ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R06–OAR–2015–0189; FRL–9986–67–Region 6]

Approval and Promulgation of Implementation Plans; Arkansas; Approval of Regional Haze State Implementation Plan Revision and Partial Withdrawal of Federal Implementation Plan

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: Pursuant to the Federal Clean Air Act (CAA or the Act), the Environmental Protection Agency (EPA) is proposing to approve a portion of the revision to the Arkansas State Implementation Plan (SIP) that addresses certain requirements of the CAA and the EPA's regional haze rules for the protection of visibility in mandatory Class I Federal areas (Class I areas) for the first implementation period. The EPA is proposing to approve the portions of the SIP revision addressing the best available retrofit technology (BART) requirements for sulfur dioxide (SO_2), particulate matter (PM) and nitrogen oxide (NO_X) for seven electric generating units (EGUs) in Arkansas. The EPA is also proposing to approve the determination that no additional controls at any Arkansas sources are necessary under reasonable progress; calculation of the revised reasonable progress goals (RPGs) for Arkansas' Class I areas; certain components of the long-term strategy for making reasonable progress; the clarification that both the 6A and 9A Boilers at the Georgia-Pacific Crossett Mill are BART-eligible; and the additional information and technical analysis in support of the determination that the Georgia-Pacific Crossett Mill 6A and 9A Boilers are not subject to BART. In conjunction with our proposed approval of portions of the SIP revision, we are proposing to withdraw the corresponding federal implementation plan (FIP) provisions established in a prior action to address regional haze requirements for Arkansas.

DATES: Written comments must be received on or before December 31, 2018.

ADDRESSES: Submit your comments, identified by Docket No. EPA–R06–OAR–2015–0189, at *http://www.regulations.gov* or via email to *R6AIR_ARHaze@epa.gov*. Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from *Regulations.gov*. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.* on the web, cloud, or other file sharing system). For additional submission methods, please contact Dayana Medina, *medina.dayana@epa.gov*. For the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *http://www2.epa.gov/dockets/commenting-epa-dockets*.

Docket: The index to the docket for this action is available electronically at *www.regulations.gov* and in hard copy at the EPA Region 6, 1445 Ross Avenue, Suite 700, Dallas, Texas. While all documents in the docket are listed in the index, some information may be publicly available only at the hard copy location (*e.g.,* copyrighted material), and some may not be publicly available at either location (*e.g.,* CBI).

FOR FURTHER INFORMATION CONTACT: Dayana Medina, 214–665–7241, *medina.dayana@epa.gov*. To inspect the hard copy materials, please schedule an appointment with Dayana Medina or Mr. Bill Deese at 214–665–7253.

SUPPLEMENTARY INFORMATION: Throughout this document wherever "we," "us," or "our" is used, we mean the EPA.

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I. Background

A. The Regional Haze Program

Regional haze is visibility impairment that is produced by a multitude of sources and activities that are located across a broad geographic area and emit fine particulates ($PM_{2.5}$) (*e.g.,* sulfates, nitrates, organic carbon (OC), elemental carbon (EC), and soil dust), and their precursors (*e.g.,* SO_2, NO_X, and in some cases, ammonia (NH_3) and volatile organic compounds (VOCs)). Fine particle precursors react in the atmosphere to form $PM_{2.5}$, which impairs visibility by scattering and absorbing light. This light scattering reduces the clarity, color and visible distance that one can see. Particulate matter can also cause serious health effects in humans (including premature death, heart attacks, irregular heartbeat, aggravated asthma, decreased lung function and increased respiratory symptoms) and contribute to environmental effects such as acid deposition and eutrophication.

