parks (larger than 6,000 acres), wilderness areas (larger than 5,000 acres), national memorial parks (larger than 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the Best Available Retrofit Technology (BART) rule, which included guidance for making source-specific BART determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant,
(2) Began operation between August 7, 1962, and August 7, 1977, and
(3) Are included as one of the 26 listed source categories in the guidance.

A BART-eligible source is subject to BART if the source is "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." For the purpose of determining which sources are subject to BART, a 1.0 Δdv change or more from an individual source is considered to "cause" visibility impairment, and a change of 0.5 Δdv is considered to "contribute" to impairment, which therefore establishes 0.5 Δdv as a numerical screening threshold for subject-to-BART determinations.[6] According to the BART guidelines, the CALPUFF modeling system (CALPUFF) or any other appropriate dispersion model can be used to predict the visibility impacts.[7] The model-predicted visibility impact, specifically when using CALPUFF the 98th percentile impact measured against natural background (and not the maximum impact), is compared to the 0.5 Δdv threshold to determine if the source is anticipated to cause or contribute to the visibility impairment.[8]

Once it is determined that a source is subject to BART, a BART determination must address air pollution control measures for the source. The visibility regulations define BART as follows:

> *…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…[a BART-eligible source]. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the cost of compliance, the energy and non-air quality*

[6] "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule," 70 Fed. Reg. 39,116-18 (July 6, 2005).

[7] Trinity and EAI assert that CALPUFF is not the most appropriate model for estimating visibility impacts. Due to its numerous inherent limitations (e.g., limited chemistry mechanism, distance limitations, blanket background ammonia values, etc.), CALPUFF does not yield reliable results. Furthermore, CALPUFF is no longer an EPA-preferred model, which further indicates CALPUFF's unreliability. More advanced models like the Comprehensive Air Quality Model with Extensions (CAMx)—if processed appropriately—can yield more reliable characterizations of visibility impairment. Nevertheless (without waiver), CALPUFF modeling will continue to be presented in this report for consistency with past submittals.

[8] Id. at 39,163.

environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

The BART Guidelines state that a BART determination should address the following five statutory factors:

1. Existing controls;
2. Cost of controls;
3. Energy and non-air quality environmental impacts;
4. Remaining useful life of the source; and
5. Degree of visibility improvement as a result of controls.

Further, the BART Guidelines indicate that the five basic steps in a BART analysis can be summarized as follows:

1. Identify all available retrofit control technologies;
2. Eliminate technically infeasible control technologies;
3. Evaluate the control effectiveness of remaining control technologies;
4. Evaluate impacts and document the results; and
5. Evaluate visibility impacts.

As described in the above-referenced, previous submittals, the boilers at White Bluff meet the three BART-eligibility criteria, and the existing visibility impairment is modeled at greater than 0.5 Δdv in at least one Class I area. Thus, the White Bluff units are subject to BART.

3 EXISTING EMISSIONS AND BASELINE VISIBILITY IMPAIRMENT

Five Factor Analyses require the determination of unit-specific baseline visibility impairment values to which any post-control scenarios can be compared. The unit-specific baseline modeling analyses are built upon, but are distinguished from, the baseline (a.k.a., “screening”) modeling for the collection of BART eligible units at each source that is completed to determine if a BART eligible source is subject to BART. EAI is not updating the subject-to-BART determination at this time.

This section summarizes the baseline visibility impairment attributable to each of White Bluff’s units based on CALPUFF air quality modeling conducted by Trinity.[9] Trinity conducted the modeling using the same protocol, methodologies, and inputs (except where specifically updated as described in this report) as presented in the October 15, 2013 submittal. The protocol and details method descriptions are not included with this report because nothing has changed and the CALMET dataset developed per the protocol has been used – and approved by EPA – numerous times since its development.

While this report updates the BART Five Factor Analysis for SO_2 emissions specifically, BART modeling must consider emissions of all visibility-affecting pollutants (VAP), including SO_2, oxides of nitrogen (NO_X), and speciated particulate matter, including filterable coarse particulate matter (PMc), filterable fine particulate matter (PMf), elemental carbon (EC), inorganic condensable particulate matter (IOR CPM) as sulfates (SO_4), and organic condensable particulate matter (OR CPM), also referred to as secondary organic aerosols (SOA).

3.1 BASELINE EMISSION RATES

The updated modeled NO_X and SO_2 emission rates for Unit 1 and Unit 2 are the highest actual 24-hour emission rates based on Clean Air Markets Database (CAMD) data from 2009-2013.[10] The updated modeled PM_{10} emission rates for Unit 1 and Unit 2 are based on emission factors from AP-42 for filterable PM_{10} and condensable PM (with a 99.5 percent control efficiency for ESP applied to the PM_{10} filterable fraction) used in conjunction with the average 2009-2013 coal heating value and ash content (as a percentage of mass).[11] Emission rates for specific PM_{10} species were calculated using the monitored filterable PM rate and the National Park Service (NPS) “speciation spreadsheet” for *Dry Bottom Boiler Burning Pulverized Coal using only ESP*[12] except for SO_4, which was calculated using an Electric Power Research Institute (EPRI) methodology that considers the SO_2 to SO_4 conversion rate and SO_4 reduction factors for various downstream equipment.[13] Table 3-1 summarizes the emission rates that were modeled for SO_2, NO_X, and PM_{10}, including the speciated PM_{10} emissions.

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[9] See footnote 7, above.

[10] The use of this baseline is a conservative approach. EAI would be justified in using a more recent baseline with lower emissions that would result in higher cost effectiveness values.

[11] AP-42, Chapter 1 External Combustion Sources, Section 1.1 Bituminous and Subbituminous Coal Combustion, Table 1.1-5, page 1.1-24 (September 1998).

[12] The baseline speciation is based on the NPS Workbook for a Dry Bottom Boiler burning Pulverized Coal using an ESP. Based on average 2009-2013 values, the following input values were used: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr heat input, and a baseline total PM_{10} emission rate of 119.2 lb/hr at both White Bluff Unit 1 and Unit 2. NPS: http://www.nature.nps.gov/air/Permits/ect/index.cfm.

[13] Electric Power Research Institute (EPRI) Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: EPRI, Technical Update, Palo Alto, CA: March 2012. 1023790.

Table 3-1. Baseline Maximum 24-hour Emission Rates (As Hourly Equivalents)

Unit	SO_2 (lb/hr)	NO_X (lb/hr)	Total PM_{10} (lb/hr)	SO_4 (lb/hr)	PM_c (lb/hr)	PM_f (lb/hr)	SOA (lb/hr)	EC (lb/hr)
SN-01	6,771.9	3,355.4	119.2	5.1	40.4	31.1	9.3	1.2
SN-02	6,622.3	3,590.5	119.2	5.0	40.4	31.1	9.3	1.2

3.2 BASELINE VISIBILITY IMPAIRMENT

Trinity conducted modeling to estimate the current visibility impairment attributable to Unit 1 and Unit 2 in four Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING) using the CALPUFF dispersion model.[14] Table 3-2 provides a summary of the modeled visibility impairment attributable to Unit 1 and Unit 2 based on the emission rates shown in Table 3-1. This table shows the 98th percentile impacts in Δdv and the number of days with impacts greater than 0.5 Δdv.

Table 3-2. Baseline Visibility Impairment

Unit	Year [A]	CACR		UPBU		HERC		MING	
		98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5
SN-01	2001	1.505	38	1.051	30	0.925	24	0.802	16
	2002	1.306	29	0.742	15	0.567	10	0.708	21
	2003	1.053	32	1.033	24	0.704	15	0.666	14
SN-02	2001	1.533	39	1.059	30	0.912	25	0.819	15
	2002	1.322	29	0.739	16	0.568	11	0.719	20
	2003	1.059	32	1.03	25	0.72	16	0.678	14

[A] Meteorological data year modeled.

[14] Due to an EPA-requested change in meteorological data (to a refined, or "NO OBS = 0", dataset), which excluded the Sipsey Class 1 Area from the modeling domain, Sipsey was not included in this analysis. See also footnote 7 above.

4.1 IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES FOR UNIT 1 AND UNIT 2

The boilers burn primarily coal. Sulfur oxides, SO_X, are generated during coal combustion from the oxidation of sulfur contained in the fuel. SO_X emissions are almost entirely dependent on the sulfur content of the fuel and are generally not affected by boiler size or burner design. SO_X emissions from conventional combustion systems are predominantly in the form of SO_2. Since SO_2 is the predominant sulfur compound emitted from Unit 1 and Unit 2, the BART analysis is specific to emissions of SO_2. Reductions in emissions of SO_2 are expected to reduce visibility impairment by reducing sulfate (SO_4) formation.

Step 1 of the top-down control review is to identify available retrofit control options for SO_2. The available SO_2 retrofit control technologies for Unit 1 and Unit 2 are summarized in Table 4-1.

Table 4-1. Available SO_2 Control Technologies for Unit 1 and Unit 2

SO_2 Control Technologies
Fuel Switching – Low-Sulfur Coal (LSC)
Dry Sorbent Injection (DSI)
Dry / Semi-Dry Flue Gas Desulfurization (DFGD), e.g., Spray Dryer Absorber (SDA)
Wet Scrubbing, i.e., Wet Flue Gas Desulfurization (WFGD)

4.2 ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES FOR UNIT 1 AND UNIT 2

Step 2 of the BART determination is to eliminate technically infeasible SO_2 control technologies that were identified in Step 1.

4.2.1 Fuel Switching - Low-Sulfur Coal

With an achievable emission level of 0.6 lb/MMBtu, switching to LSC can reduce SO_2 emissions by approximately 8.75 percent compared to baseline levels.[15]

4.2.2 Dry Sorbent Injection

DSI involves the injection of a sorbent (e.g., Trona) into the exhaust gas stream where acid gases such as hydrogen chloride (HCl) and SO_2 react with and become entrained in the sorbent. The stream then passes through a particulate control device to remove the sorbent along with the entrained SO_2. The process was developed as a lower cost FGD option because the mixing of the SO_2 and sorbent occurs directly in the exhaust gas stream rather than in a separate vessel. Sorbent injection control efficiency depends on residence time, gas stream temperature, and limitations of the particulate control device.

[15] Calculated based on a comparison of the maximum 30 boiler operating day SO_2 emission rate during the baseline period to the proposed limit for low-sulfur coal of 0.6 lb/MMBtu.

DSI is a technically feasible yet seldom used technology for moderate to high removal of SO_2 from coal-fired power plants, with limited full-scale installations for SO_2 control. A significant amount of testing of DSI for SO_2 control has been performed in recent years. This testing has shown that a wide range of performance is achievable (up to 80 or 90 percent SO_2 reduction in some cases). However, this testing has also shown that there are many factors that can impact the performance of these reagents, including particle size (milling), residence time, temperature, and the particulate collection equipment. The primary lesson learned through this testing is that each unit is unique, with various factors that can impact the achievable performance or required reagent feed rate. Different performance has even been seen on sister units. Therefore, it is critical to perform a demonstration or Proof of Concept test at each facility.

