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

Entergy®

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

Submitted to:

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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.

[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.

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*

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[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.

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[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

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[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]

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[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)

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	1.533	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 $\Delta dv \geq 0.5$	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