Data from the existing visibility monitoring network, the ''Interagency Monitoring of Protected Visual Environments'' (IMPROVE) monitoring network, show that at the time the Regional Haze Rule was finalized in 1999, visibility impairment caused by air pollution occurred virtually all the time at most national parks and wilderness areas. The average visual range [1] in many Class I areas in the western U.S. was 62–93 miles, but in some Class I areas, these visual ranges may have been impacted by natural wildfire and dust episodes in addition to anthropogenic impacts. In most of the eastern Class I areas of the U.S., the average visual range was less than 19 miles.[2] CAA programs have reduced emissions of some haze-causing pollution, lessening some visibility impairment and resulting in partially improved average visual ranges.[3]

In section 169A of the 1977 Amendments to the CAA, Congress created a program for protecting visibility in the nation's national parks and wilderness areas. This section of the CAA establishes as a national goal the prevention of any future, and the remedying of any existing, man-made impairment of visibility in 156 national parks and wilderness areas designated as mandatory Class I Federal areas.[4] Congress added section 169B to the CAA in 1990 to address regional haze issues, and the EPA promulgated regulations addressing regional haze in 1999. The Regional Haze Rule [5] revised the existing visibility regulations to add provisions addressing regional haze impairment and established a comprehensive visibility protection program for Class I areas. The requirements for regional haze, found at 40 CFR 51.308 and 51.309, are included in our visibility protection regulations at 40 CFR 51.300–309. The requirement to submit a regional haze SIP revision at periodic intervals applies to all 50 states, the District of Columbia, and the Virgin Islands. States were required to submit the first implementation plan addressing regional haze visibility impairment no later than December 17, 2007.[6]

Section 169A of the CAA directs states to evaluate the use of retrofit controls at certain larger, often under-controlled, older stationary sources in order to address visibility impacts from these sources. Specifically, section 169A(b)(2)(A) of the CAA requires states to revise their SIPs to contain such measures as may be necessary to make reasonable progress toward the natural visibility goal, including a requirement that certain categories of existing major stationary sources [7] built between 1962 and 1977 procure, install, and operate BART controls. Larger ''fossil-fuel fired steam electric plants'' are one of these source categories. Under the Regional Haze Rule, states are directed to conduct BART determinations for ''BART-eligible'' sources that may be anticipated to cause or contribute to any visibility impairment in a Class I area. Sources that are reasonably anticipated to cause or contribute to any visibility impairment in a Class I area are determined to be subject-to-BART. For each source subject to BART, 40 CFR 51.308(e)(1)(ii)(A) requires that states (or EPA, in the case of a FIP) identify the level of control representing BART after considering the factors set out in CAA section 169A(g). The evaluation of BART for EGUs that are located at fossil-fuel fired power plants having a generating capacity in excess of 750 megawatts (MW) must follow the ''Guidelines for BART Determinations Under the Regional Haze Rule'' at appendix Y to 40 CFR part 51 (hereinafter referred to as the ''BART Guidelines''). Rather than requiring source-specific BART controls, states also have the flexibility to adopt an emissions trading program or other alternative program as long as the alternative provides for greater reasonable progress towards improving visibility than BART.

The vehicle for ensuring continuing progress towards achieving the natural visibility goal is the submission of a series of regional haze SIPs that contain long-term strategies to make reasonable progress towards natural visibility conditions. As part of this process, States also establish RPGs for every Class I area to provide assessments of the improvements in visibility anticipated to result from the long-term strategies. States have significant flexibility in establishing long-term strategies and RPGs,[8] but must determine whether additional control measures beyond BART and other ''on the books'' controls are needed for reasonable progress based on consideration of the following factors set out in section 169A of the CAA: (1) The costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources. States must demonstrate in their SIPs how these factors are considered when selecting measures for their long-term strategies and calculating the associated RPGs for each applicable Class I area. We commonly refer to this as the ''reasonable progress analysis'' or ''four factor analysis.''

B. Our Previous Actions on Arkansas Regional Haze

Arkansas submitted a SIP revision on September 9, 2008, to address the requirements of the first regional haze implementation period. On August 3, 2010, Arkansas submitted a SIP revision with mostly non-substantive revisions to Arkansas Pollution Control and Ecology Commission (APCEC) Regulation 19, Chapter 15.[9] On

[1] Visual range is the greatest distance, in kilometers or miles, at which a dark object can be discerned against the sky by a typical observer. Visual range is inversely proportional to light extinction (bext) by particles and gases and is calculated as: Visual Range = 3.91/bext (Bennett, M.G., The physical conditions controlling visibility through the atmosphere; Quarterly Journal of the Royal Meteorological Society, 1930, 56, 1–29). Light extinction has units of inverse distance (*i.e.,* Mm^{-1} or inverse Megameters [mega = 106]).

[2] 64 FR 35715 (July 1, 1999).