A demonstration has not to-date been performed on the White Bluff units to show the achievable SO_2 control and associated reagent feed rates. The cost reports developed by S&L, included in Appendix A, show predicted performance and required reagent rates based on Sargent & Lundy's (S&L's) extensive experience with DSI testing and previous work with the White Bluff units. Two DSI technologies are considered for White Bluff: "DSI", which would utilize the existing ESP, and "enhanced DSI", which would include installation of a fabric filter or baghouse. Enhanced DSI should achieve greater SO_2 reductions because the installation of a fabric filter increases residence time and improves collection efficiency to allow more sorbent to be injected. The S&L reports present predicted performance levels (SO_2 emission rates) for DSI and enhanced DSI of 0.35 lb/MMBtu and 0.15 lb/MMBtu, respectively. Because the actual performance and required reagent rates may vary from the predicted values due to unforeseen site-specific conditions, it is possible that the capital and annual costs represented in the S&L reports, and in Section 4.4.2 of this report, could also vary. If a significantly higher injection rate were actually required to achieve the same performance level (SO_2 emission rate) then the capital and annual costs, and corresponding cost-effectiveness of the DSI technologies, could dramatically increase.

Furthermore, DSI has yet to be demonstrated on similarly sized units to those at White Bluff. An important consideration for DSI technology is the design throughput of the system, beyond just the size and achievable performance (SO_2 emission rate). The largest DSI system installed and operating has a design feed rate of 12 tons/hour, while most of the installed systems inject approximately five to six tons/hour. The predicted injection rate for the White Bluff enhanced DSI case is approximately 15 tons/hour. The greater the injection rates, the more issues associated with supply and delivery logistics that arise. At 15 tons/hour (per unit) White Bluff would consume one railcar (100-ton capacity) of Trona every 3.3 hours if both units are operating at full load.

Prior to moving forward with DSI technology as a compliance strategy, a demonstration test would need to be performed to confirm the feasibility, achievable performance and balance of plant impacts (brown plume formation, ash handling modifications, landfill/leachate considerations and impact to mercury control). The balance of plant impacts have been addressed as part of the S&L cost reports based on typical assumptions, but would also be impacted should the design injection rate vary. Any compliance strategy which were to rely on DSI technology would need to be contingent on successful completion of a demonstration test.

4.2.3 Dry / Semi-Dry Flue Gas Desulfurization

Of the various designs for dry or semi-dry FGD systems, the most popular is the Spray Dryer Absorber (SDA) design. In the SDA design, a fine mist of lime slurry is sprayed into an absorption tower 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 heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower, resulting in the formation of a dry powder that is carried out with the gas and collected with a fabric filter.

SDA systems can achieve control efficiencies ranging from 60 to 95 percent.[16] SDA is a technically feasible option for control of SO_2 from Unit 1 and Unit 2. Based on a site-specific study completed by S&L, SDA could technically achieve an SO_2 emission rate of 0.06 lb/MMBtu at Unit 1 and Unit 2.

4.2.4 Wet Flue Gas Desulfurization

While WFGD is technically feasible, it is not expected to achieve significant reductions beyond DFGD/SDA and was eliminated in the previous analyses and in EPA's final regulations (SIP approval and FIP). Accordingly, WFGD is not considered further in this analysis.

4.3 RANK OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS BY EFFECTIVENESS FOR UNIT 1 AND UNIT 2

The third step in the BART analysis is to rank the technically feasible options according to their effectiveness in reducing SO_2.
Table 4-2Table 4-2 provides a ranking of the control levels for the controls listed in the previous section.

Table 4-2. Control Effectiveness of Technically Feasible SO_2 Control Technologies

Control Technology	Achievable Emission Rate (lb/MMBtu) [A]
Semi-Dry Scrubber (SDA)	0.06
Enhanced DSI	0.15
DSI	0.35
Low Sulfur Coal	0.6

4.4 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS FOR UNIT 1 AND UNIT 2

The fourth step in the BART analysis is the impact analysis, which evaluates the impacts for the control options deemed feasible in Step 2. This analysis typically is conducted to demonstrate that the most effective control technology does not necessarily constitute BART. The BART guidelines list the four factors to be considered in the impact analysis:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The RUL of the source

Because the RUL of the source directly affects the cost of compliance, RUL is considered first.

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

4.4.1 Remaining Useful Life

EAI anticipates Unit 1 and Unit 2 will cease to use coal by end of year 2028, and, upon acceptance of the BART determinations contained herein in an approved SIP, is prepared to take an enforceable restriction to this effect.

4.4.2 Cost of Compliance

The capital costs and annual operating and maintenance costs for the considered control options, except for the LSC option, were developed by S&L and are included in Appendix A. The annual cost increase due to burning only LSC is based on a cost premium of $0.50 per ton, which was the premium provided to EAI's fuel purchasing department by its coal suppliers. For the S&L-developed costs, two sets of values are presented. The first, in Table 4-3, is the actual cost estimated for each unit and control option. The second, in Table 4-4Table 4-4, is the estimated cost after excluding cost items that EPA has historically claimed should not be accounted for in BART cost effectiveness calculations. An example of an excluded cost is Allowance for Funds Used During Construction (AFUDC). AFUDC represents the interest expense incurred on the investment in a large capital project, such as a FGD installation, which can take several years to complete (≥ 5 years). Although interest expenses will certainly be incurred on such a project, and AFUDC is typically considered as part of the capital cost of such a project for standard accounting and rate-making purposes, EPA Region 6 has expressed concern with the inclusion of AFUDC and certain other costs. EAI disagrees and believes that determining the cost effectiveness of the control options must realistically reflect the actual cost of compliance. *See* EAI's comments on the proposed FIP.[17] Nonetheless, for completeness, this analysis shows a range of cost effectiveness both including AFUDC and other costs and excluding those costs.

Trinity annualized the capital costs based on capital recovery periods reflecting the total amount of time that the control option could be employed until the unit ceases to use coal at the end of 2028. For the purpose of this report, the start of operation for the SDA option is assumed to be the end of 2021.[18] Therefore, the capital recovery period for SDA is set at seven (7) years (2028 – 2021 = 7 years). The LSC and DSI options can be employed two (2) years earlier than SDA which, for purposes of this report, is assumed to be the end of 2019. Therefore, the capital recovery period for these control options is set at nine (9) years (2028 – 2019 = 9 years).

Trinity determined the values for annual tons of SO_2 reduced by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The baseline annual emission rate was based on the average rate for the 2009-2013 baseline period.[19] The controlled annual emission rates were based on the lb/MMBtu levels listed in Table 4-2 multiplied by the future annual heat input, which was based on the average actual heat input from CAMD for the 2009-2013 baseline period. For the LSC scenario, "controlled" annual emission rates were based on an 8.75 percent decrease compared to baseline annual emission rates, which is estimated by comparing the maximum 30-boiler operating day rolling average to the controlled emission rate of 0.6 lb/MMBtu.

The cost effectiveness in dollars per ton of SO_2 reduced was determined by dividing the annualized cost of control by the annual tons reduced. Table 4-3 presents a summary of the cost effectiveness for each control

[17] Entergy Arkansas Inc. "Comments On the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas" (EPA Docket ID No. EPA-R06-OAR-2015-0189), August 7, 2015, pp. 10-11.

[18] October 27, 2021 per 81 Fed. Reg. Vol. 81, p. 66416. However, given that actual installation would take at least five years, SDA likely could not be installed until 2023 or later.

[19] As noted above, this is a conservative baseline, and EAI would have been justified in using a more recent baseline with lower emissions that would have resulted in generally higher cost effectiveness values.

option. The cost of switching to low sulfur coal is less than $1,200/ton of SO_2 reduced. The actual cost effectiveness of the add-on controls is economically infeasible at more than $7,000/ton of SO_2 reduced. It's noted (without waiver) that the cost effectiveness of add-on controls even when excluding certain costs for which EPA has expressed concern (e.g., AFUDC), but that will be incurred as explained above, also results in economic infeasibility, at more than approximately $5,400/ton.[20]

Table 4-3. Summary of SO_2 Controls Cost Effectiveness for Unit 1 and Unit 2 Based on Actual Costs

Unit & Control Option	Baseline Emission Rate (tpy)	Controlled Emission Rate (tpy)	Capital Cost ($MM)	Annualized Capital Cost ($MM/yr)	Annual O&M Cost ($MM/yr)	Average Cost Effective-ness ($/ton)	Incremental Cost Effective-ness v. LSC ($/ton)
SN-01 – LSC	15,939	14,544	0	0	1.60	1,150	
SN-02 – LSC	16,034	14,631	0	0	1.61	1,148	
SN-01 – DSI	15,939	9,770	190.11	29.18	14.91	7,148	8,900
SN-02 – DSI	16,034	9,807	190.11	29.18	14.91	7,081	8,807
SN-01 – Enhanced DSI	15,939	4,187	393.74	60.44	26.19	7,372	8,209
SN-02 – Enhanced DSI	16,034	4,203	393.74	60.44	26.19	7,322	8,153
SN-01 – SDA	15,939	1,675	495.74	92.01	9.60	7,124	7,771
SN-02 – SDA	16,034	1,681	495.74	92.01	9.60	7,080	7,722

Table 4-4. Summary of SO_2 Controls Cost Effectiveness for Unit 1 and Unit 2 Based on Costs Adjusted for EPA-Exclusions for Illustration Purposes

Unit & Control Option	Baseline Emission Rate (tpy)	Controlled Emission Rate (tpy)	Capital Cost ($MM)	Annualized Capital Cost ($MM/yr)	Annual O&M Cost ($MM/yr)	Average Cost Effective-ness ($/ton)	Incremental Cost Effective-ness v. LSC ($/ton)
SN-01 – LSC	15,939	14,544	0	0	1.60	1,150	
SN-02 – LSC	16,034	14,631	0	0	1.61	1,148	
SN-01 – DSI	15,939	9,770	154.79	23.76	14.91	6,269	7,764
SN-02 – DSI	16,034	9,807	154.79	23.76	14.91	6,211	7,683
SN-01 – Enhanced DSI	15,939	4,187	321.42	49.34	26.19	6,427	7,137
SN-02 – Enhanced DSI	16,034	4,203	321.42	49.34	26.19	6,384	7,088
SN-01 – SDA	15,939	1,675	364.83	67.71	9.60	5,420	5,883
SN-02 – SDA	16,034	1,681	364.83	67.71	9.60	5,387	5,846

[20] Issues raised on appeal of the federal plan include EPA's use of undervalued cost of controls. However, without waiver of any claims or arguments, EPA's estimates also support the conclusion that SDA is not cost effective. Using EPA's estimates of capital cost ($247,709,875), total O&M cost ($16,877,127), and emissions reductions (14,363 tpy for Unit 1 and 15,221 tpy for Unit 2), adjusted only to consider the shortened remaining useful life value discussed above, the average cost effectiveness values for SDA are $4,376/ton for Unit 1 and $4,129 for Unit 2.

4.4.3 Energy Impacts and Non-Air Quality Impacts

There are numerous energy impacts and adverse non-air quality environmental impacts associated with the add-on controls under consideration. Some examples related to the use of DSI include (a) the need for substantial storage and transportation – both delivery via rail and conveyance on site – of Trona, (b) the forced abandonment of the beneficial re-use of fly ash, and (c) potential negative impacts on the PM control device.[21] These impacts are more fully addressed for all the considered control options in the S&L reports included in Appendix A.

4.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE SO_2 CONTROLS FOR UNIT 1 AND UNIT 2

Trinity conducted an impact analysis to assess the visibility improvement achieved. The impact analysis compared the impacts associated with the baseline emission rates to the impacts associated with the maximum emission rates representative of each control option.

