Arkansas Regional Haze Planning Period II

State Implementation Plan

CHAPTER V: REASONABLE PROGRESS ANALYSIS

Chapter V: Reasonable Progress Analysis

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V. Reasonable Progress Evaluation

The RHR at 40 C.F.R. 51.308(f)(2)(i) requires each state to "evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering the cost of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment." The RHR specifies that states should "consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area [(nonpoint)] sources."

This chapter documents the technical basis that DEQ is relying upon to determine the emission reduction measures that are necessary to make reasonable progress at each federal Class I area affected by emissions from Arkansas, consistent with the RHR at 40 C.F.R.51.308(f)(2)(iii). The additional factors the State must consider in developing its long-term strategy consistent with RHR at 40 C.F.R.51.308(f)(2)(iii) are described in Chapter VI.

A. Identification of Key Pollutants and Source Categories that Contribute to Visibility Impairment at Federal Class I Areas in Arkansas and in Other States that may be Affected by Emissions from Arkansas

EPA guidance highlights that the RHR does not require a state to evaluate all sources of emissions in each implementation period.[1] The guidance further notes that the RHR does not explicitly list the factors a state must consider when selecting sources for a reasonable progress analysis. Therefore, each state "must reasonably choose factors and apply them in a reasonable way given the statutory requirement to make reasonable progress toward natural visibility.[2] The guidance also provides that a state may "focus on the [particulate species] that dominate visibility impairment at the Class I areas affected by emissions from the state and then select only sources with emissions of those dominant pollutants and their precursors."[3] Consistent with EPA's guidance, DEQ's selection of key pollutants and source categories to evaluate for its reasonable progress analysis is based on the following factors:

- Particulate species from anthropogenic sources of emissions that dominate visibility impairment at federal Class I areas in Arkansas and those affected by emissions from Arkansas;
- Relative contributions of various sectors to the Arkansas emission inventory; and
- Projected 2028 sector-based source apportionment results from EPA's modeling.[4]

[1] EPA (2019). "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period. at page 9.
[2] *Id.* at page 10
[3] *Id.* at page 11
[4] EPA (2019). "Technical Support Document for EPA's Updated 2028 Regional Haze Modeling." https://www.epa.gov/visibility/technical-support-document-epas-updated-2028-regional-haze-modeling

1. Key Anthropogenic Particulate Species

As described in Chapters II and III, 2019 data show that visibility impairment on the most impaired days at Class I areas that are reasonably anticipated to be impacted by emissions from Arkansas sources are consistently dominated by ammonium sulfate, ammonium nitrate, or both. Both species are primarily attributable to anthropogenic sources. At Caney Creek, organic mass contributes more than ammonium nitrate. However, most of the impairment from organic mass at Caney Creek is attributable to natural sources. Elemental carbon is primarily anthropogenic in nature, but it makes up a smaller contribution to visibility impairment at the federal Class I areas described in Chapters II and III.

Table V-1 lists the key anthropogenic particulate species impairing visibility on the most impaired days for federal Class I areas described in Chapters II and III. Visibility impairment on the clearest days has remained below baseline conditions. Therefore, DEQ did not put weight on relative contributions to visibility impairment on the clearest days in its consideration of source selection for the Planning Period II reasonable progress analysis.

Table V-1: Summary of Key Anthropogenic Particulate Species

Class I area	Key Anthropogenic Particulate Species	Precursor Pollutants
Caney Creek	Ammonium Sulfate Ammonium Nitrate	Ammonia, SO_2, NOx
Upper Buffalo	Ammonium Sulfate Ammonium Nitrate	Ammonia, SO_2, NOx
Mingo	Ammonium Nitrate Ammonium Sulfate	Ammonia, SO_2, NOx
Hercules Glades	Ammonium Sulfate Ammonium Nitrate	Ammonia, SO_2, NOx
Mammoth Cave	Ammonium Sulfate Ammonium Nitrate	Ammonia, SO_2, NOx
Sipsey	Ammonium Sulfate	Ammonia, SO_2
Wichita Mountains	Ammonium Nitrate Ammonium Sulfate	Ammonia, SO_2, NOx
Shining Rock	Ammonium Sulfate	Ammonia, SO_2

Chapter IV provides detailed information about trends in emissions of the precursor pollutants listed in Table V-1 in Arkansas and directly emitted $PM_{2.5}$ (Primary $PM_{2.5}$). DEQ notes that its emission inventory of Primary $PM_{2.5}$ is not speciated and therefore includes all particulate species directly emitted rather than just ammonium sulfate and ammonium nitrate.

2. Key Anthropogenic Particulate Species and their Precursors in the Arkansas Emission Inventory

Table IV-6 in Chapter IV details trends in statewide Primary $PM_{2.5}$ emissions data between 2011 and 2017 broken out by emission sector. Figure V-1 uses the data presented in Table IV-6 to show the relative contribution of each sector to the total Primary $PM_{2.5}$ emission inventory based on the most recent NEI (2017). In 2017, 85% of Primary $PM_{2.5}$ emissions in Arkansas came from sectors that DEQ does not have the authority to regulate under Arkansas law or from which DEQ is pre-empted from regulating by EPA.

Figure V-1: Sector Contributions to the Arkansas 2017 Primary $PM_{2.5}$ Emissions Inventory

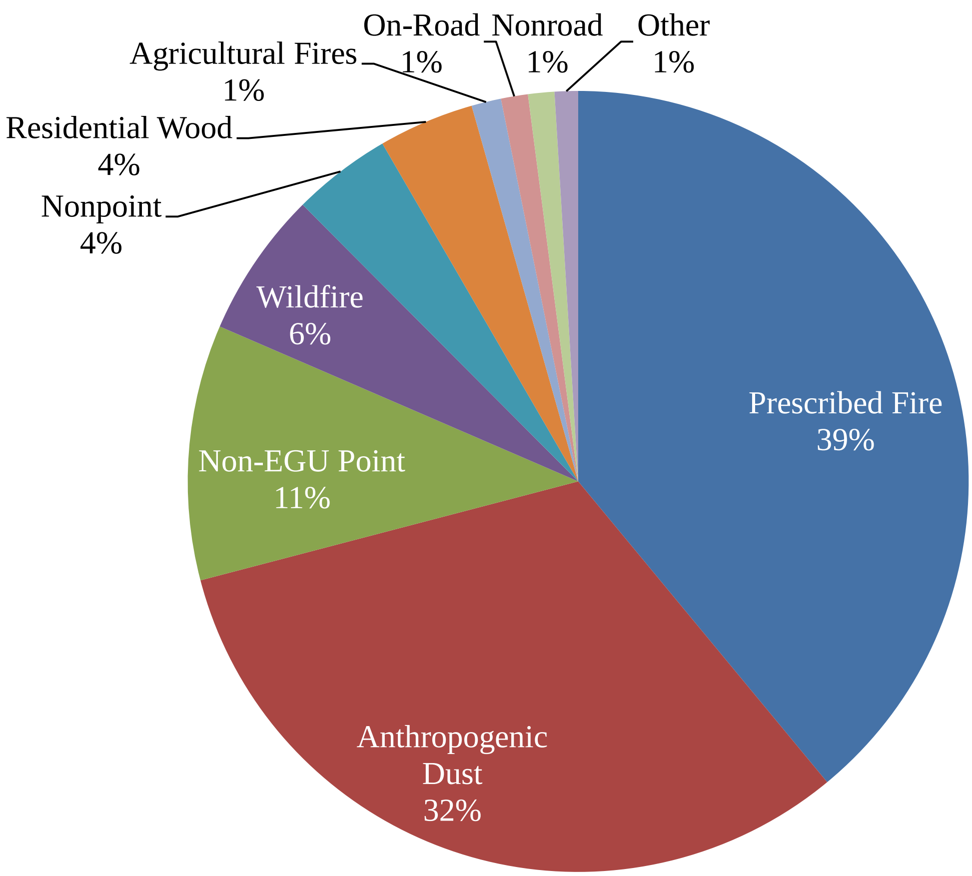


Table IV-7 in Chapter IV details trends in ammonia emissions from anthropogenic sources in Arkansas between 2011 and 2017. Figure V-2 uses the data presented in Table IV-7 to show the relative contribution of each sector to the total ammonia emission inventory based on the 2017 NEI. In 2017, 98% of ammonia emissions in Arkansas came from sectors that DEQ does not have authority to regulate under Arkansas law or from which DEQ is pre-empted from regulating by EPA. DEQ's long-term strategy does include voluntary measures to mitigate impacts from prescribed and agricultural fires.

Figure V-2: Sector Contributions to the Arkansas 2017 Ammonia Emissions Inventory

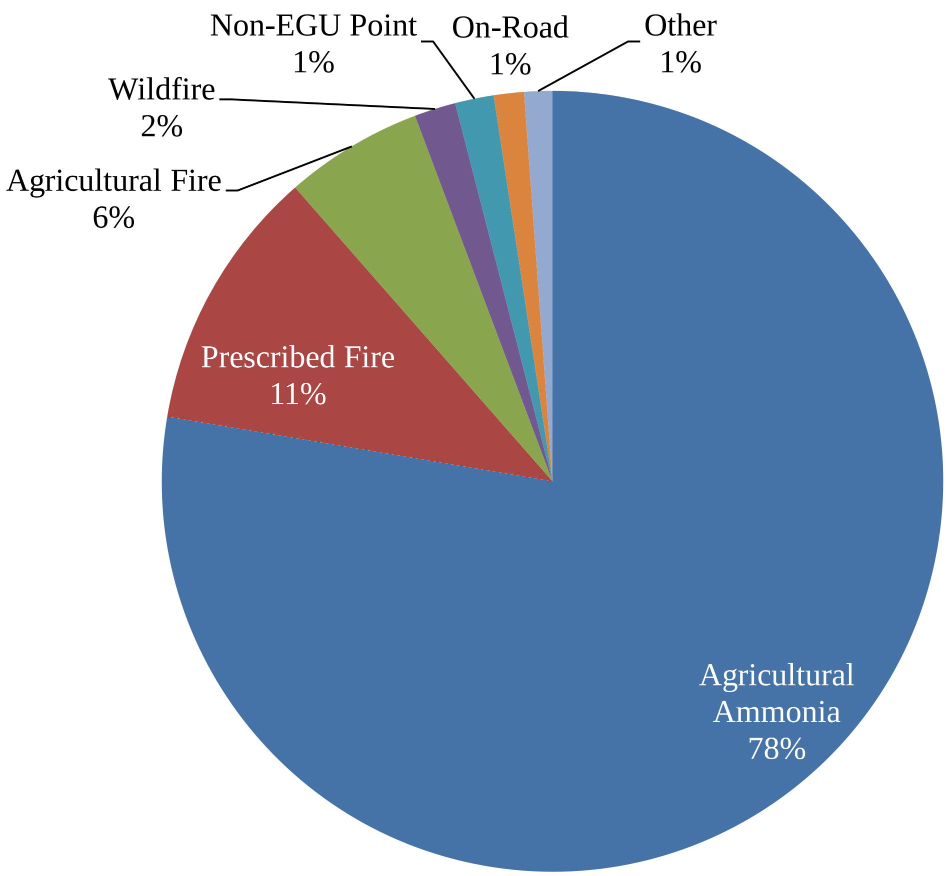


Table IV-4 in Chapter IV details trends in NOx emissions from anthropogenic sources in Arkansas between 2011 and 2017. Figure V-3 uses the data presented in Table IV-4 to show the relative contribution of each sector to the total NOx emission inventory based on the 2017 NEI. In 2017, 35% of NOx emissions in Arkansas came from sectors that DEQ has authority to regulate under Arkansas law, including larger concentrated sources, such as EGUs and Non-EGU point sources.

Figure V-3: Sector Contributions to the Arkansas 2017 NOx Emissions Inventory

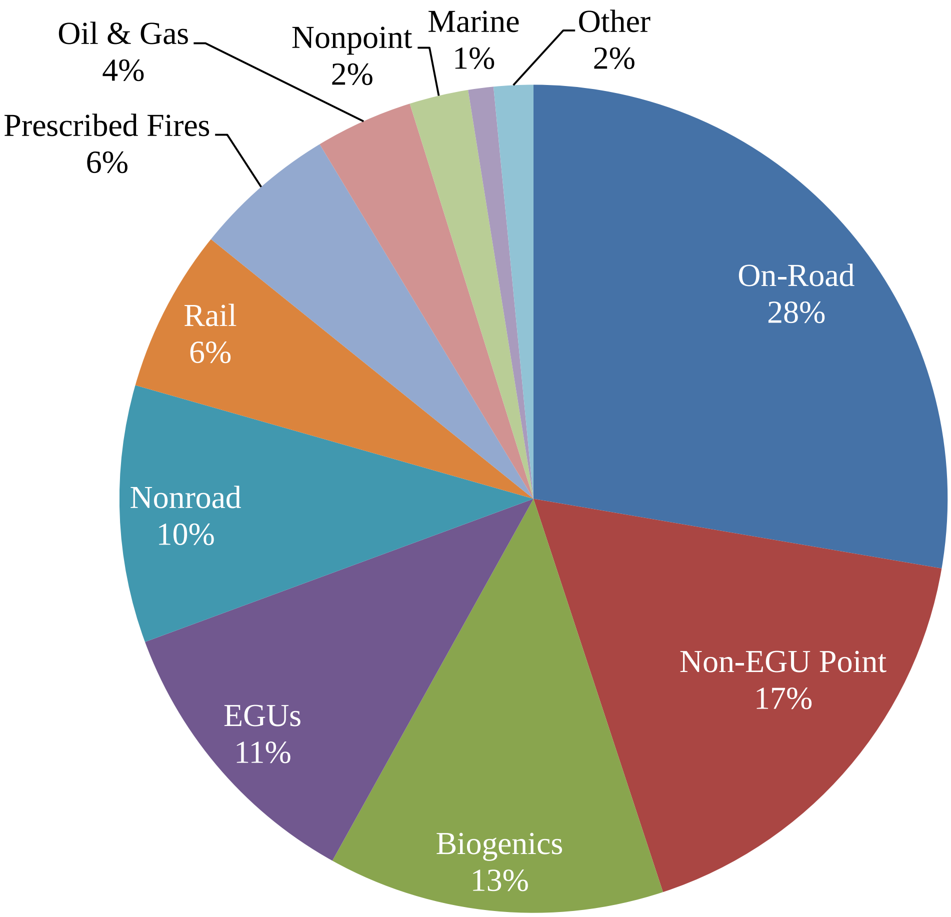
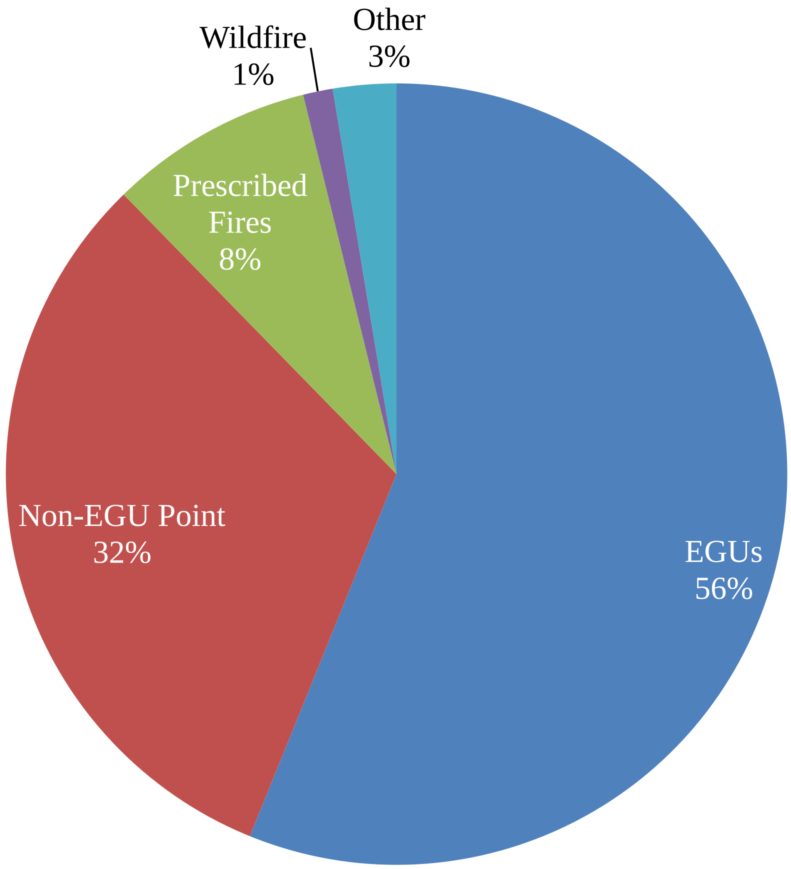