[3] An interactive ''story map'' depicting efforts and recent progress by EPA and states to improve visibility at national parks and wilderness areas may be visited at: *http://arcg.is/29tAbS3.*

[4] Areas designated as mandatory Class I Federal areas consist of National Parks exceeding 6,000 acres, wilderness areas and national memorial parks exceeding 5,000 acres, and all international parks that were in existence on August 7, 1977. 42 U.S.C. 7472(a). In accordance with section 169A of the CAA, EPA, in consultation with the Department of Interior, promulgated a list of 156 areas where visibility is identified as an important value. 44 FR 69122 (November 30, 1979). The extent of a mandatory Class I area includes subsequent changes in boundaries, such as park expansions. 42 U.S.C. 7472(a). Although states and tribes may designate as Class I additional areas which they consider to have visibility as an important value, the requirements of the visibility program set forth in section 169A of the CAA apply only to ''mandatory Class I Federal areas.'' Each mandatory Class I Federal area is the responsibility of a ''Federal Land Manager.'' 42 U.S.C. 7602(i). When we use the term ''Class I area'' in this action, we mean a ''mandatory Class I Federal area.''

[5] Here and elsewhere in this document, the term ''Regional Haze Rule,'' refers to the 1999 final rule (64 FR 35714), as amended in 2005 (70 FR 39156, July 6, 2005), 2006 (71 FR 60631, October 13, 2006), 2012 (77 FR 33656, June 7, 2012), and 2017 (82 FR 3078, January 10, 2017).

[6] See 40 CFR 51.308(b). EPA's regional haze regulations require subsequent updates to the regional haze SIPs. 40 CFR 51.308(f)–(i). The next update is due by July 31, 2021.

[7] See 42 U.S.C. 7491(g)(7) (listing the set of ''major stationary sources'' potentially subject-to-BART).

[8] *Guidance for Setting Reasonable Progress Goals under the Regional Haze Program,* June 1, 2007, memorandum from William L. Wehrum, Acting Assistant Administrator for Air and Radiation, to EPA Regional Administrators, EPA Regions 1–10 (pp. 4–2, 5–1).

[9] The September 9, 2008, SIP submittal included APCEC Regulation 19, Chapter 15, which is the state regulation that identified the BART-eligible and subject-to-BART sources in Arkansas and established BART emission limits for subject-to-

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September 27, 2011, the State submitted supplemental information to address the regional haze requirements. We are hereafter referring to these regional haze submittals collectively as the ''2008 Arkansas Regional Haze SIP.'' On March 12, 2012, we partially approved and partially disapproved the 2008 Arkansas Regional Haze SIP.[10] On September 27, 2016, we promulgated a FIP (the Arkansas Regional Haze FIP) addressing the disapproved portions of the 2008 Arkansas Regional Haze SIP.[11] Among other things, the FIP established SO_2, NO_X, and PM emission limits under the BART requirements for nine units at six facilities: AECC Bailey Plant Unit 1; AECC McClellan Plant Unit 1; SWEPCO Flint Creek Plant Boiler No. 1; Entergy Lake Catherine Plant Unit 4; Entergy White Bluff Plant Units 1 and 2; Entergy White Bluff Auxiliary Boiler; and the Domtar Ashdown Mill Power Boilers No. 1 and 2. The FIP also established SO_2 and NO_X emission limits under the reasonable progress requirements for Entergy Independence Units 1 and 2.

Following the issuance of the Arkansas Regional Haze FIP, the State of Arkansas and several industry parties filed petitions for reconsideration and an administrative stay of the final rule.[12] On April 14, 2017, we announced our decision to convene a proceeding to reconsider several elements of the FIP, as follows: Appropriate compliance dates for the NO_X emission limits for Flint Creek Boiler No. 1, White Bluff Units 1 and 2, and Independence Units 1 and 2; the low-load NO_X emission limits applicable to White Bluff Units 1 and 2 and Independence Units 1 and 2 during periods of operation at less than 50 percent of the unit's maximum heat input rating; the SO_2 emission limits for White Bluff Units 1 and 2; and the compliance dates for the SO_2 emission limits for Independence Units 1 and 2.[13]