Table 4-5 summarizes the lb/hr emission rates that were modeled to reflect each control option. The NO_X and total PM_{10} emission rates were modeled at the revised 2009-2013 baseline rates. The applicable NPS speciation spreadsheets were relied upon to determine emission rates for PM species.[22,23,24] SO_4 emission rates were independently calculated using an EPRI methodology that considers the SO_2 to SO_4 conversion rate and SO_4 reduction factors for various downstream equipment.[25]

[21] Sargent & Lundy, *Entergy Arkansas, Inc. White Bluff DSI Cost Estimate Basis Document*, SL-014000 Final, Rev. 0, August 3, 2017, pp. 6-10. *See* Appendix A of this report.

[22] Low sulfur coal PM speciation is based on the NPS Workbook for a Dry Bottom Boiler burning Pulverized Coal using an ESP. The following values were input: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr heat input, and a baseline total PM_{10} emission rate of 119.2 lb/hr at White Bluff Unit 1 and Unit 2. NPS: http://www.nature.nps.gov/air/Permits/ect/index.cfm.

[23] DSI and Enhanced DSI PM speciations are based on the NPS workbooks for a Dry Bottom Boiler burning Pulverized Coal using an FGD system with an ESP or Fabric Filter. The following values were input: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr heat input, and a baseline total PM_{10} emission rate of 119.2 lb/hr at White Bluff Unit 1 and Unit 2. NPS: Ibid.

[24] DFGD speciation is based on the NPS workbook for a Dry Bottom Boiler burning Pulverized Coal using an FGD system with a Fabric Filter. The following values were input: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr, and a baseline total PM_{10} emission rate of 119.2 lb/hr at White Bluff Unit 1 and Unit 2. NPS: Ibid.

[25] Electric Power Research Institute (EPRI) Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: EPRI, Technical Update, Palo Alto, CA: March 2012. 1023790.

Table 4-5. Emission Rates Modeled to Reflect SO_2 Controls for Unit 1 and Unit 2

Unit & Control Option	SO_2 (lb/hr)	SO_4 [A] (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	EC (lb/hr)	SOA (lb/hr)	Total PM_{10} (lb/hr)
SN-01 – LSC	5,370.0	4.0	3,355.4	40.4	31.1	1.2	9.3	119.2
SN-02 – LSC	5,370.0	4.0	3,590.5	40.4	31.1	1.2	9.3	119.2
SN-01 – DSI	3,132.5	0.5	3,355.4	29.0	22.4	0.9	13.4	119.2
SN-02 – DSI	3,132.5	0.5	3,590.5	29.0	22.4	0.9	13.4	119.2
SN-01 – Enhanced DSI	1,342.5	0.02	3,355.4	13.4	12.9	0.5	18.5	119.2
SN-02 – Enhanced DSI	1,342.5	0.02	3,590.5	13.4	12.9	0.5	18.5	119.2
SN-01 – SDA	537.0	0.01	3,355.4	13.4	12.9	0.5	18.5	119.2
SN-02 – SDA	537.0	0.01	3,590.5	13.4	12.9	0.5	18.5	119.2

[A] SO_4 as it is displayed in this table represents ammonium sulfate.

Comparisons of the existing/baseline visibility impacts and the post-control visibility impacts are provided in Table 4-6 and Table 4-7.

Table 4-6. Summary of CALPUFF-Modeled Visibility Impacts from SO_2 Controls for Unit 1 (Across All Modeled Years, 2001-2003)

Scenario	CACR		UBPU		HERC		MING	
	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv
Baseline	1.505	99	1.051	69	0.925	49	0.802	51
LSC	1.376	89	0.908	54	0.758	34	0.687	40
Improvement over baseline	*0.129*	*10*	*0.143*	*15*	*0.167*	*15*	*0.115*	*11*
DSI	1.197	64	0.676	30	0.584	19	0.469	17
Improvement over baseline	*0.308*	*35*	*0.375*	*39*	*0.341*	*30*	*0.333*	*34*
Improvement over LSC	*0.179*	*25*	*0.232*	*24*	*0.174*	*15*	*0.218*	*23*
Enhanced DSI	1.013	41	0.496	14	0.458	11	0.366	6
Improvement over baseline	*0.492*	*58*	*0.555*	*55*	*0.467*	*38*	*0.436*	*45*
Improvement over LSC	*0.363*	*48*	*0.412*	*40*	*0.300*	*23*	*0.321*	*34*
Improvement over DSI	*0.184*	*23*	*0.180*	*16*	*0.126*	*8*	*0.103*	*11*
SDA	0.902	35	0.409	7	0.400	6	0.298	2
Improvement over baseline	*0.603*	*64*	*0.642*	*62*	*0.525*	*43*	*0.504*	*49*
Improvement over LSC	*0.474*	*54*	*0.499*	*47*	*0.358*	*28*	*0.389*	*38*
Improvement over DSI	*0.295*	*29*	*0.267*	*23*	*0.184*	*13*	*0.171*	*15*
Improvement over Enhanced DSI	*0.111*	*6*	*0.087*	*7*	*0.058*	*5*	*0.068*	*4*

Table 4-7. Summary of CALPUFF-Modeled Visibility Impacts from SO_2 Controls for Unit 2 (Across All Modeled Years, 2001-2003)

	CACR		UBPU		HERC		MING	
Scenario	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**
Baseline	1.533	100	1.059	71	0.912	52	0.819	49
LSC	1.436	89	0.932	55	0.775	35	0.697	41
Improvement over baseline	*0.097*	*11*	*0.127*	*16*	*0.137*	*17*	*0.122*	*8*
DSI	1.259	66	0.700	31	0.609	19	0.486	18
Improvement over baseline	*0.274*	*34*	*0.359*	*40*	*0.303*	*33*	*0.333*	*31*
Improvement over LSC	*0.177*	*23*	*0.232*	*24*	*0.166*	*16*	*0.211*	*23*
Enhanced DSI	1.073	42	0.528	17	0.483	12	0.384	7
Improvement over baseline	*0.460*	*58*	*0.531*	*54*	*0.429*	*40*	*0.435*	*42*
Improvement over LSC	*0.363*	*47*	*0.404*	*38*	*0.292*	*23*	*0.313*	*34*
Improvement over DSI	*0.186*	*24*	*0.172*	*14*	*0.126*	*7*	*0.102*	*11*
SDA	0.959	37	0.427	12	0.426	8	0.318	3
Improvement over baseline	*0.574*	*63*	*0.632*	*59*	*0.486*	*44*	*0.501*	*46*
Improvement over LSC	*0.477*	*52*	*0.505*	*43*	*0.349*	*27*	*0.379*	*38*
Improvement over DSI	*0.300*	*29*	*0.273*	*19*	*0.183*	*11*	*0.168*	*15*
Improvement over Enhanced DSI	*0.114*	*5*	*0.101*	*5*	*0.057*	*4*	*0.066*	*4*

4.6 BART FOR SO_2 FOR UNIT 1 AND UNIT 2

Based on the costs of the control options listed above, BART for Unit 1 and Unit 2, when considering the updated RUL, would be an emission level of 0.6 lb/MMBtu based on the use of low-sulfur coal.

APPENDIX A. CONTROL COST INFORMATION

SO_2 CONTROL COST INFORMATION – LAST UPDATED AUGUST 2017

Table B-8. Baseline Visibility Impairment Attributable to Unit 1 by Pollutant

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek							
2001	2.912	1.505	38	74.33	25.34	0.17	0.15
2002	2.048	1.306	29	61.53	34.59	0.83	3.04
2003	4.020	1.053	32	47.92	50.35	0.35	1.39
Upper Buffalo							
2001	2.089	1.051	30	68.58	31.17	0.26	0.00
2002	1.438	0.742	15	79.11	20.19	0.37	0.32
2003	1.773	1.033	24	79.79	19.92	0.28	0.00
Hercules Glades							
2001	1.643	0.925	24	90.21	9.56	0.23	0.00
2002	1.184	0.567	10	74.20	25.45	0.25	0.10
2003	1.977	0.704	15	86.02	13.73	0.25	0.00
Mingo							
2001	1.538	0.802	16	51.46	48.03	0.39	0.12
2002	0.898	0.708	21	54.87	44.82	0.31	0.01
2003	1.003	0.666	14	57.31	41.18	0.41	1.11

Table B-9. Baseline Visibility Impairment Attributable to Unit 2 by Pollutant

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek							
2001	2.994	1.533	39	36.23	60.75	0.74	2.28
2002	2.098	1.322	29	59.43	36.53	0.82	3.22
2003	4.084	1.059	32	96.37	3.38	0.24	0.01
Upper Buffalo							
2001	2.066	1.059	30	66.54	33.21	0.26	0.00
2002	1.447	0.739	16	77.57	21.71	0.37	0.35
2003	1.791	1.030	25	78.24	21.46	0.28	0.00
Hercules Glades							
2001	1.665	0.912	25	89.39	10.38	0.23	0.00
2002	1.185	0.568	11	72.38	27.26	0.25	0.11
2003	1.947	0.720	16	40.35	58.44	0.40	0.82
Mingo							
2001	1.580	0.819	15	81.62	17.93	0.33	0.12
2002	0.886	0.719	20	58.93	40.66	0.19	0.22
2003	0.999	0.678	14	55.08	43.36	0.40	1.17

APPENDIX C. REFINED PM SPECIATION CALCULATIONS

Entergy Services, Inc., on behalf of Entergy Arkansas, Inc.

Analysis of Reasonable Progress
Arkansas Regional Haze Program
First Planning Period

Submitted to:

Arkansas Department of Environmental Quality (ADEQ)
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September 27, 2017

Trinity Project 173702.0014

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TABLE OF CONTENTS

1. EXECUTIVE SUMMARY 1-1

2. INTRODUCTION TO VISIBILITY AND HAZE INDEX 2-1

3. REGIONAL HAZE RULE 3-1

4. RECENT IMPROVE MONITORING DATA 4-1

5. MONITORING DATA COMPARED TO REGIONAL HAZE GOALS 5-1

6. REGIONAL HAZE REQUIREMENTS FOR FIRST PLANNING PERIOD 6-1

7. LONG TERM STRATEGY CONSIDERATIONS 7-1

APPENDIX A: ANALYSIS OF SOURCE CATEGORY AND SOURCE-SPECIFIC CONTRIBUTIONS TO CLASS I AREA VISIBILITY IMPACTS A-1

APPENDIX B: OBSERVATIONS COMPARED TO UNIFORM RATES OF PROGRESS FOR MISSOURI'S CLASS I AREAS B-1

APPENDIX C: CONTROLS ON WHICH THE BART EMISSIONS LIMITS ARE BASED C-1

LIST OF FIGURES

Figure 3-1. CACR Uniform Rate of Progress 3-2

Figure 3-2. UPBU Uniform Rate of Progress 3-2

Figure 5-1. CACR Monitored Observations Compared to Uniform Rate of Progress 5-1

Figure 5-2. UPBU Monitored Observations Compared to Uniform Rate of Progress 5-2

Figure 6-1. EPA Estimated Cost Effectiveness for SDA for Independence Units 1 and 2, Revised to Consider a Shortened Remaining Useful Life 6-3

LIST OF TABLES

Table 4-1. Independent Summary of Monitoring Data for January 1, 2016 through July 31, 2016 4-1

Table 4-2. Summary of Annual Average Haze Index Values from 2002 through 2016 4-1

Table 5-1. 2016 Observed Haze Index Values Compared to 2018 URPs and RPGs 5-2

1. EXECUTIVE SUMMARY

This report provides an update to the monitoring information originally provided by Entergy Arkansas, Inc. (EAI) and Trinity Consultants (Trinity) on August 7, 2015[1] and updated on November 15, 2016[2], and analyzes Reasonable Progress for the Regional Haze Program's first planning period (ending in 2018) – specifically addressing the controls that would be needed to meet the emission limits for EAI's Independence units in the final Arkansas Regional Haze Federal Implementation Plan (FIP).[3]

The Interagency Monitoring of Protected Visual Environments (IMPROVE) has established a network of monitoring stations at mandatory Federal Class I areas across the country to measure and record visibility parameters from the atmosphere, such as sulfate and nitrate particles. From this monitoring data, visibility impairment, or haze, is determined. As of the date of this report, the most recent annual summary available is for calendar year 2015. Though the complete dataset and summary for 2016 is not yet available, un-summarized monitoring data up to July 31, 2016 are available. From this, current visibility conditions can be derived.