Table IV-5 in Chapter IV details trends in SO_2 emissions from anthropogenic sources in Arkansas between 2011 and 2017. Figure V-4 uses the data presented in Table IV-5 to show the relative contribution of each sector to the total SO_2 emission inventory based on the 2017 NEI. In 2017, 89% of SO_2 emissions in Arkansas came from sectors that DEQ has authority to regulate under Arkansas law, including larger concentrated sources such as EGUs and Non-EGU point sources.

Figure V-4: Sector Contributions to the Arkansas 2017 SO_2 Emissions Inventory



3. Key Emissions Sectors

Chapters II and III describe the projected relative contribution of different emission source sectors to visibility impairment on the most impaired days in 2028 at the federal Class I areas in Arkansas (Chapter II) and in federal Class I areas that may be affected by emissions from Arkansas (Chapter III). Table V-2 summarizes the sectors with the largest impact on each of the identified federal Class I areas according to EPA modeling.

Table V-2: Summary of Key Sectors Affecting Visibility Impairment in 2028

Class I area	**Key Sectors Affecting Visibility Conditions in 2028**
Caney Creek	EGUs (45%), Non-EGU Point (23%)
Upper Buffalo	EGUs (45%), Non-EGU Point (19%)
Mingo	EGUs (42%), Non-EGU Point (19%)
Hercules Glades	EGUs (42%), Non-EGU Point (18%)
Mammoth Cave	EGUs (46%), Non-EGU Point (21%)
Sipsey	EGUs (42%), Non-EGU Point (21%)
Wichita Mountains	EGUs (27%), Non-EGU-Point (20%), Oil & Gas (19%)
Shining Rock	EGUs (43%), Non-EGU Point (29%)

The projected 2028 source apportionment data suggests that the key sectors impacting visibility in the federal Class I areas in Arkansas and in those areas that may be affected by emissions in Arkansas are EGUs, Non-EGU Point, and Oil & Gas. EGUs and Non-EGU point sources are permitted by DEQ as stationary sources. The larger sources within the Oil & Gas sector (major pipeline and compressor stations) in Arkansas are also permitted as stationary sources.

4. Key Pollutants and Source Categories Summary

DEQ finds that it is reasonable to focus its reasonable progress evaluation for Planning Period II on stationary sources of NOx and SO_2. Recent monitor data show that the dominant anthropogenic pollutant(s) impacting visibility conditions on the most impaired days at the federal Class I areas in Arkansas and those in other states that may be affected by emissions from Arkansas is ammonium nitrate, ammonium sulfate, or both. The precursors of ammonium nitrate and ammonium sulfate include ammonia, NOx, and SO_2. In Arkansas, 98% of ammonia emissions come from sources outside the scope of DEQ’s regulatory. Thirty-five percent of NOx emissions and eighty-nine percent of SO_2 emissions come from stationary sources that are regulated by DEQ. The source apportionment data show that point sources (stationary sources) are projected to continue to contribute the most to visibility impairment at these federal Class I areas. Based on this data, DEQ sees no reasonable basis for seeking additional regulatory authority to address other source categories at this time.

B. Selection of Stationary Sources of NOx and SO_2 for Analysis

DEQ used the 2016 results from the Ramboll AOI study performed for the CenSARA states to select stationary sources for consideration.[5] DEQ used a threshold of seventy percent of cumulative percentage of 2016 AOI Impacts for NOx and SO_2 combined to determine which sources to bring forward for a source-specific analysis. This screening method brings forward for further analysis five facilities in Arkansas. Table V-3 lists each facility, the federal Class I areas that each facility impacts, major emission units, and existing controls at the facility.

Consistent with EPA Guidance, this analysis was designed to ensure that source selection resulted in a set of pollutants and sources the evaluation of which has the potential to meaningfully reduce their contributions to visibility impairment.[6] DEQ also considered a threshold of 80% during the early stages of methodology development. This brought forward another eighteen sources, but all with minimal visibility impact relative to other sources on Class I Areas. The seventy percent threshold occurred at a natural break in data distribution, included the highest contributors to visibility impairment at Class I Areas, and did not unnecessarily bring forward minimal-impact sources for four-factor analysis. Consistent with EPA's July 8, 2021 Memo, *Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period* (page 4), the additional sources that would have been brought forward for analysis would not have had the "potential to meaningfully reduce contributions to visibility impairment."

Table V-3: Arkansas Sources Selected for Further Analysis

Facilities	Areas Impacted	Major Emissions Unit(s)	Existing SO_2 Controls	Existing NOx Controls
White Bluff Power Plant	Caney Creek Upper Buffalo Hercules Glades	2 Coal-fired electric generating units	Low Sulfur Coal	Low NOx Burners with Separated Overfire Air
Independence Power Plant	Upper Buffalo Hercules Glades Mingo	2 Coal-fired electric generating units	Low Sulfur Coal	Low NOx Burners with Separated Overfire Air

[5] AR Screening Method – V3.2_2016 Inventory Data Sheet included in Appendix C.

[6] EPA's July 8, 2021 Memo, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (page 4)

	Caney Creek			
FutureFuel Chemical Co.	Upper Buffalo Hercules Glades	3 Coal-fired boilers	None	None
Domtar A.W. LLC – Ashdown Mill	Caney Creek Wichita Mountains	Power Boiler 2	Venturi scrubbers	Overfire air
		Power Boiler 3	None	Overfire air
		Recovery Boiler 2	None	None
		Recovery Boiler 3	None	None
Flint Creek Power Plant	Upper Buffalo Hercules Glades	1 Coal-fired electric generating unit	Novel Integrated Desulfurization (Dry Lime FGD)	Low NOx Burners with Overfire Air

This method also brings forward 18 sources in other states. These sources are listed in Table V-4. DEQ sent a letter to each of these states asking the states to consider performing a four-factor analysis on the selected sources. These "Ask" letters are included in Appendix D of this SIP submittal.

Table V-4: Sources in other states selected for inclusion in "Ask" letters

State	Facility	Areas Impacted
Texas	Martin Lake Electrical Station	Caney Creek, Upper Buffalo
	AEP Pirkey	Caney Creek, Upper Buffalo
	Welsh Power Plant	Caney Creek, Upper Buffalo
	WA Parish Electric Generating Station	Caney Creek
Louisiana	CLECO Power LLC Dolet Hills	Caney Creek, Upper Buffalo
	Entergy Louisiana LLC- Roy S Nelson Plant	Caney Creek
Oklahoma	Muskogee Generating Station	Caney Creek, Upper Buffalo
	Hugo Generating Station	Caney Creek, Upper Buffalo
	Grand River Energy Center	Upper Buffalo
Missouri	Ameren Missouri Labadie Plant	Upper Buffalo
	Ameren Missouri Rush Island Plant	Upper Buffalo
	New Madrid Power Plant Marston	Upper Buffalo
	City Utilities of Springfield Missouri John	Upper Buffalo

	Twitty Energy Center	
	Thomas Hill Energy Center Power Division	Upper Buffalo
Illinois	Prairie Generating Station	Upper Buffalo
Indiana	Indiana Michigan Power DBA AEP Rockport	Upper Buffalo
	Duke Energy Indiana LLC - Gibson Genera	Upper Buffalo
Kentucky	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	Upper Buffalo

DEQ shared these lists of sources with EPA and the FLMs. In response, EPA asked DEQ to consider whether the retirement or installation of controls at certain sources in Texas and Oklahoma that occurred after 2016, the emissions year in the AOI analysis inventory, might impact source-selection.[7] Specifically, EPA suggested revising the emissions for the following sources while maintaining the 2016 emissions for the remainder of the inventory:

- Remove or zero-out the emissions of Sandow, Big Brown, and Monticello in Texas, which shut down in 2018; and
- Use 2019 emissions for Sooner and Muskogee in Oklahoma, which implemented control strategies that reduced their SO_2 emissions in 2018.

DEQ disagrees with selectively updating emissions for some sources, but not others. Either the analysis should be based on the emissions of all sources in the year analyzed or emissions from all sources should be updated. At the time the AOI study was prepared for CenSARA, 2016 was the most recent year of emissions data for all sources. Updating the emissions for all sources for would be an unreasonable diversion of DEQ and/or CenSARA resources as well infeasible to complete as a practical matter given the deadline for submittal of the second planning period SIP. The 2016 AOI results provide an adequate representation of the relative contribution of stationary sources to visibility impairment at the federal Class I areas at the start of the second planning period for the purposes of screening sources for further analysis. DEQ chose not to use the projected 2028 AOI data because it reflects some of changes based on unrealistic assumptions from the Integrated Planning Model for 2028 emissions from EGUs.

Nevertheless, DEQ has performed a sensitivity analysis to see if EPA's requested change would alter the Arkansas sources brought forward for further analysis for Planning Period II. DEQ performed this sensitivity analysis for each of the federal Class I areas that includes at least one Arkansas source in the 2016 AOI and at least one of the five sources identified by EPA.[8] The spreadsheet used for this analysis is included in Appendix E. At a seventy percent selection

[7] See email from Michael Feldman (EPA R6) dated April 13, 2020 included in Appendix D.

[8] Caney Creek, AR; Upper Buffalo, AR; Hercules Glades, MO; and Wichita Mountains, OK are the only federal Class I areas for which the data that include at least one of the five sources mentioned by EPA in the 0.05% EWRT threshold AOIs. Therefore, there would be no changes for Isle Royale, Badlands, Sipsey, Mammoth Cave, or Mingo.

threshold, this sensitivity analysis would bring in two additional sources in Arkansas for further consideration. These two sources are included in Table V-5.

Table V-5: Additional Potential Sources based on Sensitivity Analysis

Facilities	2016 NOx Emissions (tons)	2016 SO_2 emissions (tons)	Major Emissions Unit(s)
Weyerhaeuser NR Company – Dierks Mill	201.441	23.236	SN 45 Wood-fired Boilers
Albemarle Corporation – South Plant	113.42	1650.361	SR-01 Tail Gas Incinerator

Weyerhaeuser NR Company – Dierks Mill (Dierks Mill) is a sawmill that processes lumber and wood residuals. This plant has relatively low emissions of NOx and SO_2 compared to the sources selected with the seventy percent threshold based on the 2016 AOI (with no emissions substitutions). The mill is located 40 km from Caney Creek. Dierks Mill has one major emission unit for NOx (100 tpy or greater) and none for SO_2. This emission unit is a 249.0 MMBtu/hr wood-fired boiler that combusts wood, small amounts of waste paper generated on site, and small quantities of sawdust.[9] This boiler was last operated in 2017 and removed from the Dierks Mill permit in May 2020.[10] Based on the Dierks Mill's wood-fired boiler's maximum fuel consumption rating and low annual emissions as compared to larger sources of NOx emissions, DEQ does not anticipate that retrofit post-combustion controls would have been reasonable even if this unit had continued to operate. Based on this assessment, addition of Dierk's Mill to the set of sources for evaluation using the four factors would not produce more potential for meaningfully reducing contributions from Arkansas sources to visibility impairment at Class I areas.

Albemarle Corporation – South Plant (Albemarle South) is a chemical manufacturer that extracts bromine-containing brine from geologic formations. The facility has one major emission unit for SO_2 (100 tpy or greater) and none for NOx. This emission unit is itself part of a control system that burns off tail gas from the sulfur recovery plant. The sulfur recovery plant removes ninety-three percent of the sulfur from sour gas created during bromine separation from the extracted brine. Based on a review of the RACT/BACT/LAER database, DEQ did not identify any additional technically feasible SO_2 controls for this type of emission unit that could be implemented in addition to the existing control (tail gas incinerator). Based on this assessment, addition of Albermarle South to the set of sources for evaluation using the four factors would not

[9] EPA's Control Cost Manual provides retrofit cost estimation information based on studies of boilers with 250 MMBtu/hr or greater.

[10] Permit No. 0023-AOP-R14

produce more potential for meaningfully reducing contributions from Arkansas sources to visibility impairment at Class I areas.