EPA also published a notice in the **Federal Register** on April 25, 2017, administratively staying the effectiveness of the NO_X compliance dates in the FIP for the Flint Creek, White Bluff, and Independence units, as well as the compliance dates for the SO_2 emission limits for the White Bluff and Independence units for a period of 90 days.[14] On July 13, 2017, the EPA published a proposed rule to extend the NO_X compliance dates for Flint Creek Boiler No. 1, White Bluff Units 1 and 2, and Independence Units 1 and 2, by 21 months to January 27, 2020.[15] However, EPA did not take final action on the July 13, 2017, proposed rule because on July 12, 2017, Arkansas submitted a proposed SIP revision with a request for parallel processing, addressing the NO_X BART requirements for Bailey Unit 1, McClellan Unit 1, Flint Creek Boiler No. 1, Lake Catherine Unit 4, White Bluff Units 1 and 2, White Bluff Auxiliary Boiler, as well as the reasonable progress requirements with respect to NO_X (Arkansas Regional Haze NO_X SIP revision or Arkansas NO_X SIP revision). In a proposed rule published in the **Federal Register** on September 11, 2017, we proposed to approve the Arkansas Regional Haze NO_X SIP revision and to withdraw the corresponding parts of the Arkansas Regional Haze FIP.[16] On October 31, 2017, we received ADEQ's final Regional Haze NO_X SIP revision addressing NO_X BART for EGUs and the reasonable progress requirements with respect to NO_X for the first implementation period. On February 12, 2018, we took final action to approve the Arkansas Regional Haze NO_X SIP revision and to withdraw the corresponding parts of the FIP.[17]

II. Our Evaluation of Arkansas' SO_2 and PM Regional Haze SIP Revision

On August 8, 2018, Arkansas submitted a SIP revision (Arkansas Regional Haze SO_2 and PM SIP revision) addressing all remaining disapproved parts of the 2008 Regional Haze SIP, with the exception of the BART and associated long-term strategy requirements for the Domtar Ashdown Mill Power Boilers No. 1 and 2. The SIP revision also includes a discussion on Arkansas' interstate visibility transport requirements. We are proposing action on a portion of the August 8, 2018, Arkansas Regional Haze SO_2 and PM SIP revision in this **Federal Register** notice, and we are also proposing to withdraw the parts of the FIP corresponding to our proposed approvals. Since we are proposing to withdraw certain portions of the FIP, we are also proposing to redesignate the FIP by revising the numbering of certain paragraphs under section 40 CFR 52.173. Our proposed redesignation of the numbering of these paragraphs is non-substantive and does not mean we are reopening these parts for public comment in this proposed rulemaking. We intend to propose action on the portion of this SIP revision discussing the interstate visibility transport requirements for pollutants that affect visibility in Class I areas in nearby states in a future proposed rulemaking.

The Arkansas Regional Haze SO_2 and PM SIP revision submitted to us on August 8, 2018, addresses the majority of the remaining parts of the 2008 Regional Haze SIP that EPA disapproved on March 12, 2012.[18] Specifically, the August 8, 2018, SIP revision revises ADEQ's identification of BART-eligible sources by now identifying the 6A Boiler at the Georgia-Pacific Crossett Mill as BART-eligible; provides additional information and technical analysis in support of the determination that the Georgia-Pacific Crossett Mill 6A and 9A Boilers are not subject to BART;[19] prohibits the burning of fuel oil at Lake Catherine Unit 4 until SO_2 and PM BART determinations for the fuel oil firing scenario are approved into the SIP by EPA; and addresses the following BART requirements: SO_2 and PM BART for Bailey Unit 1 and McClellan Unit 1; SO_2 BART for Flint Creek Boiler No. 1; SO_2 BART for White Bluff Units 1 and 2; and SO_2, NO_X, and PM BART for the White Bluff Auxiliary Boiler. The SIP revision also addresses the reasonable progress requirements, arriving at the conclusion that no additional controls at Independence Units 1 and 2 or any other Arkansas sources are necessary under reasonable progress,[20] and establishes revised RPGs for Arkansas' two Class I areas, the Caney Creek Wilderness Area and the Upper Buffalo Wilderness Area. Finally, the SIP

BART sources. The August 3, 2010, SIP revision did not revise Arkansas' list of BART-eligible and subject-to-BART sources or revise any of the BART requirements for affected sources. Instead, it included mostly non-substantive revisions to the state regulation.