As presented in this report, visibility at the Class I areas in Arkansas – Caney Creek Wilderness Area (CACR) and Upper Buffalo Wilderness Area (UPBU) – has improved at a rate faster than necessary to maintain the Uniform Rate of Progress (URP) towards the Regional Haze Program goal of elimination of manmade visibility impairment by 2064. The monitoring data demonstrate that visibility improvement at these Class I areas currently exceeds EPA's goals for the first planning period even though the majority of the emission controls prescribed by the FIP have yet to be installed. The same can be said of the two Class I areas in Missouri – Mingo Wilderness Area (MING) and Hercules-Glades Wilderness Area (HEGL) – as documented in Missouri's Five-Year Progress Report to EPA.[4]

The FIP mandates NO_X and SO_2 emission limits for EAI's Independence units 1 and 2 to achieve reasonable progress towards the Regional Haze Program goal. However, due to the current and forecasted status of visibility in the Class I areas, the planned compliance strategies for Best Available Retrofit Technology (BART) requirements (*e.g.*, the cessation of coal burning at EAI's White Bluff facility in 2028),[5] implementation of other Clean Air Act (CAA) programs such as the

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[1] Trinity Consultants, *Regional Haze Modeling Assessment Report – Entergy Arkansas, Inc. – Independence Plant*, August 7, 2015 (Trinity Project No. 154401.0074), submitted as an Exhibit C to Entergy Arkansas, Inc.'s *Comments On the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas*.

[2] Trinity Consultants, *Assessment of Recent Class I Area IMPROVE Monitoring Data*, November 15, 2016 (Trinity Project No. 163701.0059).

[3] Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule, 81 Fed. Reg. 66,332 – 66,421 (September 27, 2016).

[4] State of Missouri Regional Haze 5-Year Progress Report (https://dnr.mo.gov/env/apcp/reghaze/complete-RegionalHaze-5-yr-Rpt-submittal.pdf), August 29, 2014, p. 17.

[5] The emissions control technologies on which the BART SO_2 and NO_X emissions limits are based are identified in Appendix C. Certain of the units subject to the FIP also intend to install NO_X emissions controls to meet CSAPR. For example, EAI is planning to install low NO_X burners and separated overfire air at White Bluff and Independence to comply with CSAPR's ozone season NO_X program.

Cross State Air Pollution Rule (CSAPR), and considering the four reasonable progress factors[6] (including EAI's proposed cessation of coal use at Independence by 2030 as part of resolving the 8th Circuit Court of Appeals FIP litigation), the emission limits required by the FIP for EAI's Independence units 1 and 2 are not necessary.

[6] EAI asserts that consideration of these factors is not necessary with respect to Arkansas' sources for the first planning period. However, without waiver, the four factors are addressed herein to provide a more comprehensive evaluation of reasonable progress for Arkansas' Class I areas.

2. INTRODUCTION TO VISIBILITY AND HAZE INDEX

Visibility is most simply measured as the farthest distance that can naturally be seen by an average human. Light waves diffract and are absorbed as they pass through and around particles and molecules in the atmosphere. The level of visibility therefore naturally decreases at greater distances as light waves come into contact with a greater number of these miniscule obstacles. This natural scattering of light waves is called Rayleigh scattering. Additionally, both anthropogenic (manmade) and non-anthropogenic sources of pollution, which result in increased atmospheric concentrations of particles and molecules, have an effect on visibility. The primary contributors to visibility impairment or "light extinction" include sulfates, nitrates, organic carbon, elemental carbon, crustal material, and sea salt."[7,8] Through the Interagency Monitoring of Protected Visual Environments (IMPROVE) program, concentrations of these species are monitored at each mandatory Federal Class I area[9] every three (3) days for 24 hours. The species concentrations are converted to light extinction using the Revised IMPROVE Equation:[10,11]

Equation 1. Revised IMPROVE Equation

$$
\begin{aligned}
b_{ext} = 2.2\ & \times f_S(RH) \times [Small\ Sulfate] \\
& + 4.8 \times f_L(RH) \times [Large\ Sulfate] \\
& + 2.4 \times f_S(RH) \times [Small\ Nitrate] \\
& + 5.1 \times f_L(RH) \times [Large\ Nitrate] \\
& + 2.8 \times [Small\ Organic\ Mass] \\
& + 6.1 \times [Large\ Organic\ Mass] \\
& + 10 \times [Elemental\ Carbon] \\
& + 1 \times [Fine\ Soil] \\
& + 1.7 \times f_{SS}(RH) \times [Sea\ Salt] \\
& + 0.6 \times [Coarse\ Mass] \\
& + Rayleigh\ Scattering\ (Site\ Specific) \\
& + 0.33 \times [NO_2(ppb)]
\end{aligned}
$$

Where b_{ext} represents the light extinction coefficient in inverse megameters (Mm^{-1}), and individual species concentrations are shown in brackets with units of micrograms per cubic meter ($\mu g/m^3$). The f_L and f_S terms are unitless water growth factors given as functions of relative humidity (RH) for concentrations of large and small sulfates and nitrates, while f_{SS} represents the water growth factor for sea salt concentrations. The numerical constants given in the equation (e.g., 2.2) represent

[7] U.S. EPA, *Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress*. EPA-452/R-01-008. Chapter 1 – Introduction to Visibility Issues. November 2001.

[8] Kumar, Naresh, et al. "Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data." Journal of the Air & Waste Management Association JAWMA 57.11 (2007): 1326-336.

[9] Mandatory Federal Class I areas included all international parks (IP), national wilderness areas exceeding 5,000 acres, national memorial parks exceeding 5,000 acres, and national parks exceeding 6,000 acres, in existence on August 7, 1977, and are listed, by state, in 40 Code of Federal Regulations §§81.401 – 437.

[10] In 1999, an equation to estimate light extinction based on available IMPROVE data was incorporated into the Regional Haze Rule (Old IMPROVE Equation). In 2007, a revised equation was developed to reduce "bias for high and low light extinction extremes" and to make the equation "more consistent with the recent atmospheric aerosol literature (Revised IMPROVE Equation).

[11] U.S. EPA, *Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress*. EPA-452/R-01-008. Chapter 1 – Introduction to Visibility Issues. November 2001.

dry mass extinction efficiency terms in units of square meters per gram (m^2/g).[12] Measurements and calculated light extinction values are published by IMPROVE on a Colorado State University webpage.[13]

Because the units for light extinction (Mm^{-1}) are difficult to conceptualize and compare in practical terms, the haze index (deciview or dv) was developed. The haze index is calculated as a function of the ratio of the calculated light extinction coefficient to the approximate average extinction value due to Rayleigh scattering alone (10 Mm^{-1}).

Equation 2. Formula for Haze Index (dv)

$$Haze\ Index\ (dv) = 10 \times \ln\left(\frac{b_{ext}\ [Mm^{-1}]}{10\ [Mm^{-1}]}\right)$$

The deciview scale provides a simpler representation of visibility deterioration, with natural conditions having a calculated haze index of approximately zero deciviews, depending on the site-specific level of Rayleigh scattering.[14] The larger the haze index, the more degradation of visibility at a particular location. According to EPA, a one-deciview change represents a "small but noticeable change in haziness".[15] Other studies, however, have suggested that a "1-deciview change never produces a perceptible change in haze."[16]

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[12] Kumar, Naresh, et al. "Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data." Journal of the Air & Waste Management Association JAWMA 57.11 (2007): 1326-336.

[13] IMPROVE. Regional Haze Rule Summary data through 1988-2015. (http://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx)

[14] U.S. EPA, *Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress*. EPA-452/R-01-008. Chapter 1 – Introduction to Visibility Issues. November 2001.

[15] Regional Haze Regulations; Final Rule, 64 Fed. Reg. 35,725 - 35,727 (July 1, 1999).

[16] Ronald C. Henry, "Just-Noticeable Differences in Atmospheric Haze," Journal of the Air & Waste Management Association, Vol. 52 at 1,238 (October 2002).

3. REGIONAL HAZE RULE

Section 169A of the Clean Air Act (CAA) requires implementation plans which address visibility protection for federal Class I areas to include "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal" of elimination of manmade visibility impairment at such areas.[17] To effectuate the CAA's national visibility goal, EPA promulgated the Regional Haze Rule, which has as its own goal to achieve natural visibility conditions in each Class I area by 2064.[18] There are two federal Class I areas located in Arkansas for which measures are required to make reasonable progress: Caney Creek Wilderness Area (CACR) and Upper Buffalo Wilderness Area (UPBU).

When tracking the progress of remedying visibility impairment at a particular Class I area based on measured data, EPA recommends taking the average of the haze indices, in deciviews, associated with the 20 percent most impaired days of the year (*i.e.*, "20 percent worst") and the 20 percent least impaired days of the year (*i.e.*, "20 percent best").[19] To achieve the goal, the average haze index for the 20 percent worst days must improve to meet the level of the 20 percent best days, and the 20 percent best days value must not degrade.[20]

A "glidepath" from the 20 percent worst days average to the 20 percent best days average is defined for each Class I area. It is called the Uniform Rate of Progress ("URP"). The URP is a straight line from baseline visibility conditions (average 20 percent worst days as of 2004) to natural visibility conditions (to be achieved in 2064 for the 20 percent worst days). The slope of that line is the difference between the two conditions divided by the 60-year program. The URPs for CACR and UPBU are presented in Figure 3-1 and Figure 3-2, respectively.

In addition to establishing URPs for each Class I area, as part of each state's Long Term Strategy, states (or EPA) also establish Reasonable Progress Goals (RPGs) for each area for the end of each planning period, i.e., 2018, 2028, and so on. The 2018 RPGs set by EPA for the Arkansas Class I areas are 22.47 dv for CACR and 22.51 dv for UPBU.[21]

[17] 42 U.S.C. § 7491(b)(2).
[18] Regional Haze Regulations; Final Rule, 64 Fed. Reg. 35,732 and 35,766 (July 1, 1999).
[19] Regional Haze Regulations; Final Rule, 64 Fed. Reg. 35.728 and 35,730 (July 1, 1999).
[20] Regional Haze Regulations; Final Rule, 64 Fed. Reg. 35.730 and 35,734 (July 1, 1999).
[21] Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule, 81 Fed. Reg. 66,354 (September 27, 2016).