EPA's suggested source selection adjustments would make no difference in the sources that DEQ would analyze using the four reasonable progress factors. Furthermore, the changes at Dierks Mill highlight the rationale for not selectively updating only the handful of sources that EPA R6 requested. Any changes to facilities occurring after the historical year used for screening (2016) will be reflected in the 2028 reasonable progress goals.

Consistent with EPA guidance, DEQ selected sources to perform additional analyses to determine what control measures are necessary to achieve reasonable progress. The four sources that DEQ selected for further analysis were Independence Power Plant, Future Fuel Chemical Company, Domtar Ashdown Mill, and Flint Creek Power Plant. DEQ then determined which potential emission control measures to consider for each facility and, based on information from the four-factor analysis for each facility, determined what emission control measures will be necessary to make reasonable progress for the second implementation period.

C. Analyses for Selected Sources

DEQ gathered data for each selected source to evaluate for potential emission control measures through a combination of permit review, information collection requests (ICRs)[11], and emission inventory data. For each selected source, DEQ identified the emission units that emit the majority of SO_2, NOx, or both; identified existing controls in place at each of the identified emission units, and identified potential control strategies that may be technically feasible for each emission unit. These data, together with historic and projected visibility data at Class I areas in Arkansas and in other states that may be affected by emissions from Arkansas, were evaluated to assess what emission control measures, if any, at the selected sources are necessary to achieve reasonable progress during Planning Period II.

1. Characterization of Factors for Emission Control Measures

Clean Air Act 169A(g) and the RHR at 40 C.F.R. 51.308(f)(2)(i) requires states consider four factors in its evaluation to determine whether emission reduction measures for selected sources are necessary to make reasonable progress: cost of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment. However, a state is not limited to solely considering these factors. In addition to the mandatory factors, DEQ also considered in its evaluation the progress that has been achieved at these federal Class I areas, the anticipated visibility impairment in 2028 at these federal Class I areas. This approach is consistent with the flexibility provided to states under the RHR, the

[11] Information collection requests and responses are included in Appendices F–I.

recommendations included in EPA's guidance, and the iterative nature of the regional haze program.

a. Cost of Compliance

For the purposes of DEQ's evaluation, the cost of compliance is expressed in terms of cost per ton of emissions reduced by a potential control strategy. To determine the numerator in the cost/ton metric, DEQ's ICR instructed the permittees to quantify the annual cost of implementing each technically feasible potential control strategy using the EPA Pollution Control Cost Manual[12] overnight methodology. DEQ reviewed the cost information provided to ensure that the estimated costs were reasonable and consistent with the EPA Pollution Control Cost Manual. To determine the denominator in the cost/ton metric, DEQ's ICR instructed the permittees to quantify their baseline actual emission rate,[13] the control rate, and the resulting annual emission reductions that would be anticipated from each potential control technology.

This cost/ton metric for expressing cost of compliance is consistent with EPA guidance[14] and allows DEQ to perform an "apples-to-apples" comparison of the cost of different control options at the same source and across different sources. This metric also allows for comparison against the cost of measures that have been previously implemented as part of Regional Haze Planning Period I plans or in response to other Clean Air Act requirements.

EPA guidance also states that "when the cost/ton of a possible measure is within the range of the cost/ton values that have been incurred multiple times by sources of similar type to meet regional haze requirements or any other [Clean Air Act] requirement, this weighs in favor of concluding that the cost of compliance is not an obstacle to the measure being considered necessary to make reasonable progress."[15] Based on this guidance, DEQ performed a survey of cost/ton values that were incurred as a result of BART and reasonable progress determinations during Planning Period I. DEQ escalated the cost/ton values of each determination to 2019 dollars using the Chemical Engineering Plant Cost Index. DEQ did not include any BART-alternatives in this analysis because many BART alternatives were either trading programs or selected on the basis that an operations change suggested by a facility had greater visibility benefit than what would be achieved by BART rather than on a technology-specific cost-basis. The spreadsheet of compiled Planning Period I costs/ton is included in Appendix J. Table V-6 provides summary statistics for Planning Period I cost/ton by emission unit type. These summary statistics provide options for selection of a threshold for DEQ to use to determine potential control measures for

[12] https://www.epa.gov/economic-andcost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[13] Generally, the baseline period for this analysis was January 1, 2017 – December 31, 2019. However, DEQ requested shorter baseline periods for certain emission units based on controls implemented after January 1, 2017.
[14] EPA's 2019 "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period
[15] EPA's 2019 "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period

which cost is not an obstacle to the measure being considered necessary to make reasonable progress.

Table V-6: Descriptive Statistics for Cost/Ton Values of Planning Period I Source-Specific Control Technology Determinations by Emission Unit Type

Emission Unit Type	MIN	MAX	MEAN	MEDIAN	STDEV	98th Percentile
EGU Boiler	(57)	5,193	2,023	1,419	131	**5086**
Industrial Boiler	428	3,732	1,406	833	428	**3328**
Kiln	514	4,774	1,567	1,143	514	**4194**
Smelter	912	1,044	978	93	912	**1041**
All	*(57)*	*5,193*	*1,905*	*1,353*	*(57)*	*4989*

DEQ has selected a 98th percentile for each emission unit type listed in Table V-6 as a threshold to evaluate the cost of compliance for each potential control strategy evaluated for the selected sources for Planning Period II. This metric ensures that costs incurred multiple times by sources of a similar type are captured while potential outliers that may have only occurred once or twice are eliminated.

DEQ's decision to select different thresholds for different emission unit types is reasonable because certain aspects of the four factors have different implications for different facilities. One such distinction is how the costs of compliance are financed and on whom those costs are imposed. For example, the cost of compliance for investor-owned EGUs in Arkansas, such as Flint Creek, is passed on to ratepayers by statute that allows the recovery of investments to comply with administrative rules or that related to the protection of the public health, safety, or the environment. By contrast, the costs of Industrial Boilers are borne by the company that owns that facility. Whether these costs can be absorbed by the facility owners or passed on to customers is a matter of the market for the goods or services the facility provides.

Although DEQ has created a cost-effectiveness threshold, there may be circumstances for which multiple control strategies are cost-effective. Cost-effectiveness is just one of the four factors states must consider and there may be other factors beyond the four statutory factors that inform a state's decision-making. For example, in Planning Period I, DEQ identified three cost-effective control strategies for the Entergy Independence coal-fired boilers: fuel switching to LSC, Dry FGD, and Wet FGD.[16] Wet FGD was eliminated based on an EPA analysis that found that the high incremental cost between Dry FGD and Wet FGD was not justified given the minimal incremental increase in visibility benefit that would be achieved over Dry FGD. Although Dry FGD is a more stringent control, DEQ selected LSC as the control for the Independence units necessary to make reasonable progress during Planning Period I because the cost-effectiveness

[16] 2018 Planning Period I, Phase II Arkansas SIP, https://www.adeq.state.ar.us/air/planning/sip/pdfs/regional-haze/rh-phase-ii-sip-narrative-final.pdf

value was better, overall costs were lower than Dry FGD resulting in less of a burden to electricity ratepayers, and Arkansas Class I areas were already making substantial progress toward natural visibility conditions. This decision was approved by EPA in its 2019 action on the Phase II SIP revision for Planning Period I.[17]

b. Time Necessary for Compliance

The time necessary for compliance factor requires estimation of the time needed for the source to come into compliance with a potential control measure in an "efficient manner without unusual amounts of overtime, above-market wages and prices, or premium charges for expedited delivery of control equipment."[18] Although a required factor for consideration, time necessary for compliance is more relevant to establishing compliance schedules for control measures determined to be necessary to ensure reasonable progress rather than for determining whether a potential control measure is reasonable and necessary. The time necessary for compliance can play a role in determining the cost of compliance if the remaining useful life for an emission unit is less than the life of the equipment involved in the potential control measure(s) under consideration. Specifically, the time necessary for compliance may influence how capital costs of control measures are annualized under such circumstances.

c. Energy and Non-Air Environmental Quality Impacts of Compliance

Unless the non-air environmental quality impact of compliance for a potential control measure renders that control measure technically infeasible, DEQ's ICR instructed the permittees of selected sources to specify any energy and non-air environmental impacts and factor the associated costs into the cost of implementing a potential control measure. Therefore, this factor is subsumed into the cost of compliance factor for the purposes of DEQ's evaluation.

d. Remaining Useful Life

For the purposes of DEQ's evaluation, the remaining useful life factors into the cost of compliance. If an emission unit has an enforceable requirement to cease operation, this may shorten the number of years over which capital costs are annualized and thus increase the cost/ton amount. If there is no such enforceable requirement, annualization of capital costs is based on the expected life of the equipment involved in the potential control measures under evaluation. EPA guidance also explicitly provides that states may choose not to conduct a four-

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[17] Approval and Promulgation of Implementation Plans; Arkansas; Approval of Regional Haze State Implementation Plan Revision for Electric Generating Units in Arkansas, 84 FR 51033-01

[18] EPA's 2019 "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period". Page 45
https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period

factor analysis for a particular source if that source is "expected to close by December 31, 2028, under an enforceable requirement."[19]

e. Visibility Considerations

Consideration of historical and projected visibility progress provides valuable context for the consideration of potential control measures that may be necessary for ensuring reasonable progress. As described in Chapters II and III, federal Class I areas in Arkansas and federal Class I areas in other states that may be affected by emissions from Arkansas made considerable progress towards natural visibility conditions on the most impaired days during Planning Period I. Projected 2028 conditions for each Class I area, with the exception of Wichita Mountains, are on track with any glidepath the relevant state may choose to establish in their Planning Period II SIP before consideration of additional control measures to ensure reasonable progress. Any additional controls required by DEQ and/or other states will further accelerate progress toward natural visibility conditions during Planning Period II.

2. Evaluation of Potential Control Measures for White Bluff Power Plant

White Bluff Power Plant (White Bluff) is a coal-fired electric generating station located in Jefferson County, Arkansas. White Bluff has two major emissions units: Unit 1 and Unit 2. Unit 1 and Unit 2 are identical tangentially-fired 850 megawatt boilers with a maximum heat input capacity of 8,950 MMBtu/hr each. Units 1 and 2 burn sub-bituminous coal as a primary fuel. Units 1 and 2 are equipped with low NOx burners with separated overfire air to control NOx emissions and electrostatic precipitators to control particulate matter emissions.

Entergy is required to comply with an emissions limit of 0.60 lb SO_2/MMBtu for Units 1 and 2 on a thirty-boiler-operating-day rolling average based on fuel switching to lower sulfur coal by August 7, 2021 pursuant to an agreed order between DEQ and Entergy as part of the 2018 Phase II Regional Haze SIP revision.[20] This state- and federally-enforceable administrative order also requires Units 1 and Units 2 to cease coal-fired operations by no later than December 31, 2028.

DEQ considers the enforceable requirement to cease coal-fired operations at White Bluff by December 31, 2028 to be sufficient reason to not perform a four-factor analysis for this source for Planning Period II. This determination is consistent with EPA guidance on source selection for four-factor analyses.[21] It is clear that no additional control measures will be cost-effective for this source. As demonstrated in DEQ's Phase II SIP revision for Planning Period I, additional

[19] Ibid., Page 20.

[20] Administrative Order LIS No. 18-073, dated August 7, 2018; accessible here: https://www.adeq.state.ar.us/air/planning/sip/pdfs/regional-haze/entergy-ao-executed-8-7-2018.pdf

[21] Page 20 of EPA's 2019 "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" instructs states that "If a source is expected to close by December 31, 2028, under an enforceable requirement, a state may consider that to be sufficient reason to not select the source at the source selection step."

control measures beyond the low NOx burners and low sulfur coal, which have already been implemented at White Bluff, were not cost-effective due to the plant's remaining useful life.[22] The annual cost for control measures evaluated during Planning Period I would only be expected to increase in an updated reasonable progress analysis because White Bluff is nearer to its cessation of coal-fired operations date than it was in the previous analysis. The technologies available to reduce NOx and SO_2 at power plants, such as White Bluff, have not changed since 2018.[23] This determination is also consistent with EPA guidance that allows for the exclusion of sources from additional analyses when it is clear that no additional control measures will be adopted.[24]

DEQ has determined that existing control measures at White Bluff are sufficient for reasonable progress. The requirement to burn low sulfur coal is already part of the SIP. The low NOx burners installed at White Bluff are an inherent part of equipment design (i.e., cannot be shut down temporarily, as is the case with a post-combustion control). Therefore, no separate emission limit is necessary for inclusion in the SIP to ensure operation of the low NOx burners.

If Entergy chooses to continue operations of the White Bluff units after December 31, 2028, they must apply for a permit revision to burn a different fuel. Such a permit revision would be subject to new source review requirements. If the change would result in a significant increase in emissions, prevention of significant deterioration and best available control technology requirements would be triggered. The most likely fuel switch would be to natural gas, which inherently emits much less SO_2 and NOx relative to coal.[25, 26]

[22] See EPA's Final Rule, 84 FR 51033, at page 51040: "Under a BART analysis, the remaining useful life of a scrubber is assumed to be 30 years unless a facility has an enforceable agreement in place to shut down or cease coal combustion earlier [ ] Entergy entered into an Administrative Order with ADEQ [ ] to cease coal combustion at Units 1 and 2 at White Bluff by December 31, 2028. It was therefore appropriate for ADEQ to rely on this cease to combust coal date for White Bluff Units 1 and 2 in the calculation of the units' remaining useful life, which is used to determine the cost effectiveness of controls in the BART analysis."

[23] See EPA's Menu of Control Measures. https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation

[24] EPA's 2019 "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" at Page 20 states: "EPA expects that, typically, states are more likely to select sources based on visibility impacts and not consider the four reasonable progress factors (i.e., cost of compliance, remaining useful life, time necessary for compliance, and energy and non-air quality environmental impacts) until after a source is selected. However, in some cases, a state may already have information on one or more of the four reasonable progress factors at the time of source selection. If so, the state may consider that information at the source-selection stage. In particular circumstances, that information may indicate that it is reasonable to exclude the source for evaluation of emission control measures because it is clear at this step that no additional control measures would be adopted for the source."