[10] 77 FR 14604.

[11] 81 FR 66332; *see also* 81 FR 68319 (October 4, 2016) (correction).

[12] See the docket associated with this proposed rulemaking for a copy of the petitions for reconsideration and administrative stay submitted by the State of Arkansas; Entergy Arkansas Inc., Entergy Mississippi Inc., and Entergy Power LLC (collectively ''Entergy''); AECC; and the Energy and Environmental Alliance of Arkansas (EEAA).

[13] Letter from E. Scott Pruitt, Administrator, EPA, to Nicholas Jacob Bronni and Jamie Leigh Ewing, Arkansas Attorney General's Office (April 14, 2017). A copy of this letter is included in the docket, *https://www.regulations.gov/document?D=EPA-R06-OAR-2015-0189-0240.*

[14] 82 FR 18994.

[15] 82 FR 32284.

[16] 82 FR 42627.

[17] 83 FR 5927 and 83 FR 5915 (February 12, 2018).

[18] 77 FR 14604.

[19] BART eligible sources that are reasonably anticipated to cause or contribute to any visibility impairment in a Class I area are determined to be subject-to-BART. In the 2008 Arkansas Regional Haze SIP, ADEQ used a contribution threshold of 0.5 dv for determining whether a source ''contributes'' to visibility impairment and is thus subject to BART.

[20] In a SIP revision submitted on October 31, 2017, Arkansas provided a reasonable progress analysis and reasonable progress determination with respect to NO_X, and we took final action to approve the analysis and determination in a final action published on February 12, 2018 (see 83 FR 5927). Thus, the August 8, 2018 SIP revision addresses reasonable progress requirements with respect to SO_2 and PM emissions.

revision revises the State's long-term strategy by including in the long-term strategy an SO_2 emission limit of 0.60 lb/MMBtu for Independence Units 1 and 2 based on the use of low sulfur coal, as well as each of the BART measures listed above. The August 8, 2018, SIP revision does not address BART for the Domtar Ashdown Mill Power Boilers No. 1 and 2 and relies on the Domtar BART emission limits from our FIP and the 2012 partially approved SIP for the associated long-term strategy requirements.

The August 8, 2018, SIP revision is the subject of this proposed action, in conjunction with our proposed withdrawal of the parts of the Arkansas Regional Haze FIP corresponding to our proposed approval. We are proposing to approve ADEQ's revised identification of the 6A Boiler at the Georgia-Pacific Crossett Mill as BART-eligible; the additional information and technical analysis presented in the SIP revision in support of the determination that the Georgia-Pacific Crossett Mill 6A and 9A Boilers are not subject to BART; and the state's BART decisions for the seven subject-to-BART units listed above. We are proposing to withdraw our prior approval of Arkansas' reliance on participation in the Cross-State Air Pollution Rule (CSAPR) for ozone season NO_X to satisfy the NO_X BART requirement for the White Bluff Auxiliary Boiler. The Arkansas Regional Haze NO_X SIP revision erroneously stated that the Auxiliary Boiler participates in CSAPR for ozone season NO_X and that the state was electing to rely on participation in that trading program to satisfy the Auxiliary Boiler's NO_X BART requirements, and we erroneously approved this determination in a final action published in the **Federal Register** on February 12, 2018.[21] We are proposing to withdraw our approval of that determination for the Auxiliary Boiler and to replace it with our proposed approval of a source specific NO_X BART emission limit contained in the Arkansas Regional Haze SIP Revision before us.

We are also proposing to approve Arkansas' reasonable progress determinations for Independence Units 1 and 2 and all other sources in Arkansas, and to approve the revised RPGs contained in the August 8, 2018, SIP revision. We are further proposing to find that, based on the state's currently approved SIP and the analyses and determinations we are proposing to approve in this action, the state's reasonable progress obligations for the first implementation period have been satisfied. At this time, the majority of the BART requirements for the Domtar Ashdown Mill are satisfied by a FIP.[22] The SIP revision explains that, based upon the BART determinations and analysis in that FIP, nothing further is currently needed for reasonable progress at the Domtar Ashdown Mill. EPA agrees. If the State chooses to submit a further SIP revision to address BART requirements for Domtar Power Boilers No. 1 and No. 2 that are currently satisfied by the FIP, we will evaluate that SIP submittal, including as well as any conclusions ADEQ draws about the adequacy of such SIP-based measures for reasonable progress. We will also, at that time, evaluate any changes in the measures for the Domtar Ashdown Mill relative to those currently in the FIP to determine whether the calculation of the reasonable progress goals for the first implementation period continue to be sufficient.