Figure 3-1. CACR Uniform Rate of Progress

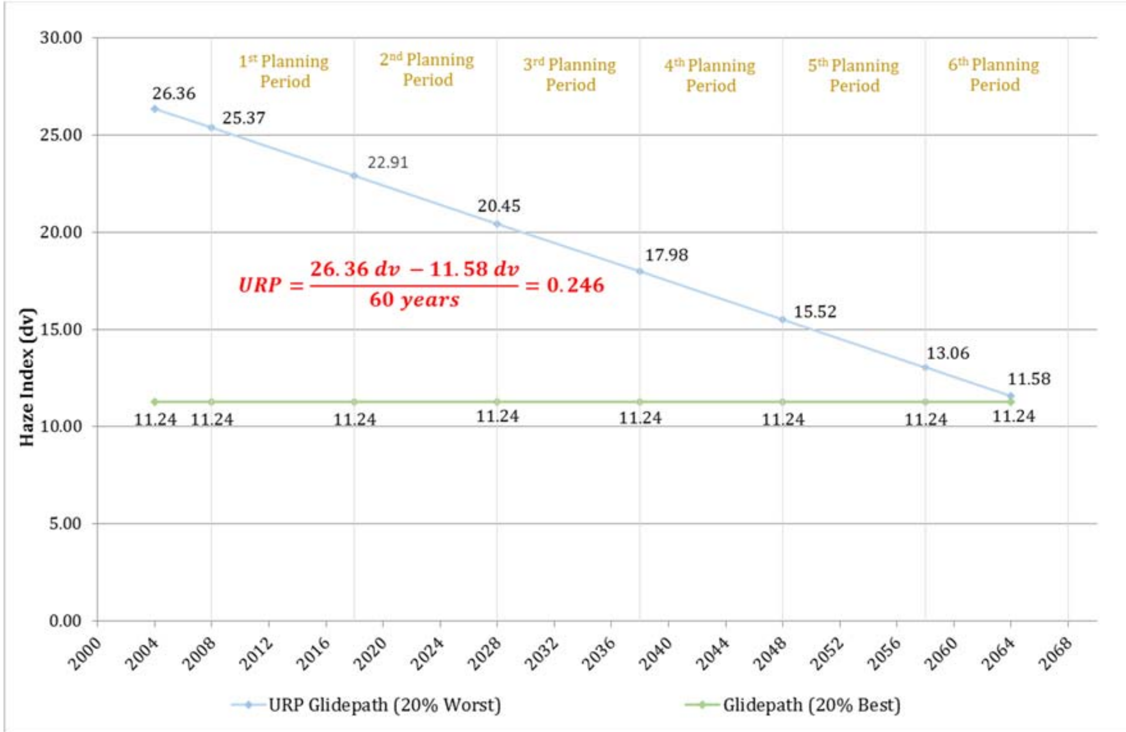
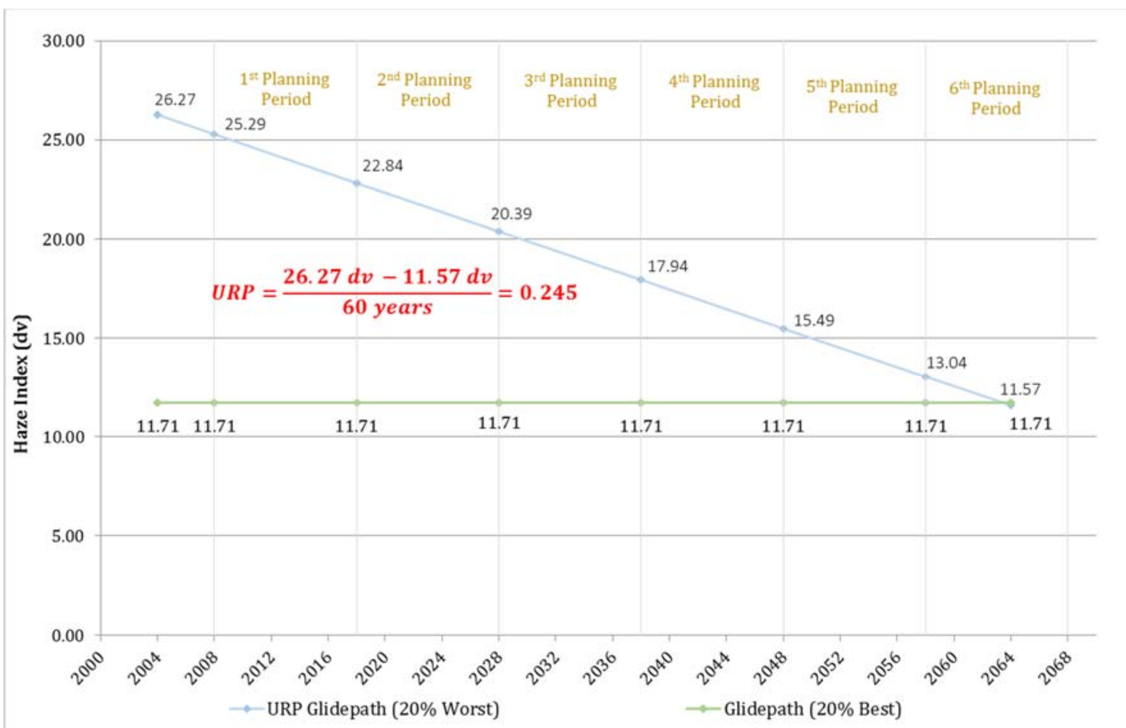


Figure 3-2. UPBU Uniform Rate of Progress



4. RECENT IMPROVE MONITORING DATA

The most recent and complete summary of annual monitoring data available from IMPROVE for CACR and UPBU covers the year 2015. However, as of the date of this report, non-summarized data through July 31, 2016, is available and can be used to calculate the light extinction coefficients (see Equation 1) and haze indices (see Equation 2) for January through July of 2016. Trinity obtained the non-summarized data and compiled an independent summary for January through July of 2016.[22] The species-specific and total light extinction and haze index values for the averages of the 20 percent worst days and the 20 percent best days for the first half of 2016 are shown in Table 4-1.

Table 4-1. Independent Summary of Monitoring Data for January 1, 2016 through July 31, 2016

	20 Percent Worst Days Average		20 Percent Best Days Average	
Light Extinction Value (Mm^{-1})	**CACR**	**UPBU**	**CACR**	**UPBU**
Sulfate	31.46	28.84	4.72	4.80
Nitrate	16.86	21.03	1.04	1.17
Organics	18.49	17.81	2.21	2.31
Carbon	2.96	3.58	0.32	0.38
Soil	3.20	2.78	0.10	0.10
Coarse PM	6.78	6.86	1.41	1.20
Sea Salt	1.12	0.81	0.06	0.06
Total Light Extinction (Mm^{-1})	74.30	72.85	24.75	26.72
Haze Index (dv)	**19.90**	**19.67**	**8.83**	**9.67**

Table 4-2 presents a summary of the annual-average haze index values for each year from 2002 to 2016 (based on first half of the year).[23]

Table 4-2. Summary of Annual Average Haze Index Values from 2002 through 2016

	20 Percent Worst Days Average		20 Percent Best Days Average	
Year	**CACR**	**UPBU**	**CACR**	**UPBU**
2002	27.21	26.74	11.88	12.83
2003	26.54	27.22	10.74	10.62
2004	25.34	25.58	11.11	10.74
2005	29.21	30.47	12.93	13.34
2006	25.68	25.42	12.51	13.00
2007	--	26.17	--	12.45
2008	23.70	24.60	9.24	10.49
2009	22.68	22.62	8.09	9.40
2010	22.94	--	10.76	--
2011	22.67	23.21	11.71	11.51
2012	21.49	21.56	9.54	10.31
2013	21.35	21.25	8.61	8.60
2014	20.72	20.49	8.52	8.13
2015	20.41	19.96	7.03	7.50
2016	19.90	19.67	8.83	9.67

[22] The calculations and data summarizing method were confirmed by downloading and processing the un-summarized data for 2014 and then comparing the results to the values in the 2014 summary found online.
[23] Summarized data are not available for CACR for 2007, UPBU for 2010, and MING for 2002 through 2005.

5. MONITORING DATA COMPARED TO REGIONAL HAZE GOALS

Figure 5-1 and Figure 5-2 present, for CACR and UPBU, respectively, comparisons of the observed haze index values (*see* Section 4) for each year of IMPROVE data, including values from the first half of 2016, to the URPs (*see* Section 3). The same comparisons are shown for the two Missouri Class I areas in Appendix B.

Figure 5-1. CACR Monitored Observations Compared to Uniform Rate of Progress

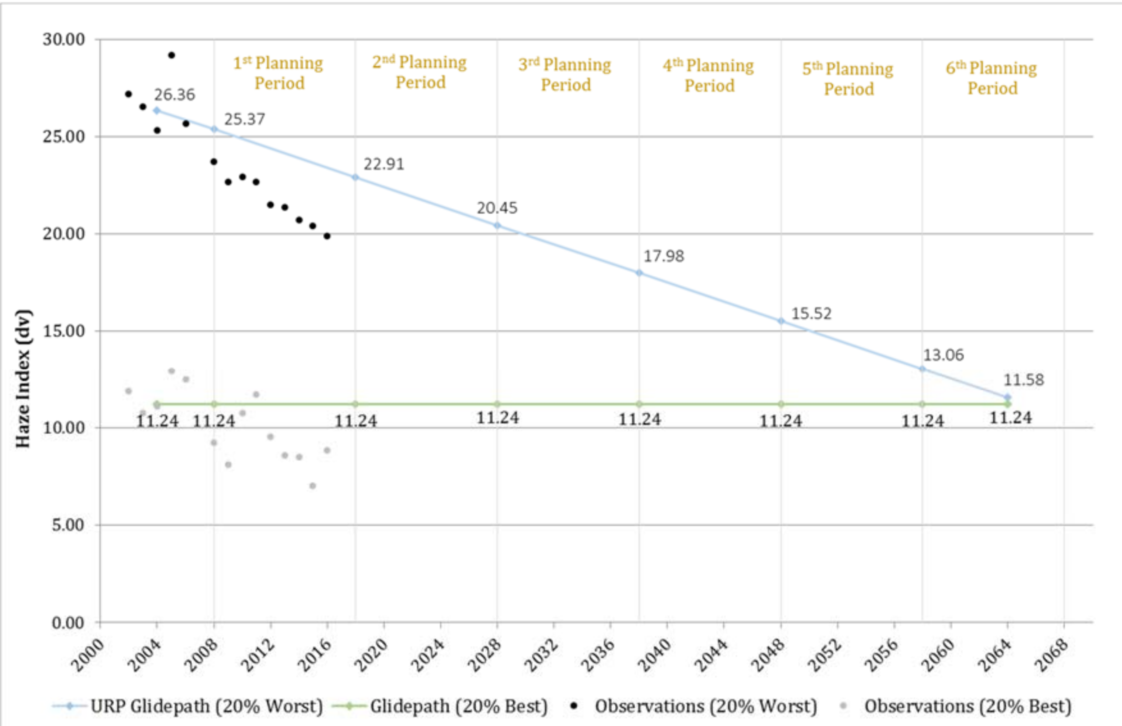
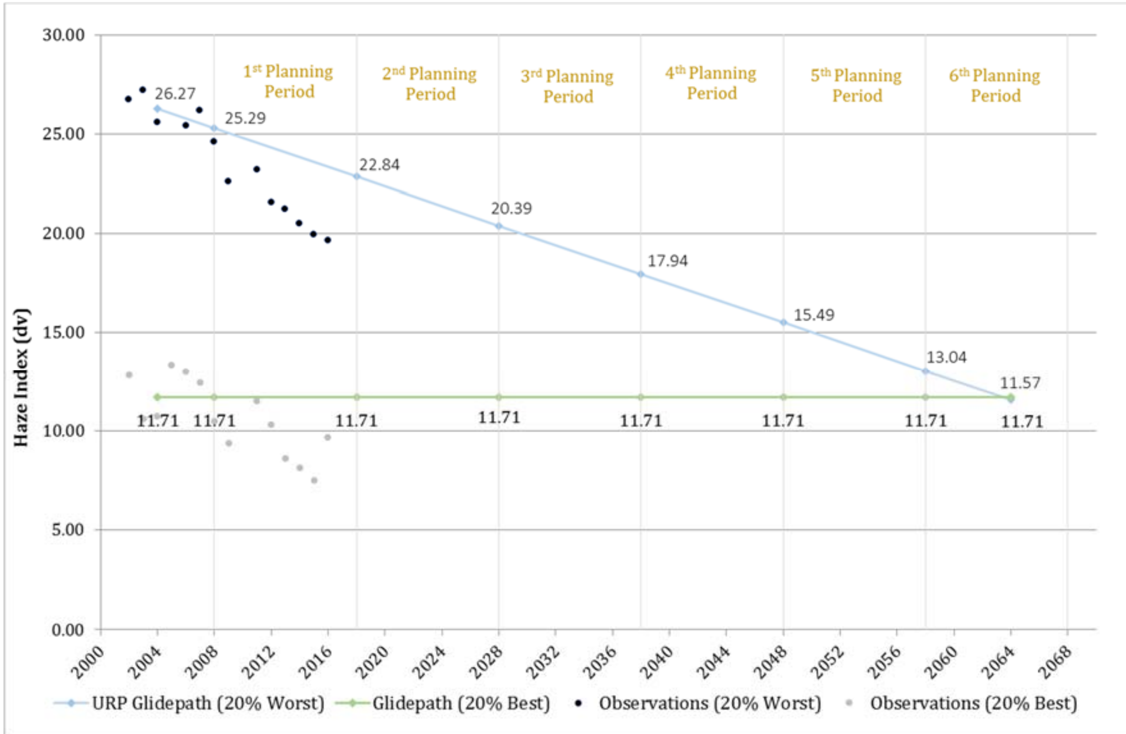