[25] EPA's Menu of Control Measures estimates that fuel switching from subbituminous coal to natural gas has a typical control efficiency of 99.9%. https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation

[26] EPA (2014). Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating

3. Independence Power Plant

The Entergy Independence Power Plant (Independence) is a coal-fired electric generating station located in Independence County, Arkansas. Independence has two identical 900 megawatt boilers: Unit 1 and Unit 2. These boilers burn Wyoming Powder River Basin sub-bituminous coal as their primary fuel and No. 2 fuel oil or bio-diesel as start-up fuel. Independence was identified by DEQ, Oklahoma Department of Environmental Quality, Missouri Department of Natural Resources, and the VISTAS as a source whose NOx and/or SO_2 emissions may affect visibility conditions in federal Class I areas.

The two Independence units are equipped with low-NOx burners with separated overfire air to control NOx emissions and electrostatic precipitators to control particulate matter emissions. Entergy is required to comply with an emission limit of 0.60 lb SO_2/MMBTU for these two units on a thirty-boiler-operating-day rolling average based on fuel switching to lower sulfur coal by August 7, 2021, pursuant to an agreed order between DEQ and Entergy as part of the 2018 Phase II Regional Haze SIP revision.[27]

On January 8, 2020, DEQ sent an ICR to Entergy asking for information about potential emission reduction strategies for SO_2 and NOx emissions from Independence Units 1 and 2. Specifically, DEQ requested updated information regarding the following control technologies:

- SO_2 (ranked from highest control efficiency to lowest)[28]
    - Fuel Switching from coal to natural gas
    - Wet Gas Scrubber (Wet FGD)
    - Spray Dryer Absorber (Dry FGD)
    - In-Duct Dry Sorbent Injection (DSI)
- NOx (ranked from highest control efficiency to lowest) for all units[29]
    - Selective Catalytic Reduction (SCR)
    - Selective Non-Catalytic Reduction (SNCR)

On April 7, 2020, Entergy provided information responsive to DEQ's ICR. This response is included in Appendix F. DEQ's evaluation of potential control strategies for Independence is based on the information contained in Entergy's response.

a. Technical Feasibility of Identified Control Strategies

Units—GHG Abatement Measures. Office of Air and Radiation.

[27] The emission limits for Entergy Independence Unit 1 and Unit 2 are 8,091.0 lbs/hr for SO_2 and 6,090.0 lbs/hr for NOx. The SO_2 limit is contained in the Arkansas SIP, and the NOx limit, based on the use of low-NOx burners, is contained in a federally-enforceable Title V permit.

[28] EPA Menu of Control Measures https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation

[29] EPA Menu of Control Measures https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation

Wet FGD, Dry FGD, DSI, SCR, and SNCR are technically feasible control technologies for Independence Units 1 and 2, and fuel switching to natural gas is not a feasible control technology for the purpose of DEQ's reasonable progress analysis. In their response to the ICR, Entergy explains that fuel-switching from coal to natural gas would not be a feasible control strategy for Independence. In particular, Entergy points out that fuel-switching the two 880 MW units would be a "significant and fundamental change," and that the modifications necessary to make such a switch have not been demonstrated in similarly sized units. EPA's 2019 "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" states that "[s]tates may also determine that it is unreasonable to consider some fuel-use changes because they would be too fundamental to the operation and design of a source.[30] In addition, Entergy stated that the installation of a natural gas pipeline to connect to the nearest existing pipeline five miles away could result in negative impacts to streams and wetlands along the pipeline route. Furthermore, a switch to natural gas at Independence would render the plant less efficient relative to units originally designed to burn natural gas. Based on the information provided by Entergy and EPA guidance, DEQ finds that it is unnecessary to perform an analysis of the fuel-switching from coal to natural gas as an emission reduction strategy for the Independence units.

b. Baseline Emission Rate

Entergy provided baseline SO_2 and NOx emissions for each Independence unit annualized on both a maximum monthly emission rate basis and an average monthly emission rate basis for the period of November 1, 2018, to December 31, 2019, for Unit 1 and January 1, 2018, to December 31, 2019, for Unit 2.[31] DEQ used the maximum monthly emission rate to ensure that control technology evaluated is adequately sized for the purposes of control cost calculations. DEQ used the average monthly baseline emission rate to estimate typical emission reductions that can be anticipated from the application of a control strategy. Table V-7 summarizes baseline emissions on an average monthly basis for Independence.

Table V-7: Entergy Independence Baseline Emissions (Average Month Basis)

Emission Unit	SO_2 Baseline Emissions (tpy)	NOx Baseline Emissions (tpy)
Unit 1	9,945	3,423
Unit 2	10,672	3,180

c. Control Effectiveness

Table V-8 summarizes the control effectiveness of each technically feasible emission reduction strategy evaluated for the Independence units in Entergy's response to DEQ's ICR.

[30] EPA (2019). "Guidance on Regional haze State Implementation Plans for the Second Planning Period," p.30.

[31] DEQ requested this baseline period for Independence based on the timing of installation of low-NOx burners for Independence Units 1 and 2.

Table V-8: Control Effectiveness and Emission Reductions Estimated for Control Strategies Evaluated for Entergy Independence

Emission Unit	Control Strategy	Pollutant	Controlled Emission Rate (lb/MMBtu)	Estimated Emission Reductions (tpy)
Unit 1	WFGD	SO_2	0.04	9,104
	DFGD	SO_2	0.06	8,864
	Enhanced DSI	SO_2	0.15	6,792
	DSI	SO_2	0.35	2,587
	SCR	NOx	0.055	2,267
	SNCR	NOx	0.13	690
Unit 2	WFGD	SO_2	0.04	9,786
	DFGD	SO_2	0.06	9,342
	Enhanced DSI	SO_2	0.15	7,347
	DSI	SO_2	0.35	2,914
	SCR	NOx	0.055	1,961
	SNCR	NOx	0.13	298

d. Cost of Compliance

In their response to DEQ's ICR, Entergy calculated the cost of the compliance based on the assumption that the Independence units will cease coal-fired operations by December 31, 2030. In addition, Entergy used a seven percent interest rate for annualizing capital costs. This interest rate is consistent with past cost analyses for regional haze planning and the interest rate for calculating the social cost of rulemaking referenced in the EPA Control Cost Manual. However, EPA Region 6 has indicated a preference for evaluating costs annualized based on the bank prime rate consistent with EPA Control Cost Manual guidance on private investments.[32] In addition, the EPA Cost Control Manual is focused on "private cost" rather than "social costs." EPA does not present the methodologies for social cost calculations in the EPA Cost Control Manual.[33]

The EPA Control Cost Manual recommends that assessments of private cost "should be prepared using firm-specific nominal interest rates if possible, or the bank prime rate if firm-specific interest rates cannot be estimated or verified."[34] Therefore, DEQ has calculated the annualized capital costs using the total capital investment estimates provided by Entergy and a 3.25% interest rate (bank prime rate on July 16, 2020). For comparison, DEQ has also calculated annual costs based on the expected life of the control equipment evaluated in the event that these units

[32] Email from Dayana Medina, EPA Region 6 dated July 16, 2020, which is included in Appendix D.

[33] EPA (2002). Chapter 2 - Cost Estimation: Concepts and Methodology. in "EPA Air Pollution Control Cost Manual (Sixth Edition)." Page 5 ("we will not present the methodologies for social cost calculations.")

[34] *Id.* at pages 2-15

were to continue to operate with no assumed operation cessation date.[35] DEQ's cost calculations are included in Appendix F.

Table V-9 presents the estimated costs for the control strategies evaluated for the Independence units using a 3.25% interest rate for both Entergy's remaining useful life (RUL) assumptions and equipment life assumptions in 2019 dollars.[36] Table V-10 provides the cost-effectiveness of each of these strategies on an average month basis for each unit. Table V-10 also presents the cost-effectiveness averaged across both units. Because both units are identical in design and perform the same function at the same plant, implementing a control on only one unit could result in reducing the use of that unit and increasing the use of the other. As a result, the emission reductions estimated from controlling the one unit would likely not be fully achieved.

Table V-9: Estimated Total Annual Cost of Evaluated Control Strategies for Independence in 2019 Dollars

Emission Unit	Control Strategy	Total Annual Cost ($2019 MM/year)	
		Entergy RUL Assumptions	Equipment Life Assumptions
Unit 1	WFGD	163.78	58.14
	DFGD	128.76	29.47
	Enhanced DSI	98.40	47.18
	DSI	52.72	26.01
	SCR	62.31	13.33
	SNCR	9.34	7.18
Unit 2	WFGD	163.78	58.14
	DFGD	128.76	29.47
	Enhanced DSI	98.40	47.18
	DSI	52.72	26.01
	SCR	62.31	13.33
	SNCR	9.34	7.18

[35] Equipment life assumptions: Thirty years for WFGD, FGD, Enhanced DSI, DSI, and SCR and 20 years for SNCR.
[36] Chemical Engineering Plant Cost Index used to escalate costs provided by Entergy to 2019.

Table V-10: Estimated Cost-Effectiveness of Evaluated Control Strategies for Independence in 2019 Dollars

Emission Unit	Control Strategy	Pollutant	Cost-effectiveness ($2019/ton)	
			Entergy RUL Assumptions	Equipment Life Assumptions
Unit 1	Wet FGD	SO_2	17,953	6,349
	Dry FGD	SO_2	14,791	3,357
	Enhanced DSI	SO_2	14,449	6,905
	DSI	SO_2	20,325	9,996
	SCR	NOx	27,419	5,812
	SNCR	NOx	13,529	10,401
Unit 2	Wet FGD	SO_2	16,701	5,907
	Dry FGD	SO_2	13,749	3,121
	Enhanced DSI	SO_2	13,357	6,383
	DSI	SO_2	18,044	8,875
	SCR	NOx	31,698	6,719
	SNCR	NOx	31,325	24,084
Average of Units 1 and 2	Wet FGD	SO_2	17,363	6,164
	Dry FGD	SO_2	14,305	3,274
	Enhanced DSI	SO_2	13,940	6,684
	DSI	SO_2	19,234	9,489
	SCR	NOx	29,632	6,340
	SNCR	NOx	22,445	17,259

Table V-10 illustrates that cost-effectiveness based on the assumption of a 2030 cessation of coal-fired operation of Unit 1 and Unit 2 greatly increases the annual cost of compliance above the annual costs that would be incurred over the life of the control equipment. The cost of all potential control strategies examined exceeds DEQ’s cost threshold for EGU boilers under the assumption that coal-fired operations of Independence Units 1 and 2 ceases by December 31, 2030. Based on equipment life, only Dry FGD would fall below the threshold.

e. Time Necessary for Compliance

Table V-11 provides a summary of the time that Entergy indicated would be necessary to comply with each of the assessed control technologies.

Table V-11: Time Necessary to Comply for Evaluated Control Strategies for Independence

Control Strategy	Time Necessary to Comply	Basis
Wet FGD	5 years	Time determined necessary for compliance in EPA 2016 FIP
Dry FGD	5 years	Time determined necessary for compliance in EPA 2016 FIP
Enhanced DSI	3 years	None provided by Entergy in 2020 Response
DSI	3 years	None provided by Entergy in 2020 Response
SCR	5 years	Precedent in Utah and North Dakota FIPs[37]
SNCR	5 years	Precedent in Utah and North Dakota FIPs

DEQ finds it is reasonable to rely on the estimates provided in Table V-11 for this specific source. Entergy did not provide a basis for the time necessary to implement enhanced DSI and DSI in their April 7, 2020 response to DEQ's ICR. However, similar estimates of time necessary to comply have been provided for these technologies in other analyses.[38] As a result, it is appropriate to rely on the time necessary for compliance information provided for these two control technologies as well.

f. Energy and Non-Air Quality Impacts

Entergy reported that each SO_2 control technology evaluated (Wet FGD, Dry FGD, and DSI) would result in generation of additional wastes. Wet FGD and Dry FGD would increase water consumption. In addition, Entergy would no longer be able to sell fly ash if DSI were implemented due to sodium byproducts in the ash produced during reaction of the sorbent (Trona) and SO_2.

Entergy reported that both NOx control technology evaluated (SCR and SNCR) would increase electricity needs to operate the system. In addition, the storage of aqueous ammonia that would be used by either system presents a risk to health of persons in the vicinity in the event of an accidental release. Operation of SCR and SNCR may also release unreacted ammonia into the atmosphere if temperatures during ammonia injection are too low or if there is an over-injection of ammonia. In addition, disposal of spent SCR, if it cannot be recycled, must be disposed of as a waste.

The energy and non-air quality impacts associated with the reviewed technology have been factored into the cost of compliance.

[37] 77 FR 20944 (April 6, 2012) and 81 FR 43907 (July 5, 2016), respectively.
[38] See FutureFuel Chemical Company's response to DEQ's ICR in Appendix G.

g. Remaining Useful Life of the Source

Entergy used an assumption of 5.42 years remaining useful life for both Enhanced DSI and DSI to annualize capital and indirect costs. Entergy used 3.42 years for all other assessed technologies. These remaining useful life assumptions are based on the time necessary for compliance and Entergy's plans to cease coal-fired operations at both Independence units by December 31, 2030.

On March 11, 2021, Entergy entered into a consent decree with Sierra Club that renders Entergy's planned cessation of coal-fired operations at Independence by December 31, 2030 binding.[39] In addition, DEQ proposes to enter into an administrative order with Entergy that would render the requirement to cease coal-fired operations by no later than December 31, 2030 at Independence enforceable by DEQ and, upon approval, by EPA as part of the SIP. A draft version of the proposed administrative order has been included in Appendix F for public review. Prior to submission to EPA, a final administrative order that incorporates any changes in response to public comment must be signed by DEQ and Entergy to render the requirements enforceable as a matter of state law.

h. Visibility Considerations

The 2016 results from the Ramboll AOI study indicate that emissions from Independence had a greater impact on Upper Buffalo and Hercules Glades than any other stationary source.[40] The results indicate that Independence contributed to a lesser extent to visibility impairment at Caney Creek, Mingo, and Sipsey.[41] These five Class I areas are on track to make greater progress than the URP glidepath in 2028 before consideration of potential controls for Independence. Independence is not within the nitrate or sulfate-specific area of influence for Mammoth Cave or Wichita Mountains based on the 0.05% threshold. Source apportionment from VISTAS modeling indicated that Independence was projected to contribute 1.04% of the total sulfate and 0.01% of total nitrate point source visibility impact on the most impaired days in 2028 at Shining Rock. Shining Rock is also on track to make greater progress than the URP glidepath in 2028 before consideration of potential controls for Independence.

i. Proposed Decision on Control Measures Necessary to Make Reasonable Progress

In determining whether additional control measures are necessary for Independence during Planning Period II, DEQ weighs the four statutory factors and visibility considerations. The time

[39] https://237995-729345-1-raikfcquaxqncofqfm.stackpathdns.com/wp-content/uploads/2021/03/settle.pdf

[40] The Independence visibility surrogate value was 26% of the total sum of surrogate values for all point sources in the 2016 inventory for Upper Buffalo and 20% for Hercules Glades.

[41] The Independence visibility surrogate value was 5% of the total sum of surrogate values for all point sources in the 2016 inventory for 5% for Caney Creek, 3% for Mingo, and1% for Sipsey.

necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life have been factored into the cost of compliance for the potential controls considered for Independence. The cost of compliance for each potential control strategy for Independence, given the planned cessation of coal-fired operations by December 31, 2030, exceeds DEQ's cost threshold for EGU Boilers. Similar to White Bluff, if Independence were to continue to operate past December 31, 2030, a permit revision with new source review would be required for the new fuel. Furthermore, each federal Class I area for which Independence is within the nitrate- or sulfate-specific area of influence are on track to make greater progress than the URP glidepath in 2028 before consideration of additional controls at Independence. Although the URP is not determinative in making a decision with respect to whether a control is reasonable after consideration of the four factors, being below the URP glidepath means that the additional demonstrations under 40 C.F.R. 51.308(f)(3)(ii) are not required. After consideration of the statutory factors and visibility considerations, DEQ has determined that no additional controls are necessary at Independence Units 1 and 2 to make reasonable progress during Planning Period II.

4. FutureFuel Chemical Company

FutureFuel Chemical Company manufactures specialty organic chemical intermediates used in the manufacture of color film and photographic paper, paints and coatings, plastics and bottle polymers, medical supplies, prescription medicines, food supplements, household detergents, agricultural products, and biofuel. Ninety-nine percent of the facility's SO_2 emissions and seventy-two percent of the facility's NOx emissions come from three coal-fired boilers used to produce steam and destroy chemical wastes.[42] Other emission units that emit SO_2, NOx, or both include two natural gas-fired boilers, a regenerative thermal oxidizer, thermal oxidizers and caustic scrubbers, a chemical waste destructor, a flare, two hot oil systems, a diesel glycol pump, two diesel waste disposal pumps, a diesel generator, and a diesel fire water pump.

The three coal-fired boilers are balanced draft steam generation boilers designed to operate at 70 MMBtu/hr per unit. The units share a common primary fuel conveying system, a common ash handling system, and a common 200-foot-tall stack. Each unit is equipped with its own ESP to control particulate emissions. The units do not have existing controls for NOx or SO_2.

On January 8, 2020, DEQ sent an ICR to FutureFuel asking for information about potential emission reduction strategies for SO_2 and NOx emissions from the three coal-fired boilers.

[42] 2016 ADEQ Emission Inventory

Specifically, DEQ requested information for the following potential emission reduction strategies:

- SO_2 (ranked from highest control efficiency to lowest)[43]
  - Fuel Switching from coal to natural gas
  - Wet Gas Scrubber
  - Spray Dryer Absorber (SDA)
  - DSI
  - Fuel Switching to a lower sulfur coal
- NOx (ranked from highest control efficiency to lowest) for all units[44]
  - SCR
  - SNCR
  - Low-NOx Burner

On April 7, 2020, FutureFuel provided information responsive to DEQ's ICR. This response is included in Appendix G. Additional follow-up communication to provide further technical justification and calculations are also included in Appendix G. DEQ's evaluation of potential control strategies for FutureFuel are based on the information contained in FutureFuel's response.

a. Technical Feasibility of Identified Control Strategies

SDA, Wet Scrubbing with lime slurry, fuel switching to natural gas, fuel switching to lower sulfur coal, SCR, and SNCR are technically feasible control technologies for FutureFuel's three coal-fired boilers. FutureFuel identified two options for fuel switching to natural gas: retrofitting the existing boilers and replacing the existing boilers with new boilers designed to operate using natural gas. FutureFuel identified three options for fuel switching to lower sulfur coal: 2.5% sulfur content, 2% sulfur content, and 1.5% sulfur content.

FutureFuel was unable to identify a supply of coal lower than 1.5% sulfur content that was also able to meet the heating value and fusion temperature necessary for use in the three coal-fired boilers, which are designed for coal with a heating value of at least 11,100 Btu/lb and a minimum fluid fusion temperature of 2,550 degrees Fahrenheit. Burning coal that does not meet the design requirements for FutureFuel's boilers is expected to result in caking, clinker formation, and damage to equipment. FutureFuel examined the feasibility of switching to coal from a nearby power plant (0.05% sulfur content), switching to coals from the Powder River Basin (0.8 lb SO_2/MMBTU, 8,800 Btu/lb), and switching to coals from the Uinta Basin (0.8 lb SO_2/MMBTU, 11,700 Btu/lb). Both the coal from the local power plant and Powder River Basin

[43] EPA Menu of Control Measures https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation

[44] EPA Menu of Control Measures https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation

have a heating value below the minimum heating value required for the stoker boilers and a fusion temperature value below the minimum fluid fusion temperature required for the stoker boilers. Uinta Basin coals have a sufficient heating value; however, the mean and median fusion temperatures from Uinta Basin coal are below the minimum recommended fusion temperatures for FutureFuel's stoker boilers. The distance to Uinta Basin would also require large upgrades to FutureFuel's coal trucking fleet, making the cost of fuel switching to Uinta Basin coal infeasible. Therefore, these coal types were considered technically infeasible for FutureFuel's coal-fired stoker boilers.

FutureFuel also identified wet scrubbing using sodium hydroxide as a technically infeasible emission reduction strategy because the salts that would be formed from use of this strategy could exceed National Pollution Discharge Elimination System (NPDES) sulfate permit limits. FutureFuel is subject to a sulfate limit of 70,000 lb/day based on Technology-Based Effluent Limitations (TBEL) established by DEQ. FutureFuel discharges between 15,500 and 30,000 lb sulfate/day and installation of a wet sodium hydroxide scrubber would increase discharge by 43,000 lb sulfate/day. TBEL represent the minimum level of treatment of pollutants for point sources based on available treatment technologies. Clean Water Act standards are subject to anti-backsliding requirements that prohibit the renewal, reissuance, or modification of an existing NPDES permit that contains effluent limitations, permit conditions, or standards less stringent than those established in a previous permit.[45] There are certain exceptions to the anti-backsliding requirements for TBELs:

- Material and substantial alterations or additions that justify the relaxation;
- New information that was not available at the time of permit issuance that would have justified a less stringent limitation;
- Technical mistakes or mistaken interpretation of the law;
- Events beyond the permittee's control with no reasonably available remedy;
- Modifications under Clean Water Act § 301(c), 301(g), 301(h), 310(i), 301(k), 301(n), or 316(a);
- Inability to meet effluent limits when technology upon which the TBEL was established is installed, properly operated, and maintained.[46]

Installation of a wet scrubber using sodium hydroxide to reduce sulfur dioxide emissions would likely qualify for an exception from anti-backsliding requirements for a TBEL as a "material and substantial alteration" that justifies relaxation of the effluent limitation.[47] The state water quality-based effluent limitations are 1,520,429 lb sulfate/day. Therefore, DEQ anticipates that FutureFuel could request an NPDES permit amendment from DEQ's Office of Water Quality to accommodate the additional 3,000 lb sulfate per day beyond the TEBL from operation of wet

[45] 40 CFR §122.44(l)
[46] 40 CFR §122.44(l)
[47] Personal communication with Shane Bynum, Permit Engineer in DEQ's Office of Water Quality

scrubbers using sodium hydroxide if there were no adverse environmental impact. However, FutureFuel did provide an alternative reagent for analysis of a wet scrubber. DEQ anticipates that the wet scrubbing scenario with lime slurry as the reagent would be similar in cost and control efficiency to sodium hydroxide wet scrubbing.[48] Therefore, DEQ considers FutureFuel's evaluation of wet scrubbing using lime slurry as sufficient for DEQ's assessment of both scrubbing reagent types.

FutureFuel also explained that low-NOx burners are not a technically feasible control technology for the three coal-fired boilers because there is no available or applicable low-NOx burner systems designed for stoker style boilers.[49]

b. Baseline Emission Rate

FutureFuel provided baseline SO_2 and NOx emissions for the three coal-fired boilers annualized on a maximum monthly emission rate for the period between 2017 and 2019. DEQ used the maximum monthly emissions rate to ensure that cost estimates for control technologies were based on appropriately sized equipment. In addition, DEQ calculated the average annual emissions during the 2017–2019 period to estimate the typical emission reductions that may be achievable from application of controls.[50] The average SO_2 baseline emissions for the three coal-fired boilers are 2,171 tons per year and the average NOx baseline emissions are 247 tons per year.

c. Control Effectiveness

Table V-12 summarizes the control effectiveness of each technically feasible emission reduction strategy evaluated in FutureFuel's response to DEQ's ICR and the estimated emission reductions that would be achieved if the strategy were implemented.

[48] See EPA's Air Pollution Control Cost Manual, Section 5. https://www.epa.gov/sites/production/files/2021-05/documents/wet_and_dry_scrubbers_section_5_chapter_1_control_cost_manual_7th_edition.pdf

[49] See EPA's Air Pollution Control Cost Manual, Chapter 1, Table 1.2, which identifies no available urea-based SNCR for stoker-fired boilers: https://www.epa.gov/sites/production/files/2017-12/documents/sncrcostmanualchapter7thedition20162017revisions.pdf See also Chapter 2 for information about SCR: https://cfpub.epa.gov/si/si_public_file_download.cfm?p_download_id=532813&Lab=OAQPS

[50] Average of annual emissions reported to the DEQ Emission Inventory team for years 2017 – 2019 for SN:6M01-01.

Table V-12: Control Effectiveness and Anticipated Annual Emission Reductions for Control Strategies Evaluated for FutureFuel Coal-Fired Boilers

Control Strategy		Control Effectiveness		Annual Emission Reductions (tpy)		
		SO_2	NOx	SO_2	NOx	Both
Fuel Switching from Coal to Natural Gas Strategies[51]	Retrofit 1 Boiler	33%	30%	716	74	790
	Replace 1 Boiler	33%	30%	716	74	790
	Retrofit all 3 Boilers	99%	90%	2,149	222	2,371
	Replace all 3 Boilers	99%	90%	2,149	222	2,371
SO_2 Scrubbing Strategies	Wet Scrubbers – Lime Slurry	94%	0%	2,041	0	2,041
	SDA	92%	0%	1,997	0	1,997
	DSI[52]	40%	0%	868	0	868
Fuel Switching to Lower Sulfur Coal Strategies	1.5% Sulfur Content Coal	44%	0%	966	0	966
	2% Sulfur Content Coal	27%	0%	591	0	591
	2.5% Sulfur Content Coal	10%	0%	215	0	215
NOx Post-Combustion Control Strategies	SCR	0%	80%	0	197	197
	SNCR	0%	40%	0	99	99

d. Cost of Compliance

DEQ made the following revisions to the cost of compliance estimates provided by FutureFuel to ensure compliance with the EPA Control Cost Manual:[53]

- Contingency costs were revised to twenty percent of total capital investment. The EPA Control Cost Manual suggests use of 20% of total capital investment for contingency for study level cost estimates and 5–15% for "mature control technologies." FutureFuel used 30% of capital costs (excluding energy and non-environmental capital costs that are part

[51] "Replace" means complete removal and replacement of older coal-fired equipment with new equipment that combusts natural gas; for details, see responses to DEQ's ICR provided by FutureFuel, located in Appendix G of this proposal. To "retrofit," FutureFuel would have to redesign and modify each boiler's coal fuel system to a natural gas fuel system. Each boiler would be designed to produce 50 KPPH steam using natural gas. According to FutureFuel's response, this design would change the dynamics so significantly that it would require a significant physical modification to the entire boiler system for the plant. FutureFuel estimated that it would take approximately one year for each Boiler retrofit to demolish the old feed system, install a new natural gas system, optimize the combustion criteria, check out the equipment, train operators, and then start up the modified unit.

[52] EPA's Menu of Control Measures estimates the control efficiency of DSI for industrial boilers burning high sulfur coal to be approximately 40%. https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation

[53] See revised cost-calculations provided in Appendix G and email from Philip Antici on July 23, 2020 in Appendix G.

of total capital investment) in their cost calculations without providing an explanation of why this change was appropriate due to site-specific considerations.

- AFUDC and Owner's costs, which are not valid costs under the EPA Control Cost Manual overnight estimation methodology were removed. EPA has noted that these costs were not consistent with the EPA Control Cost Manual in several actions on Planning Period I SIPs and FIPs.[54]
- All line-item costs estimated using total capital investment were revised to reflect changes in contingency and removal of the disallowed costs using formulas provided by the EPA Control Cost Manual.
  - Administrative costs = 2% of capital investment
  - Property tax = 1 % of capital investment
  - Insurance = 1% of capital investment
- Equipment life for control technologies was revised to be consistent with EPA control cost manual and similar technology assessments made during Regional Haze Planning Period I.
  - Wet FGD: 30 years
  - Dry FGD (SDA): 30 years
  - DSI: 30 years
  - SCR: 30 years
  - SNCR: 20 years
- The cost of fuel for natural gas scenarios was revised to reflect the incremental change in cost of using natural gas compared to coals currently in use for boilers based on EIA data. In addition, the cost associated with electrical, maintenance, operating and support labor, permitting and compliance were removed because these do not represent cost increases above the current cost of using coal.[55]
- The tax associated with the 1.5% coal control scenario was adjusted to remove cost of transportation from the taxable amount and costs were adjusted to reflect the incremental increase in cost above current stocks for each of the lower sulfur coal strategies (2.5%, 2%, and 1.5%).

Table V-13 summarizes the estimated costs for the control strategies evaluated for the three coal-fired boilers at FutureFuel under a 3.25% interest rate assumption. EPA Region 6 has indicated that DEQ should evaluate costs annualized based on the bank prime rate consistent with EPA Control Cost Manual guidance on private investments consistent with the EPA Control Cost

[54] EPA (2011). "Response to Technical Comments for Sections E through H of the Federal Register Notice for the Oklahoma Regional Haze and Visibility Transport Federal Implementation Plan," Docket No. EPA-R06-OAR-2010-0190.

[55] See email from Philip Antici on July 23, 2020 in Appendix G.