Figure 5-2. UPBU Monitored Observations Compared to Uniform Rate of Progress



As seen in the figures above, the actual visibility impairment, measured as the average of the 20 percent worst days each year, at these Class I areas has declined sharply from 2002 through July of 2016 (the most recent available data). According to the monitor data, the current (January through July 2016) observed 20 percent worst days average haze index values are below the URP values for 2018 as well as the 2018 RPG values. Table 5-1 presents a comparison of the 2016 observed values and the 2018 RPG values.

Table 5-1. 2016 Observed Haze Index Values Compared to 2018 URPs and RPGs

Class I Area	Observed 20 Percent Worst Days Average for 2016 (first half year)	RPG for 2018	Observed Value as % of RPG
CACR	19.90	22.47	88.6 %
UPBU	19.67	22.51	87.4 %

6. REGIONAL HAZE REQUIREMENTS FOR FIRST PLANNING PERIOD

The visibility improvement in the Class I areas that are presented in previous sections of this report have been achieved without installation of any controls for BART or Reasonable Progress at Arkansas' point sources during the time period covered by the visibility index values presented above. Appendix C identifies the emissions control technologies on which the FIP's BART emissions limits are based. To meet the emission limits determined to represent reasonable progress towards the national visibility goal for the first planning period under the FIP, Independence must install NO_X controls by April 27, 2018, and SO_2 controls by October 27, 2021.[24] However, these controls are clearly unnecessary to maintain the URP during the first planning period. Visibility improvement is already on an accelerated pace such that the rate of progress towards the national visibility goal exceeds the uniform rate necessary to remedy visibility impairment at CACR and UPBU by 2064. Given the visibility conditions and the Arkansas sources' ongoing environmental compliance strategies across the CAA programs, it should be concluded that no further measures are necessary for Arkansas to make reasonable progress toward the Regional Haze Program national goal in the first planning period.

This conclusion is consistent with EPA's own guidance to the states, which advises a long-term view of reasonable progress: "you should take into account the fact that the long-term goal of no manmade impairment encompasses several planning periods. It is reasonable for you to defer reductions to later planning periods in order to maintain a consistent glidepath toward the long-term goal."[25] Also, "[g]iven the significant emissions reductions that we anticipate to result from BART…and other Clean Air Act programs…it may be all that is necessary to achieve reasonable progress in the first planning period for some States."[26]

Specifically, the Reasonable Progress emission limits in the FIP--which would require the installation of Spray Dry Absorbers (SDA) on EAI's Independence units 1 and 2--are unnecessary for Arkansas to make reasonable progress toward meeting the national goal in the first planning period. EPA's primary justification for proposing Reasonable Progress limits at Independence is that "it would be unreasonable to ignore a source representing more than a third of the State's SO_2 emissions and a significant portion of NO_X point source emissions."[27] EPA further supports its conclusion that emission limits based on the installation of major control technology are justified based on a finding that the proposed controls at Independence are cost effective.[28] However, the fact that a source may have significant emissions, or that it would be cost effective to control such

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[24] Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule, 81 Fed. Reg. 66,332 - 66,421 (September 27, 2016). The SO_2 compliance date was reiterated by EPA on September 11, 2017, in 82 Fed. Reg. 42,639. EPA proposed to extend the NO_X compliance deadline by 21 months to January 27, 2020, in 82 Fed. Reg. 32,284 (July 13, 2017).

[25] U.S. EPA, *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*, June 1, 2007, p. 1-4.

[26] Ibid, p. 4-1.

[27] Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule, 81 Fed. Reg. 18,992 (September 27, 2016).

[28] Ibid, pp. 18,994-97. As noted in EAI's comments on the Proposed FIP, however, EPA's cost calculations substantially underestimated the costs to install dry scrubbers at Independence and an accurate estimate of the costs would have rendered the controls not cost effective for reasonable progress purposes. Entergy Arkansas, Inc. Comments on the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas, at 44 (Aug. 7, 2015), EPA Docket No. EPA-R06-OAR-2015-0189-0166 ("EAI Comments").

emissions, is irrelevant for Reasonable Progress purposes for the reasons stated above. Moreover, as discussed below, the FIP-required emission limits at Independence--allegedly established to achieve reasonable progress for the first planning period despite that fact that visibility at Arkansas' Class I areas is already better than EPA's own RPGs for that period--are unreasonable in consideration of the four statutory factors for evaluating the feasibility of reasonable progress requirements.[29]

A. **The non-air quality environmental impacts of SDA at Independence.** Non-air quality environmental impacts of SDA primarily relate to available water resources and waste byproducts. SDA systems consume a significant quantity of water, and the required water must be relatively clean. In addition, SDA systems also generate a large waste byproduct stream, containing calcium salts, which must be landfilled. If not fixated during the disposal process, the calcium salts are soluble and may dissolve and appear in the landfill leachate.

B. **The cost of compliance, time necessary for compliance, and remaining useful life (RUL) of the Independence coal units.** As part of resolving the 8th Circuit FIP appeal litigation, Entergy proposes to cease to combust coal at the Independence units by the end of 2030. When the coal units' RUL is properly considered along with the time necessary for compliance with the SO_2 emission limit (*e.g*. the 5-year compliance deadline in the FIP), the costs of compliance for each unit are approximately $4,000/ton of SO_2 removed according to EPA's own cost estimates.[30] These costs are not reasonable or cost-effective.

   Figure 6-1 presents cost effectiveness values for SDA for the Independence units calculated using the spreadsheet developed by EPA for the FIP[31], revised to reflect a 9-year equipment life. The 9-year life is based on a 2030 date for the end of the coal-burning life and, conservatively, on the FIP's compliance date of 2021.[32]

[29] 42 U.S.C. § 7491(g)(1). EAI asserts that consideration of these factors is not required because no further measures are necessary for Arkansas to make reasonable progress toward the Regional Haze Program national goal during the first planning period. However, without waiver, the four factors are addressed herein to provide a more comprehensive evaluation of reasonable progress for Arkansas' Class I areas.

[30] All cost values in this report are presented solely for the purpose of this report and without waiving previously documented positions regarding proper cost estimating methods and inputs. *See* EAI Comments at 7-11.

[31] "White Bluff_R6 cost revisions2-revised.xlsx" from EPA Docket EPA-R06-OAR-2015-0189-0205. Before revising the equipment life value, the cost effectiveness ($/ton) results matched the values presented in the final FIP: $2,853/ton and $2,634/ton for Unit 1 and Unit 2, respectively.

[32] Considering the current state of the FIP and the replacement SIP that Arkansas is developing, a more realistic compliance date would be 2023 – five years from an anticipated final approval of the SIP in 2018. The five-year compliance timeline is the minimum necessary for engineering, procuring, installing, and commissioning a SDA.

Figure 6-1. EPA Estimated Cost Effectiveness for SDA for Independence Units 1 and 2, Revised to Consider a Shortened Remaining Useful Life

Independence Unit 1

Item	Corrected White Bluff Cost to 0.68 lbs/MMBtu	Comments
Total Annualized Cost	$54,903,656	Assumed same as White Bluff Unit 1
Interest Rate (%)	7	
Equipment Lifetime (years)	9	
Capital Recovery Factor (CRF)	0.1535	
SO2 Emission Rate (lbs/MMBtu)	0.63	Max monthly value from 2009-2013 for Unit 1
Controlled SO2 Emission Rate (%)	90.49	Assume 95%. If outlet < 0.06 lbs/MMBtu, then assume % control for 0.06 lbs/MMBtu.
SO2 Emission Baseline (tons)	14,269	3 -yr avg. 2009-2013 for Unit 1, excluding max and min
SO2 Emission Reduction (tons)	12,912	
Cost Effectiveness ($/ton)	$4,252	

Independence Unit 2

Item	Corrected White Bluff Cost to 0.68 lbs/MMBtu	Comments
Total Annualized Cost	$54,903,656	Assumed same as White Bluff Unit 1
Interest Rate (%)	7	
Equipment Lifetime (years)	9	
Capital Recovery Factor (CRF)	0.1535	
SO2 Emission Rate (lbs/MMBtu)	0.61	Max monthly value from 2009-2013 for Unit 2
Controlled SO2 Emission Rate (%)	90.19	Assume 95%. If outlet < 0.06 lbs/MMBtu, then assume % control for 0.06 lbs/MMBtu.
SO2 Emission Baseline (tons)	15,511	3 -yr avg. 2009-2013 for Unit 2, excluding max and min
SO2 Emission Reduction (tons)	13,990	
Cost Effectiveness ($/ton)	$3,925	

(red text reflects revised equipment life values; no other inputs or equations/cell-references were changed; yellow-highlighting is original to EPA's spreadsheet;)

A. **The minimal contribution that the Independence units – and Arkansas point sources in general – have on visibility impacts in the Class I areas.** As documented in EAI's comments on the proposed FIP[33] and further explained in Appendix A to this report, the emissions from Independence are one of many factors contributing to haze at Arkansas' Class I areas but have only a minimal impact on visibility impairment. Therefore, emissions controls at Independence would have no discernable impact on visibility.