Manual, which is focused on "private cost" rather than "social costs."[56] EPA does not present the methodologies for social cost calculations in the EPA Cost Control Manual.[57]

The EPA Control Cost Manual recommends that assessments of private cost "should be prepared using firm-specific nominal interest rates, if possible, or the bank prime rate, if firm-specific interest rates cannot be estimated or verified."[58] Therefore, DEQ has calculated the annualized capital costs using the total capital investment estimates provided by FutureFuel and a 3.25% interest rate (bank prime rate on July 16, 2020). Table V-14 provides the cost-effectiveness of each of these strategies an annual average basis.

Table V-13: Estimated Cost of Control Strategies Evaluated for FutureFuel Coal-Fired Boilers

Control Strategy		Total Annual Cost ($/year)
Fuel Switching from Coal to Natural Gas	Retrofit 1 Boiler	2,895,785
	Replace 1 Boiler	9,065,215
	Retrofit all 3 Boilers	26,369,867
	Replace all 3 Boilers	26,430,503
SO_2 Scrubbing	Wet Scrubbers – Lime Slurry	11,088,595
	SDA	8,595,379
	DSI	6,662,059
Fuel Switching to Lower Sulfur Coal	1.5% Sulfur Content Coal	2,519,500
	2% Sulfur Content Coal	1,282,500
	2.5% Sulfur Content Coal	738,720
NOx Post-Combustion Control	SCR	4,969,353
	SNCR	2,186,559

Table V-14: Estimated Cost-Effectiveness of Control Strategies Evaluated for FutureFuel Coal-Fired Boilers

Control Strategy		Cost-Effectiveness ($/ton reduced)
Fuel Switching from Coal to Natural Gas[59]	Retrofit 1 Boiler	11,254
	Replace 1 Boiler	11,469
	Retrofit all 3 Boilers	11,120

[56] Email from Dayana Medina, EPA Region 6 dated July 16, 2020, which is included in Appendix D.
[57] EPA (2002). Chapter 2 - Cost Estimation: Concepts and Methodology. in "EPA Air Pollution Control Cost Manual (Sixth Edition)." Page 5 ("we will not present the methodologies for social cost calculations.")
[58] *Id.* at pages 2-15
[59] Cost-effectiveness represents cost per ton of SO_2 and NOx combined

	Replace all 3 Boilers	11,146
SO_2 Scrubbing	Wet Scrubbers – Lime Slurry	5,434
	SDA	4,303
	DSI	7,672
Fuel Switching to Lower Sulfur Coal	1.5% Sulfur Content Coal	2,774
	2% Sulfur Content Coal	2,171
	2.5% Sulfur Content Coal	3,430
NOx Post-Combustion Control	SCR	25,183
	SNCR	22,161

Two control strategies were cost-effective for FutureFuel based on DEQ's threshold for industrial boilers: fuel switching to two percent sulfur content coal and fuel switching to 1.5% sulfur content coal. The most cost-effective strategy is switching to two percent sulfur content coal. The incremental cost-effectiveness between two percent sulfur coal and one and one-half percent sulfur coal is above DEQ's threshold for industrial boilers. The costs of the other potential control strategies considered were above DEQ's threshold for industrial boilers.

e. Time Necessary for Compliance

Table V-15 provides a summary of the time that FutureFuel indicated would be necessary to comply with each of the assessed control technologies.

Table V-15: Time Necessary to Comply for Evaluated Control Strategies for FutureFuel

Control Strategy		Time Necessary to Comply	Basis
Fuel Switching from Coal to Natural Gas Strategies	Retrofit 1 Boiler	2 years	Time necessary for engineering design, DEQ approval, demolition of old feed system, installation of natural gas system, optimization, and logistics for shipping waste off-site
	Replace 1 Boiler	2 years	Time necessary for engineering design, DEQ approval, equipment build, delivery, construction, and logistics for shipping waste off-site
	Retrofit all 3 Boilers	4 years	Time necessary for engineering design, DEQ approval, demolition of old feed system, installation of natural gas system, optimization, and logistics for shipping waste off-site
	Replace all 3 Boilers	2.5 years	Time necessary for engineering design, DEQ approval, equipment build, delivery, construction, and logistics for shipping waste off-site
SO_2	Wet	6 years	Time necessary for engineering design, DEQ

Scrubbing Strategies	Scrubbers – Lime Slurry		review and approval, vendor and equipment selection, demolition of an existing building, purchase and installation of equipment, training, and start-up
	SDA	4 years	Time necessary for engineering design, DEQ review and approval, vendor and equipment selection, demolition or movement of an existing building, purchase and installation of equipment, training, and start-up
	DSI	3 years	Time necessary to for engineering design, DEQ review and approval, vendor and equipment selection, demolition or relocation of existing structures, delivery, construction, training, and startup.
Fuel Switching to Lower Sulfur Coal Strategies	1.5% Sulfur Content Coal	< 1 year	Time necessary to complete current contracts and exhaust existing coal stockpile
	2% Sulfur Content Coal	< 1 year	Time necessary to complete current contracts and exhaust existing coal stockpile
	2.5% Sulfur Content Coal	< 1 year	Time necessary to complete current contracts and exhaust existing coal stockpile
NOx Post-Combustion Control Strategies	SCR	4 years	Time necessary for engineering design, DEQ review and approval, vendor and equipment selection, demolition or movement of an existing building, purchase and installation of equipment, training, and start-up
	SNCR	4 years	Time necessary for engineering design, DEQ review and approval, vendor and equipment selection, demolition or movement of an existing building, purchase and installation of equipment, training, and start-up

f. Energy and Non-Air Quality Impacts

FutureFuel reported energy and non-environmental impacts for each of the assessed technologies. Impacts of each technology are summarized below.

With the exception of the fuel-switching to lower sulfur coal options, all strategies assessed would have both energy and waste impacts for FutureFuel. FutureFuel recovers and burns solvent waste that cannot be reused in the coal-fired boilers. These wastes residues assist in steam production and reduce the amount of coal combustion necessary. Retrofitting or replacing the coal-fired boilers with natural gas would render FutureFuel unable to use the solvent wastes to produce steam and would require FutureFuel to ship the waste, including hazardous waste, offsite. Retrofitting or replacing just one of the three boilers would reduce FutureFuel's capacity to recover solvent wastes and result in some off-site waste disposal. SCR, SNCR, DSI, wet scrubbers, and spray dry absorbers would require the boilers to be temporarily taken offline and require disposal of solvent wastes during the offline period. The costs associated with the impacts of each assessed technology on waste energy recovery is factored into the cost of compliance reported by FutureFuel.

Implementation of a wet scrubbing, spray dry absorption, or DSI would result in waste disposal costs, which have been factored into the cost of compliance.

Fuel-switching to any of the lower sulfur coal options identified would not be expected to yield any energy or non-air quality impacts so long as the coal used meets the coal heating value and fusion temperature requirements of the boilers.

FutureFuel did not identify any energy and non-air quality impacts for the implementation of SCR or SNCR other than the impacts to waste energy recovery noted above during installation of the technologies.

g. Remaining Useful Life of the Source

There is no enforceable limitation on the useful life of the three coal-fired boilers. Therefore, FutureFuel used the equipment life of the control technologies evaluated found in the EPA Pollution Control Cost Manual to annualize total capital investment for each control strategy assessed.

h. Visibility Considerations

The 2016 results from the Ramboll AOI study indicate that emissions from FutureFuel are anticipated to contribute to visibility impairment at Upper Buffalo and Hercules Glades.[60] FutureFuel's 2016 impact on federal Class I areas was less than six other point sources for Upper Buffalo and less than eleven other point sources for Hercules Glades according to the 2016 AOI analysis. FutureFuel's impact at Caney Creek, Mingo, and Sipsey is less than one percent of the total sum of surrogate values for all point sources. These five Class I areas are on track to make greater progress than the URP glidepath in 2028 before consideration of potential controls for

[60] The FutureFuel visibility surrogate value was 3% of the total sum of surrogate values for all point sources in the 2016 inventory for Upper Buffalo and 2% for Hercules Glades.

FutureFuel. FutureFuel is not within the nitrate or sulfate-specific area of influence for Mammoth Cave or Wichita Mountains based on the 0.05% threshold. FutureFuel was not identified as a source reasonably anticipated to contribute to visibility impairment at other federal Class I areas by modeling from other RPOs.

i. Proposed Decision on Control Measures Necessary to Make Reasonable Progress

In determining whether potential control measures are necessary for FutureFuel during Planning Period II, DEQ weighs the four statutory factors and visibility considerations. The time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life have been factored into the cost of compliance for the potential control strategies considered for FutureFuel. In examining the two cost-effective strategies—fuel switching to 2% sulfur content coal and fuel switching to 1.5% sulfur content coal—DEQ considers both the incremental cost-effectiveness of the more stringent option, 1.5% sulfur content coal, and the relative impact of FutureFuel on visibility impairment at federal Class I areas. Fuel switching to 2% sulfur content coal is the most cost-effective in terms of $/ton; further, the incremental cost-effectiveness of switching to 1.5% sulfur content coal versus switching to 2% sulfur content coal exceeds DEQ's threshold for industrial boilers.

Furthermore, federal Class I areas for which FutureFuel is within the nitrate- or sulfate-specific area of influence are on track to make greater progress than the URP glidepath in 2028 before consideration of addition of controls for FutureFuel. Although the URP is not determinative as to whether a control is reasonable after consideration of the four factors, being below the URP glidepath means that the additional demonstrations under 40 C.F.R. 51.308(f)(3)(ii) are not required.

After consideration of the statutory factors and visibility considerations, DEQ has determined that an emission limit for FutureFuel's coal-fired boilers based on fuel switching to 2% sulfur content coal is reasonable to ensure continued progress toward natural visibility conditions at federal Class I areas during Planning Period II. In addition, DEQ proposes to enter into an administrative order with FutureFuel that would render the 2% sulfur coal content and resulting emission limit enforceable by DEQ and, upon approval, by EPA as part of the SIP. A draft version of the proposed administrative order has been included in Appendix G for public review. Prior to submission to EPA, a final administrative order that incorporates any changes in response to public comment must be signed by DEQ and FutureFuel to render the requirements enforceable as a matter of state law.

5. Domtar Ashdown Mill

The Ashdown Mill is a pulp and paper mill owned by Domtar A.W. LLC located in Little River County, Arkansas. Ashdown Mill has four emission units that emit over 100 tpy of NOx: No. 2 Power Boiler (SN-05), No. 3 Power Boiler (SN-01), No. 2 Recovery Boiler (SN-06), and No. 3

Recovery Boiler (SN-14). Two of those units also emit over 100 tpy of SO_2: No. 2 Power Boiler (SN-05) and No. 3 Power Boiler (SN-01). Combined, these four emission units emit the majority of SO_2 and NOx from Ashdown Mill.

Both the No. 2 and No. 3 Power Boilers primarily burn clean cellulosic biomass (bark) and natural gas. The No. 2 Power Boiler additionally burns coal. Both boilers are identified as hybrid suspension/grate burners under 40 CFR 63 Subpart DDDDD. The No. 3 Power Boiler has a moving grate, combustion air system including over fire air, and a two-chamber dry electrostatic precipitator (ESP). The No. 2 Power Boiler is equipped with a traveling grate, combustion air system including over fire air, multiclones, and two venturi scrubbers in parallel.

Both No. 2 and No. 3 Power Boilers function as swing load boilers, responding to changes in demand for steam from the various process area users. The Ashdown Mill operates three separate pulping lines (of which two are batch processes), three separate bleach plants, two separate evaporator units, and currently two finished product lines. Any changes in steam demand from the process areas is accommodated through an associated swing in load on either or both of the power boilers to avoid further upsets in the steam header control systems. The recovery boilers are typically base-loaded to protect the chemical recovery process and avoid upsets in the liquor cycle and inventory. The mill consistently experiences variable process steam requirements due to the number of different process areas in operation. It is common to experience steam demand swings on both power boilers in the range of 100,000 – 300,000 lb/hr on any given operating day. There are also seasonal variations that impact steam demand, as well as varying fuel moisture content (primarily due to wet bark or coal).

The No. 3 Power Boiler flue gas exhaust temperatures are low, similar to No. 2 Power Boiler. No. 2 Power Boiler is slightly lower due to the venturi scrubber. No. 3 Power Boiler is a little higher due to the associated dry (ESP). Both boilers typically operate with high excess percent of O_2, in the range of 10%.

No. 3 Power Boiler is located just to the North of No. 2 Power Boiler.[61] There is a bark distribution and feed system located between the two boilers, as well as building structure that houses various motor control centers for both boiler's operating equipment, auxiliary equipment, and a control room. The No. 3 Power Boiler is adjacent to the No. 2 Recovery Boiler unit just to the North. These factors provide very similar space constraints as have been identified with the No. 2 Power Boiler in Domtar's ICR response.

No. 2 Power Boiler has a design heat input rate of 820 MMBtu/hr and is capable of burning a variety of fuels including clean cellulosic biomass, coal, tire derived fuel, natural gas, wood chips used to absorb oil, and petroleum coke. The unit is equipped with two Venturi scrubbers for removal of particulates and SO_2. No. 2 Power Boiler was subject to BART for Regional Haze Planning Period I. Based on the BART analyses for this unit, EPA established a BART limit of

[61] See Domtar's ICR response, facility layout map, in Appendix H.

91.5 lb SO_2/hr 345 lb NOx/hr for this unit. The SO_2 BART limit was based on utilization of additional reagent in the existing Venturi scrubbers installed for No. 2 Power Boiler. The NOx BART limit was based on no new controls for NOx. In 2019, DEQ finalized an alternative to BART for this unit and No. 1 Power Boiler based on changes in operations at Ashdown Mill. This alternative to BART achieved greater visibility progress than the 2016 FIP BART limits.

The BART alternative limits for Domtar Ashdown Mill No. 1 Power Boiler are 0.5 lbs/hr for SO_2 and 191.1 lbs/hr for NOx. The BART alternative limits for Domtar Ashdown Mill No. 2 Power Boiler are 425 lbs/hr for SO_2 and 293 lbs/hr for NOx. These limits are specified in both the Title V permit for the facility and in the Arkansas Regional Haze SIP revision approved by EPA and effective on April 12, 2021, and therefore, federally-enforceable.[62]

No. 3 Power Boiler was a recovery boiler converted to a power boiler in 1990-91. It has a design heat input rate of 790 MMBtu/hr and is capable of burning a variety of fuels including clean cellulosic biomass, bark and wood chips used to absorb oil spills, wood waste, tire derived fuel, and natural gas. No. 3 Power Boiler has no existing combustion or post-combustion controls for NOx or SO_2.

No. 2 Recovery Boiler has a heat input capacity of 1,160 MMBtu/hr and combusts black liquor solids to recover inorganic chemicals and natural gas. No. 2 Recovery Boiler has existing no combustion or post-combustion controls for NOx or SO_2 listed in the permit for Ashdown Mill.

No. 3 Recovery Boiler has a heat input capacity of 1,088 MMBtu/hr and combusts black liquor solids to recover inorganic chemicals and natural gas. No. 3 Recovery Boiler has existing no combustion or post-combustion controls for NOx or SO_2 listed in the permit for Ashdown Mill.

Domtar employs good operating practices for both No. 2 and No. 3 Recovery Boilers. These practices include optimization of liquor properties and combustion air fire patterns to reduce SO_2 and NOx emissions.

On January 8, 2020, DEQ sent an information collection request to Domtar, asking for information about potential emission reduction strategies for these emission units at Ashdown Mill. Specifically, DEQ requested information about the technical feasibility and cost of the following SO_2 and NOx emission reduction strategies:

- SO_2 (ranked from highest control efficiency to lowest)[63]
  - For SN-05
    - Installation of new add-on scrubbers operating downstream of the existing scrubbers (typical control efficiency for industrial coal-fired boilers ≈

[62] Permit No.0287-AOP-R23 https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/0287-AOP-R23.pdf

[63] EPA Menu of Control Measures https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation

ninety to ninety-five percent control efficiency for industrial coal-fired boilers)
    - Increasing the SO_2 control efficiency of the existing scrubbers from current levels to ninety percent through the use of additional scrubbing reagent
    - Upgrades to the existing scrubbers
  - For SN-01
    - Installation of a wet gas scrubber (typical control efficiency for industrial coal-fired boilers ≈ ninety to ninety-nine percent)
    - Installation of a SDA (typical control efficiency for industrial coal-fired boilers ≈ ninety to ninety-five percent);
- NOx (ranked from highest control efficiency to lowest) for all units[64]
  - Selective Catalytic Reduction (typical control efficiency ≈ eighty percent for industrial boilers coal and ninety percent for industrial boilers wood/bark/waste)
  - Regenerative Selective Catalytic Reduction (typical control efficiency ≈ seventy-five percent for industrial boilers wood/bark/waste)
  - Selective Non-Catalytic Reduction (typical control efficiency ≈ forty percent for industrial boilers coal).

A copy of the information request letter is included in Appendix H.

On April 6, 2020, Domtar submitted the requested information to DEQ. This response is included in Appendix H. After reviewing Domtar's April 6, 2020 response, DEQ requested updates to certain emission reduction assumptions included in the response based on actual hours operated during the baseline. DEQ also requested that Domtar provide emission reduction and cost-effectiveness estimates based on an average emission rate for the baseline period in addition to estimates based on the maximum month emission rate. On May 7, 2020, Domtar submitted the updated information that DEQ requested. The revised response is also included in Appendix H. After review of the information provided by Domtar, DEQ made the following revisions to control efficiency and cost assumptions for consistency with the EPA control cost manual and to reflect existing controls on No. 2 Power Boiler.[65]

a. Technical Feasibility of Identified Control Strategies

For No. 2 Power Boiler, the following controls measures were considered technically feasible: the addition of a new downstream scrubber, increased reagent usage for the existing venturi scrubbers, and SNCR. SCR was determined to be technically infeasible for No. 2 Power Boiler in a previous analysis submitted for Planning Period I. Regenerative SCR has not been

[64] EPA Menu of Control Measures https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation

[65] See Domtar revised cost calculations and email from Kelly Crouch on July 24, 2020 in Appendix H.

successfully implemented on an emission unit comparable to No. 2 Power Boiler. In addition, the space and temperature constraints for No. 2 Power Boiler make regenerative SCR technically infeasible.

While SNCR is technically feasible for No. 2 Power Boiler, Domtar explained that the emission reduction capability of this technology as applied to No. 2 Power Boiler is limited due to the wide variability in temperature at No. 2 Power Boiler.

No. 3 Power Boiler is similar in design and operation profile to No. 2 Power Boiler. Therefore, the technologies considered technically infeasible for No. 2 Power Boiler (SCR and regenerative SCR) are also technically infeasible for No. 3 Power Boiler. No. 3 Power Boiler also has similar limitations with the control efficiency of SNCR. No. 3 Power Boiler does not have existing scrubbers. Therefore, the technically feasible control technologies for No. 3 Power Boiler include Wet FGD, SDA, and SNCR. Domtar's report also describes the inherent scrubbing properties of ash created from combusting bark in the boiler. This inherent scrubbing is an existing control that captures some of the sulfur dioxide when co-firing of sulfur-containing fossil fuels and is represented in the baseline emission rate.

None of the identified control technologies were technically feasible for No. 2 and No. 3 Recovery Boilers. Based on information available in the EPA RACT/BACT/LAER Clearinghouse, the National Council for Air and Stream Improvement information, and Trinity Consultants' library of air pollution control assessments, Domtar concluded that flue gas desulfurization, SCR, and SNCR are not technically feasible.[66] FGD was determined not to be technically feasible because it is capital-intensive, and energy-intensive, and its efficacy is unproven, considering the generally low but rapidly fluctuating levels of SO_2 in kraft recovery furnace flue gases.[67]

An RBLC query indicates that SCR and SNCR are infeasible on recovery boilers as no determinations for these technologies on recovery boilers were found. Recovery boilers produce complex chemical reactions, and disruptions to the reaction chemistry could potentially damage the furnace, impact the quality of the product, or otherwise unacceptably affect the system. Additionally, kraft recovery boilers operate at varying loads that make it difficult to inject SNCR reagent within the desired temperature window.[68] Because SCR and SNCR have not been

[66] NCASI Handbook of Environmental Regulations and Control, Volume 1: Pulp and Paper Manufacturing, April 2013, Section 6.8.3.3; RBLC searches were completed on February 3, 2020 for Process Types 30.211, 30.219, 30.290, 11.190, 11.290, and 11.900 and for process names that include the word "recovery."

[67] Appendix H, Trinity Consultants Report: Response to January 8, 2020 Regional Haze Four-Factor Analysis Information Collection Request, p 6-1

[68] NCASI Handbook of Environmental Regulations and Control, Volume 1: Pulp and Paper Manufacturing, April 2013, Section 6.8.3.4

applied to recovery boilers, these technologies are not considered feasible for Recovery Boilers 2 and 3.[69]

Because no technically feasible control technologies were identified for No. 2 Recovery Boiler and No. 3 Recovery Boiler, DEQ finds it unnecessary to perform an analysis for these emission units.

b. Baseline Emission Rate

Domtar provided a baseline emission rates for No. 2 Power Boiler and No. 3 Power Boiler annualized on both a maximum monthly emission rate basis and an average monthly emission rate basis from the baseline period of 2017–2019. DEQ used the annualized baseline emission rate based on maximum monthly emissions to ensure that cost estimates for control technologies were based on appropriately sized equipment. DEQ used the annualized baseline emissions rate based on average monthly emissions to estimate the typical emission reductions that may be achievable from application of controls. The average baseline emissions for No. 2 Power Boiler and No. 3 Power Boiler are presented in Table V-16.

Table V-16: Annualized Baseline Emissions for Ashdown Mill No. 2 Power Boiler and No. 3 Power Boiler (Average Month Basis)

Emission Unit	SO_2 Baseline Emissions (tpy)	NOx Baseline Emissions (tpy)
No. 2 Power Boiler	858.9	559.9
No. 3 Power Boiler	46.9	290.1

c. Control Effectiveness

Table V-17 summarizes the control effectiveness of each technically feasible emission reduction strategy evaluated for No. 2 Power Boiler and No. 3 Power Boiler in Domtar's response to DEQ's ICR. Domtar's response to DEQ's ICR indicated that no emissions reductions are possible from upgrades to the existing scrubbers. Therefore, no further evaluation of the existing scrubber upgrades strategy is included in this analysis.

Table V-17: Control Effectiveness and Anticipated Annual Emission Reductions for Control Strategies Evaluated for Ashdown Mill No. 2 Power Boiler and No. 3 Power Boiler

Emission Unit	Control Strategy	Pollutant	Control Efficiency	Controlled Emission Rate (tpy)	Emission Reductions (tpy)
No. 2	New downstream scrubber	SO_2	90%	85.9	773

69 Appendix H, Trinity Consultants Report: Response to January 8, 2020 Regional Haze Four-Factor Analysis Information Collection Request, p 7-2

Power Boiler	Increased reagent usage at existing scrubbers	SO_2	90%[70]	279.8	579.1
	SNCR (Scenario 1)	NOx	3%	543.1	16.8
	SNCR (Scenario 2)	NOx	27.5%	406	154
No. 3 Power Boiler	Wet FGD	SO_2	90%	4.7	42.2
	Dry FGD	SO_2	90%	4.7	42.2
	SNCR (Scenario 1)	NOx	3%	281.4	8.7
	SNCR (Scenario 2)	NOx	27.5%	210.3	79.8

Domtar's estimate of three percent control effectiveness of SNCR for NOx emissions (Scenario 1) is lower than the typical control efficiency of this technology due to unit-specific constraints for No. 2 Power Boiler and No. 3 Power Boiler. Domtar explains that this low control effectiveness is because of the temperature variability inherent in their operation of these power boilers. Domtar performed a study to analyze temperature variability of No. 2 Power Boiler. Based on this study, Domtar estimates that the SNCR would achieve forty percent emission reductions during the seven percent of operations during which the SNCR system could be operated under optimal conditions. DEQ also performed a sensitivity case using the 27.5% control efficiency assumption used in the EPA 2016 FIP (Scenario 2). Domtar has asserted that this control efficiency is unrealistic given the operating characteristics of No. 2 Power Boiler and could result in stack emissions of 1,700 tons or more per year of unreacted urea.[71] These assumptions are also applicable to No. 3 Power Boiler which has similar variability in exit gas temperature that limits when an SNCR system can function.

d. Cost of Compliance

DEQ has revised the cost estimates for No. 2 Power Boiler and No. 3 Power Boiler provided by Domtar in their responses to DEQ's ICR as follows:[72]

- The interest rate for annualizing capital costs was revised from 7% to 3.25%;
- DEQ has revised cost-effectiveness of increasing scrubbing reagent for the existing scrubber based on the anticipated emission reductions calculated using the formulas EPA used in AR020.0188 Domtar PB2_Cost 2011-2013;
- DEQ revised cost calculations for SNCR to reflect the system operation scenario presented by Domtar (Scenario 1);
- DEQ has also calculated the cost of SNCR under the control efficiency and operational

[70] Total control efficiency of existing scrubbers after increasing reagent usage is estimated to be 90%. The baseline emissions for No. 2 Power Boiler represents approximately 69% control efficiency from the existing scrubbers. Adding additional reagent to achieve the maximum control efficiency of the existing scrubber is estimated to reduce baseline emissions by 67%. See Domtar revised cost calculations spreadsheet in Appendix H.

[71] Email from Kelley Crouch on July 24, 2020 in Appendix H.

[72] See spreadsheet Domtar Revised Cost Calculations in Appendix H.

assumptions that EPA used in the 2016 FIP (Scenario 2) for comparison with Scenario 1; and

- Costs have been escalated to 2019 dollars using the Chemical Engineering Plant Cost Index.

Table V-18 provides estimated cost of each control strategy and cost-effectiveness in $/ton.

Table V-18: Estimated Cost and Cost-Effectiveness of Control Strategies Evaluated for Ashdown Mill No. 2 Power Boiler and No. 3 Power Boiler in 2019 Dollars

Emission Unit	Control Strategy	Total Annual Cost ($/year)	Cost-effectiveness ($/ton)
No. 2 Power Boiler	New downstream scrubber	10,151,897	13,133
	Increased reagent usage at existing scrubbers	2,077,763	3,590
	SNCR (Scenario 1)	314,019	20,030
	SNCR (Scenario 2)	985,072	25,129
No. 3 Power Boiler	Wet FGD low estimate	2,551,376	60,459
	Wet FGD high estimate	11,656,785	276,227
	Dry FGD low estimate	3,110,337	73,705
	Dry FGD high estimate	45,980,612	1,089,588
	SNCR (Scenario 1)	314,019	38,659
	SNCR (Scenario 2)	985,072	12,348

The $/ton values for each control strategy evaluated for No. 2 and No. 3 Power Boiler exceed DEQ's threshold for industrial boilers.

e. Time Necessary for Compliance

Table V-19 summarizes the time Domtar estimates would be necessary to comply with an emission limit based on the assessed technologies for No. 2 Power Boiler and No. 3 Power Boiler.

Table V-19: Time Necessary to Comply for Evaluated Control Strategies for Ashdown Mill No. 2 Power Boiler and No. 3 Power Boiler

Emission Unit	Control Strategy	Time Necessary to Comply	Basis
No. 2 Power Boiler	New downstream scrubber	3 years	34 week shipment and construction period; 18 month outage frequency for No. 2 Power Boiler

	Increased reagent usage at existing scrubbers	2 years	Time needed to procure and install two new pumps and 18 month outage frequency for No. 2 Power Boiler
	SNCR	5 years	Precedent in Utah and North Dakota FIPs
No. 3 Power Boiler	Wet FGD	5 years	Determinations for utilities in other SIPs for Planning Period I
	SDA	5 years	Determinations for utilities in other SIPs for Planning Period I
	SNCR	5 years	Precedent in Utah and North Dakota FIPs

f. Energy and Non-Air Quality Impacts

Domtar reported that installation of a new scrubber downstream of the existing scrubber would result in increased water usage and wastewater generation and impact energy needs for Ashdown Mill. These considerations are factored into the reported cost of compliance with this technology.

Domtar reported that energy and non-air quality environmental impacts of increased reagent usage at the existing scrubbers are expected to be minimal.