[33] *See* EAI Comments at 17-43.

7. LONG TERM STRATEGY CONSIDERATIONS

Visibility impairment has steadily declined throughout the first planning period. The reductions in visibility-impairing emissions have occurred across nearly the entire spectrum of source types – from point sources to areas sources and mobile sources. It is expected that further improvements will be more difficult as visibility impairment values move closer to natural conditions. For example, the difficulty of even quantifying improvements from area sources was recognized by EPA when it agreed not to evaluate such sources for Reasonable Progress controls in the first planning period.[34] As documented in Appendix A, the single largest source type influencing Arkansas' share of the contribution to visibility impairment is area sources (not point sources like Independence). However, planned emissions decreases, e.g., resulting from the implementation of CSAPR and the increasingly more stringent National Ambient Air Quality Standards (NAAQS)[35], should cause visibility impairment to continue to decline. The cessation of coal usage at both White Bluff in 2028 and at Independence in 2030 will supplement these decreases.

[34] Approval and Promulgation of Implementation Plans; Arkansas; Approval of Regional Haze State Implementation Plan Revision and Withdrawal of Federal Implementation Plan for NO_X for Electric Generating Units in Arkansas; Proposed Rule, 82 Fed. Reg. 42,632 (September 11, 2017).

[35] The Arkansas Department of Environmental Quality (ADEQ), in consultation with Federal Land Managers and other states, addressed additional ongoing air pollution control programs as well as mitigation of construction activities, source retirements/replacements, smoke management, and other visibility-affecting measures related to all sources – major and minor stationary sources, mobile sources, and area sources – as part of its Long Term Strategy in its September 9, 2008 *State of Arkansas Regional Haze Rule State Implementation Plan.*

APPENDIX A: ANALYSIS OF SOURCE CATEGORY AND SOURCE-SPECIFIC CONTRIBUTIONS TO CLASS I AREA VISIBILITY IMPACTS

All data presented in this Appendix were extracted from the modeled source apportionment extinction data from the Central Regional Air Planning Association (CENRAP) Particulate Matter Source Apportionment Technique (PSAT) tool. The data were organized by geographic region and source category, so that the individual contribution of each source category in each geographic region could be determined.

EPA's Reasonable Progress analysis primarily focused on point source contributions to light extinction at CACR and UPBU. As a result, EPA chose to limit its evaluation of potential Reasonable Progress controls solely to Arkansas' largest emitting point sources - specifically, to Independence. However, Arkansas point sources are relatively insignificant contributors to visibility impairment in CACR and UPBU compared to most of the other regions modeled by CENRAP and are not even the biggest source group contributor in Arkansas to visibility impairment in these Class I areas.

Figures A-1 and A-2 display the modeled percent contribution of elevated and low-level point sources to the total light extinction at CACR and UPBU from the significantly contributing geographic regions.[36] Also included in these figures is the combined total percentage contribution from all point sources in all geographic regions. As shown in the CACR figure, of a total point source contribution of 61.85 percent at CACR in 2002, Arkansas's point sources contributed only 2.87 percent, making Arkansas point sources only the eighth highest point source contributor. Similarly, of the 60.35 percent total point source contribution at UPBU in 2002, Arkansas point sources were the ninth highest point source contributor with only a 2.47 percent contribution.

[36] These figures were originally presented as Figure 3 and Figure 4 in Entergy Arkansas Inc., *Comments On the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas*, Docket No. EPA-R06-OAR-2015-0189, August 7, 2015.

Figure A-1. Regional Point Source Percentage of Total Extinction at CACR (20 Percent Worst, 2002)

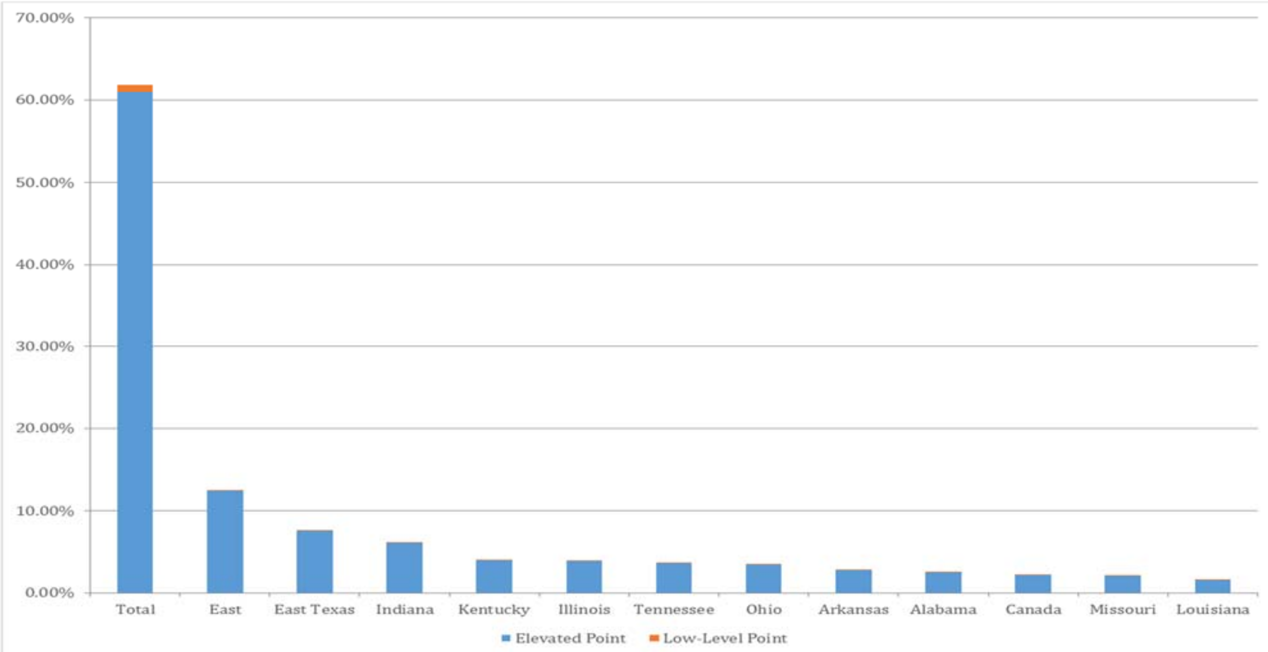
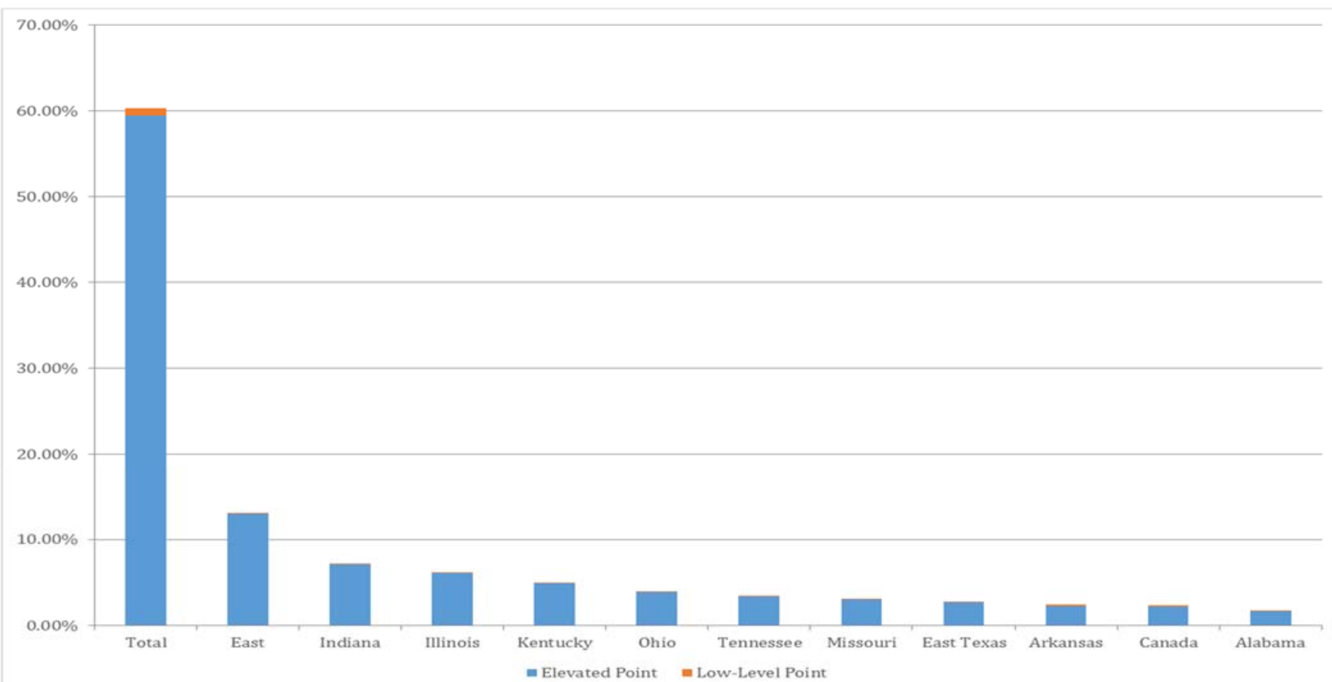


Figure A-2. Regional Point Source Percentage of Total Extinction at UPBU (20 Percent Worst, 2002)



In addition, as demonstrated in Figures A-3 and A-4 below, most of Arkansas' share of the contribution to visibility impairment comes from area and mobile sources, not point sources.[37] At

[37] These figures were originally presented as Figure 5 and Figure 6 in Entergy Arkansas Inc., *Comments On the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas*, Docket No. EPA-R06-OAR-2015-0189, August 7, 2015.

CACR, Arkansas area sources contribute 3.75 percent of the overall extinction and Arkansas' combined point source category (*i.e.*, elevated and low-level point sources) contributes only 2.87 percent. Even more significantly, Arkansas area sources contributed 5.09 percent towards extinction at UPBU compared to 2.47 percent from the combined Arkansas point sources.