Domtar does not expect that energy impacts or non-air quality environmental impacts for SNCR would be greater for No. 2 Power Boiler and No. 3 Power Boiler than at any other industrial facility under the operational scenario presented. Under the 2016 FIP operational scenario, Domtar estimates that 1,700 tons or more of unreacted urea would be emitted through the stack for No. 2 Power Boiler if an SNCR was operated during the ninety-three percent that the boiler is operated outside the optimal temperatures required for SNCR.[73]

g. Remaining Useful Life of the Source

Domtar has no plans to cease operations of No. 2 Power Boiler or No. 3 Power Boiler. The useful life values for control equipment assessed in EPA's Control Costs Manual were assumed in amortizing capital costs for the purposes of annualizing capital costs.

h. Visibility Considerations

The 2016 results from the Ramboll AOI study indicate that emissions from Ashdown Mill are anticipated to contribute to visibility impairment at Caney Creek.[74] Ashdown Mill's 2016 visibility surrogate for Caney Creek was less than five other point sources according to the 2016 AOI analysis. Caney Creek is on track with the URP glidepath in 2028 before consideration of

[73] Email from Kelley Crouch on July 24, 2020 in Appendix H.

[74] Domtar Ashdown Mill's visibility surrogate value was 5% of the total sum of surrogate values for all point sources in the 2016 inventory for Caney Creek.

potential controls for Ashdown Mill. Ashdown Mill's visibility surrogate is less than one percent of the total sum of surrogate values for all point sources for Hercules Glades, Upper Buffalo, and Wichita Mountains. Ashdown Mill is not within the nitrate- or sulfate-specific area of influence for Mammoth Cave, Mingo, or Sipsey based on the 0.05% threshold. Ashdown Mill was not identified as a source reasonably anticipated to contribute to visibility impairment at other federal Class I areas by modeling from other RPOs.

i. Proposed Decision on Control Measures Necessary to Make Reasonable Progress

In determining whether potential control measures are necessary for Ashdown Mill during Planning Period II, DEQ weighs the four statutory factors and visibility considerations. The time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life have been factored into the cost of compliance for the potential control strategies considered for Ashdown Mill. All of the control strategies evaluated for Ashdown Mill exceed DEQ's cost threshold for industrial boilers. Furthermore, Ashdown Mill has a smaller impact on federal Class I areas relative to other point sources and the primary federal Class I area impacted by Ashdown Mill is on track with the URP glidepath in 2028 before consideration of potential controls for Ashdown Mill. Although the URP is not determinative in making a decision with respect to whether a control is reasonable after consideration of the four factors, being below the URP glidepath means that the additional demonstrations under 40 C.F.R. 51.308(f)(3)(ii) are not required. After consideration of the statutory factors and visibility considerations, DEQ has determined that no additional controls are necessary for Ashdown Mill to make reasonable progress during Planning Period II.

6. Flint Creek Power Plant

The Flint Creek Power Plant (Flint Creek) is a coal-fired electric generating station located in Benton County, Arkansas. Flint Creek has one 558 megawatt dry bottom wall-fired boiler. The boiler burns low sulfur western coal as a primary fuel, but it can also combust fuel oil and tire-derived fuels.

The Flint Creek boiler is equipped with low-NOx burners with separated overfire air to control NOx emissions, dry flue gas desulfurization with pulse jet fabric filter and activated carbon injection to control SO_2 emissions, and electrostatic precipitators to control particulate matter emissions. The Flint Creek boiler is subject to an emission limit of 0.06 lb SO_2/MMBtu on a thirty-day rolling average. The low-NOx burners with over-fire air achieve an emission rate of 0.23 lb/MMBtu or less. The SO_2 limit is contained in the Arkansas SIP, and the NOx limit, based on the use of low-NOx burners is contained in a federally-enforceable Title V permit.[75] The low

[75] Permit #0276-AOP-R9 https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/0276-AOP-R9.pdf

NOx burners are an inherent part of equipment design (i.e., cannot be shut down temporarily, as is the case with a post-combustion control). Based on the existing controls and emission limits contained in the Title V permit, DEQ determined that no further analysis of potential controls for SO_2 was necessary for this planning period.[76]

On January 8, 2020, DEQ sent an ICR to Southwestern Power Company (SWEPCO), a subsidiary of American Electric Power Service Company, asking for information about potential emission reduction strategies for Flint Creek Boiler 1. Specifically, DEQ requested information about the technical feasibility and cost of two potential post-combustion NOx reduction strategies: SCR and SNCR. A copy of the information request letter is included in Appendix I.

On March 25, 2020, SWEPCO submitted the requested information to DEQ. This letter is included in Appendix I. DEQ's evaluation of potential control strategies for Flint Creek are based on the information contained in SWEPCO's response.

a. Technical Feasibility of Identified Control Strategies

Both SCR and SNCR were considered technically feasible.

b. Baseline Emission Rate

SWEPCO reported baseline emissions for NOx on both a maximum month basis and average month basis for the period between June 1, 2018 and December 31, 2019. The period included in the baseline represents operations after the low-NOx burners were installed at Flint Creek in 2018.[77] DEQ used the maximum monthly emission rate to ensure that control technology evaluated is adequately sized for the purposes of control cost calculations. DEQ used the average monthly baseline emission rate to estimate typical emission reductions that can be anticipated from the application of a control strategy. The average baseline NOx emissions were 2,868 tons per year.

c. Control Effectiveness

Both SCR and SNCR were recently evaluated as potential BART technologies for EPA's 2016 FIP. In the analysis supporting the 2016 FIP, a controlled emission rate of 0.055 lb NOx/MMBtu was estimated for SCR and a controlled emission rate of 0.20 lb NOx/MMBtu was estimated for

[76] EPA guidance instructs states that it is unlikely that an analysis of control measures would conclude that an even more stringent control is necessary is necessary to make reasonable progress for a coal-fired power plant that is already equipped with a scrubber and meeting an emission limit less than 0.2 lb SO_2/MMBtu. See EPA (2019) "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" at page 23. https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf

[77] Construction of low-NOx burners with separated overfire air was completed on May 8, 2018.

SNCR. These controlled emission rate estimates represent a 72.5% emission reduction for SCR and no reduction for SNCR from the baseline maximum rate. However, the controlled emission rate used for SNCR with LNB/SOFA in the 2016 FIP was a middle value in a range of vendor estimated controlled emission rates (0.18–0.23). Furthermore, some degree of emission reduction would be anticipated from installation of SNCR. However, the control efficiency percent for SNCR decreases with decreasing inlet NOx concentrations. Therefore, DEQ expects that the control effectiveness of adding a SNCR system for Flint Creek would be well below the typical control efficiency for SNCR.[78]

For LNB/OFA alone, the controlled emission rate was estimated at 0.23 lb/MMBtu in the 2016 FIP. This value was in the upper end of the range (0.18–0.23) of expected controlled emission rates provided by the vendor for LNB/OFA. In practice, Flint Creek has achieved an even lower emission rate after installation of LNB/OFA (0.20 lb/MMBTU on a maximum month basis and 0.186 lb/MMBTU on an average month basis).

The difference in control efficiency between the two estimated controlled emission rates (LNB/OFA and LNB/OFA/SNCR) is ten percent. Additionally, the difference between the maximum monthly NOx emission rate during the baseline (0.20 lb/MMBTU) and the lower range of controlled emission rates provided by the vendor for LNB/OFA/SNCR (0.18 lb/MMBTU) would result in a 10% emission reduction. Therefore, an inlet emission rate of 0.20 lb/MMBTU and a control efficiency of 10% is appropriate to use for determining costs to ensure that the system is adequately sized to accommodate maximum inlet concentrations.

The difference between the average monthly emission rate during the baseline (0.186 lb/MMBTU) and a controlled emission rate of 0.18 lb/MMBTU is 3.22%. Therefore, DEQ estimates that Flint Creek could achieve up to a 3.22% emission reduction from baseline emissions if SNCR were installed.

d. Cost of Compliance

DEQ has revised the cost estimates for Flint Creek provided by SWEPCO in their responses to DEQ's ICR as follows:[79]

- DEQ revised the interest rate used to annualize capital costs from 7% to 3.25%;
- DEQ revised cost calculations for SNCR to reflect the maximum NOx inlet rate and a ten percent maximum control efficiency; and

[78] EPA's Menu of Control Measures lists a typical control efficiency of 90% for SCR and 35–50% for SNCR. These control efficiencies presume that no other NOx control systems are in place and are intended to provide a "ball park" starting point for control efficiency and cost. Flint Creek recently installed low-NOx burners, which resulted in 35% reduction in emissions.

[79] See spreadsheet Flint Creek Revised Cost Calculations in Appendix I.

- DEQ escalated costs to 2019 dollars using the Chemical Engineering Plant Cost Index.

Table V-20 summarizes the estimated costs and cost-effectiveness for the control strategies evaluated for Flint Creek

Table V-20: Estimated Cost of Control Strategies Evaluated for Flint Creek in 2019 Dollars

Control Strategy	Total Annual Cost ($/year)	Cost-Effectiveness ($/ton)
SCR	11,657,668	5,771
SNCR	604,515	6,790

Both control strategies evaluated for Flint Creek exceed DEQ's threshold for EGU Boilers.

e. Time Necessary for Compliance

DEQ expects that the time necessary for compliance with either SCR or SNCR would be three years after EPA approval of such a control technology into the Arkansas SIP. This time estimate is based on the time SWEPCO reported would be necessary to complete engineering design, procurement, construction, and shakedown.

f. Energy and Non-Air Quality Impacts

SWEPCO reported that installation and operation of SCR for Flint Creek would create additional parasitic load due to the electricity requirements of SCR system equipment. To produce an equivalent amount of net generation, additional fuel would be required thus increasing the cost of generation and emission of other pollutants not controlled by the SCR system.

Both SCR and SNCR systems utilize ammonia, which is dangerous at high concentrations, as part of the chemical reaction used to reduce NOx emissions. The risk of accidental release during transport and storage; therefore, must be managed. In addition, unreacted ammonia may be emitted to the atmosphere from SCR and SNCR systems under certain conditions and react with sulfates and nitrates to form visibility-impairing particles, i.e., ammonium sulfate and ammonium nitrate.

The anticipated costs on energy and non-air quality impacts for each system are factored into the cost of compliance.

g. Remaining Useful Life of the Source

Flint Creek is not under any state- or federally-enforceable requirement that would limit the life of Boiler 1. Therefore, EPA's default life values for SCR (30 years) and SNCR (20 years) were used by SWEPCO in quantifying the cost of compliance with these technologies.

h. Visibility Considerations

The 2016 results from the Ramboll AOI study indicate that emissions from Flint Creek are anticipated to contribute to visibility impairment at Hercules Glades and Upper Buffalo.[80] Flint Creek's 2016 visibility surrogate was less than fourteen other point sources for Hercules Glades and was less than 11 other point sources for Upper Buffalo according to the 2016 AOI analysis. Both Class I areas on track with the URP glidepath in 2028 before consideration of potential controls for Flint Creek. Flint Creek's visibility surrogate is less than one percent of the total sum of surrogate values for all point sources for Caney Creek. Flint Creek is not within the nitrate- or sulfate-specific area of influence for Mammoth Cave, Mingo, Sipsey, or Wichita Mountains based on the 0.05% threshold. Flint Creek was not identified as a source reasonably anticipated to contribute to visibility impairment at other federal Class I areas by modeling from other RPOs.

i. Proposed Decision on Control Measures Necessary to Make Reasonable Progress

In determining whether additional control measures are necessary for Flint Creek during Planning Period II, DEQ weighs the four statutory factors and visibility considerations. The time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life have been factored into the cost of compliance for potential controls considered for Flint Creek. Flint Creek is already well controlled for NOx and SO_2, having recently installed controls for both pollutants. The cost of the additional potential controls considered for Flint Creek exceed DEQ's cost threshold for EGU boilers. Furthermore, federal Class I areas for which Flint Creek is within the nitrate- or sulfate-specific area of influence are on track to make greater progress than the URP glidepath in 2028 before consideration of additional controls at Flint Creek. Although the URP is not determinative in making a decision with respect to whether a control is reasonable after consideration of the four factors, being below the URP glidepath means that the additional demonstrations under 40 C.F.R. 51.308(f)(3)(ii) are not required. After consideration of the statutory factors and visibility considerations, DEQ has determined that no additional controls are necessary for Flint Creek during Planning Period II.

D. Share of Emission Reduction Obligations from Other States Impacting Arkansas Federal Class I Areas

Using the 2016 AOI analysis, DEQ has quantified the relative contribution of Arkansas sources to federal Class I areas in other states.[81] The AOI analysis indicates that Arkansas sources have a relatively small impact on federal Class I areas in other states with the exception of Hercules Glades in Missouri. Arkansas's relative impact compared to other states, based on the 2016 AOI

[80] Flint Creek's visibility surrogate value was 1% of the total sum of surrogate values for all point sources in the 2016 inventory for Hercules Glades and Upper Buffalo.

[81] See Chapter III.

analysis is two percent for Sipsey in Alabama, four percent for Mingo in Missouri, and less than one percent for Mammoth Cave and Wichita Mountains.

In addition, DEQ brought forth for further analysis each Arkansas source included when using a threshold of seventy percent of cumulative percentage of 2016 AOI Impacts for NOx and SO_2 combined for all federal Class I areas included in the AOI analysis.

DEQ also received a request from the VISTAS on behalf of North Carolina to perform a four-factor analysis on Entergy Independence. VISTAS conducted photochemical modeling with particulate source apportionment technology using projected 2028 emissions to identify sources that should undergo a reasonable progress analysis. The VISTAS "ask" letter and other correspondence between DEQ, VISTAS, and North Carolina on this matter are included in Appendix D.

No specific controls were requested from any other state, including those that requested that DEQ perform four-factor analyses, or agreed to as part of consultation. Independence, White Bluff, FutureFuel, and Flint Creek were among the highest point source contributors to the total point source visibility surrogate value at Hercules Glades. White Bluff is under an enforceable commitment to cease coal-fired operations by the end of 2028, which should help to address Arkansas's share of emission reductions for Hercules Glades during Planning Period II. Independence is under an enforceable commitment to cease coal-fired operations, which will occur during Planning Period III and should help to address Arkansas's share of emission reductions for Hercules Glades. DEQ has included a control strategy for FutureFuel for Planning Period II that is anticipated to reduce its contribution to visibility impairment at Hercules Glades. Additional control measures included in Arkansas's long-term strategy, beyond the source-specific controls determined as a result of the reasonable progress evaluation described in this chapter, are described in Chapter VI and are also anticipated to reduce Arkansas's contribution to visibility impairment at federal Class I areas in other states.