Figure A-3. Regional Percentage of Total Extinction at CACR (20 Percent Worst, 2002)

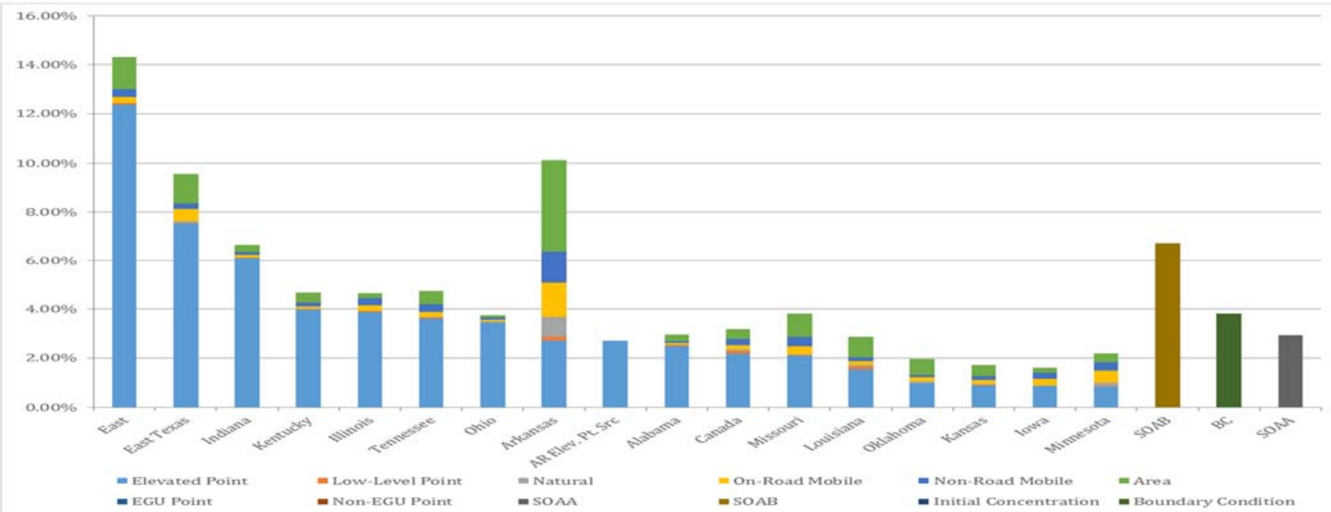
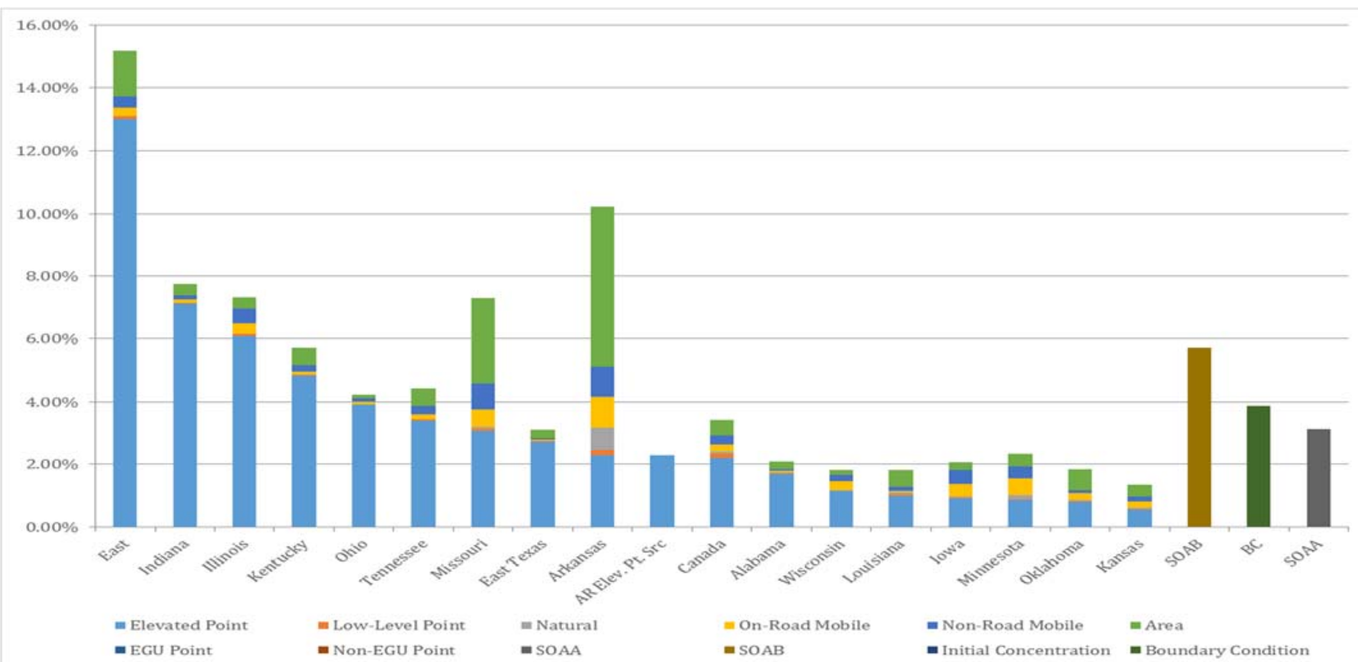


Figure A-4. Regional Percentage of Total Extinction at UPBU (20 Percent Worst, 2002)



On a source-specific (Independence-only) basis, the contribution is even smaller. CENRAP's predictive modeling demonstrates that sulfate from all (elevated and low level) Arkansas point sources is responsible for 3.58 percent of the total light extinction at CACR and 3.20 percent at UPBU; and nitrate from Arkansas point sources is responsible for 0.29 percent of the total light extinction at CACR and 0.25 percent at UPBU.[38] The Independence units' share of emissions to this minimal contribution from Arkansas point sources to visibility impairment is even less. EAI and Trinity submitted CAMx modeling showing that the contribution to visibility impairment by Independence is less than one half of one percent of the visibility impairment in both Arkansas Class I areas.[39]

[38] Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule, 81 Fed. Reg. 18,990 (September 27, 2016).

[39] Entergy Arkansas Inc., *Comments On the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas*, Docket No. EPA-R06-OAR-2015-0189, August 7, 2015.

APPENDIX B: OBSERVATIONS COMPARED TO UNIFORM RATES OF PROGRESS FOR MISSOURI'S CLASS I AREAS

Figure B-1. MING Monitored Observations Compared to Uniform Rate of Progress

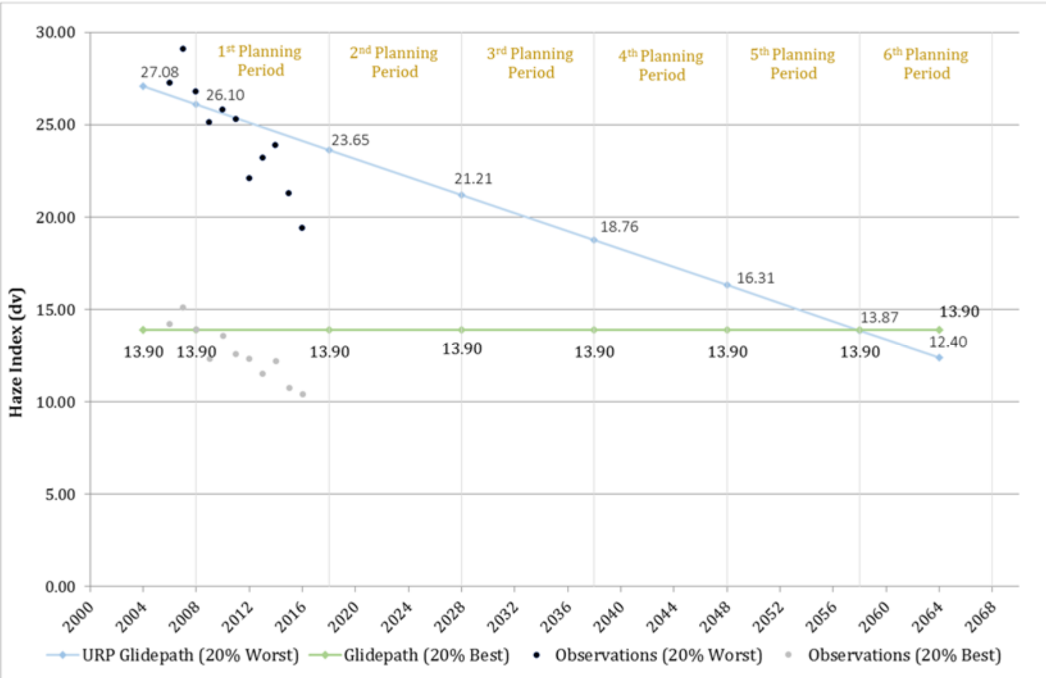
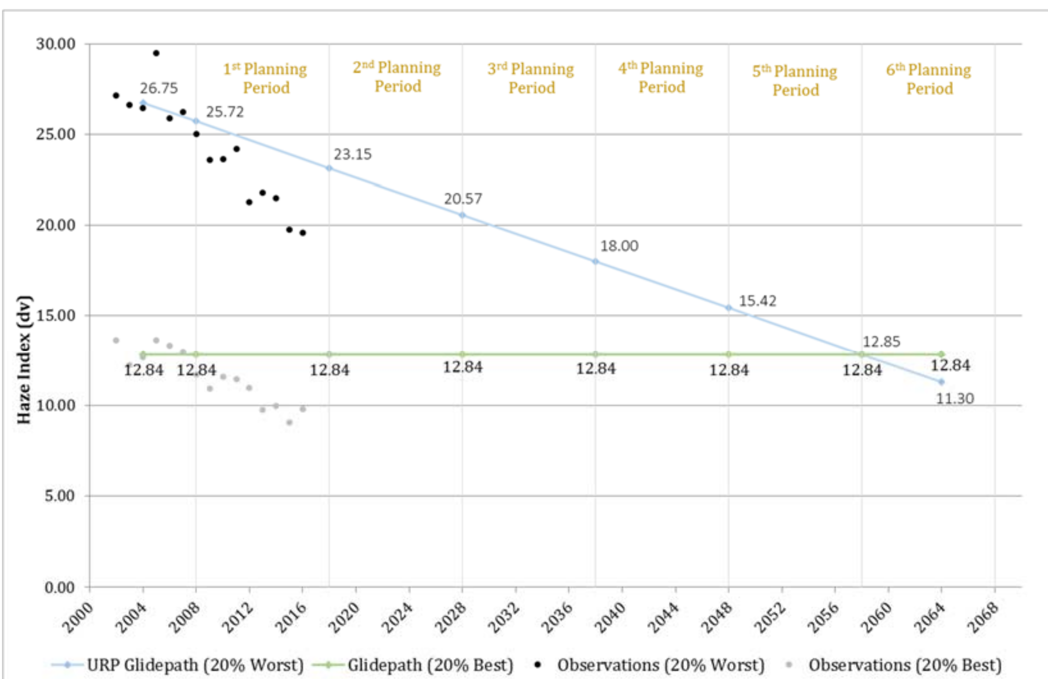


Figure B-2. HEGL Monitored Observations Compared to Uniform Rate of Progress



APPENDIX C: CONTROLS ON WHICH THE BART EMISSIONS LIMITS ARE BASED

The FIP's BART emission limits are based on the following emissions control technologies:[40]

Company	Facility	Unit	Controls	Compliance Deadline
AEP/SWEPCO	Flint Creek	1	Novel Integrated Desulfurization (NID)	April 27, 2018
			Low NO_X Burners & Over Fire Air (LNB/OFA)	April 27, 2018
AECC	Bailey	1	Fuel sulfur content limit	October 27, 2021
AECC	McClellan	1	Fuel sulfur content limit	October 27, 2021
EAI	White Bluff	1	Spray Dry Absorber (SDA)	October 27, 2021
			LNB/OFA	April 27, 2018
		2	SDA	October 27, 2021
			LNB/OFA	April 27, 2018
EAI	Lake Catherine	4	Burners Out Of Service (BOOS)	October 27, 2019
Domtar	Ashdown	Boiler 2	Additional scrubbing reagent	October 27, 2021
			LNB	October 27, 2021

[40] Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule, 81 Fed. Reg. 66,332 - 66,421 (September 27, 2016).