Finally, we are proposing to approve the components of the long-term strategy addressed by the August 8, 2018, SIP revision and to find that Arkansas' long-term strategy for reasonable progress with respect to all sources other than Domtar is approved. The long-term strategy is the compilation of all control measures a state will use during the implementation period of the specific SIP submittal to make reasonable progress towards the goal of natural visibility conditions, including emission limitations corresponding to BART determinations. If the proposed approvals of the BART measures and the emission limitations for the Independence facility addressed in this action are finalized, those measures will also be integrated into the State's long-term strategy. Because the August 8, 2018, SIP revision does not address the BART requirements for Domtar, that component of the long-term strategy will remain satisfied by the FIP unless and until EPA has received and approved a SIP revision containing the required analyses and determinations for this facility.

We are also proposing to withdraw the majority of the Arkansas Regional Haze FIP we promulgated on September 27, 2016. Upon finalization of this proposed rulemaking, the majority of remaining FIP provisions would be replaced by the corresponding revisions to the SIP that we are proposing to approve in this proposed rulemaking. Specifically, we are proposing to withdraw the following components of the FIP: The SO_2 and PM BART emission limits for Bailey Unit 1; the SO_2 and PM BART emission limits for McClellan Unit 1; the SO_2 BART emission limit for Flint Creek Boiler No. 1; the SO_2 BART emission limit for White Bluff Units 1 and 2; the SO_2 and PM BART emission limits for the White Bluff Auxiliary Boiler; the prohibition on burning fuel oil at Lake Catherine Unit 4; and the SO_2 emission limits for Independence Units 1 and 2 under the reasonable progress provisions. Since we are proposing to withdraw certain portions of the FIP, we are also proposing to redesignate the FIP by revising the numbering of certain paragraphs under section 40 CFR 52.173. Our proposed redesignation of the numbering of these paragraphs is non-substantive and does not mean we are reopening these parts for public comment in this proposed rulemaking.

The SIP revision also includes a discussion on interstate visibility transport. Specifically, the SIP revision discusses the impacts of Arkansas sources on Missouri's Class I areas, as well as the most recent IMPROVE monitoring data for Missouri's Class I areas. The SIP revision concludes that Missouri is on track to achieve its visibility goals, that the visibility progress observed indicates that sources in Arkansas are not interfering with the achievement of Missouri's RPGs for the Hercules-Glades Wilderness Area and Mingo Wilderness Area, and that no additional controls on sources within Arkansas are necessary to ensure that other states' visibility goals for their Class I areas are met. We are deferring proposing action on the interstate visibility transport portion of the SIP revision until a future proposed rulemaking.

A. Identification of BART-Eligible and Subject-to-BART Sources

States are required to identify all the BART-eligible sources within their boundaries by utilizing the three eligibility criteria in the BART Guidelines[23] and the Regional Haze Rule[24]: (1) One or more emission units at the facility fit within one of the 26 categories listed in the BART Guidelines; (2) the emission unit(s) began operation on or after August 6, 1962, and the unit was in existence on August 6, 1977; and (3) the potential emissions of any visibility impairing pollutant from subject units are 250 tons or more per year. Sources that meet

[21] 83 FR 5927.

[22] We note that the PM determination for Domtar Ashdown Mill Power Boiler No. 1 in the 2008 SIP was approved in our 2012 rulemaking. (77 FR 14604, March 12, 2012).

[23] 70 FR 39158.

[24] 40 CFR 51.301.

these three criteria are considered BART-eligible. Once a list of the BART-eligible sources within a state has been compiled, states must determine whether to make BART determinations for all of them or whether some may not reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area and may thus not be subject to further BART analysis or requirements. The BART Guidelines present several options that rely on modeling and/or emissions analyses to determine if a source may reasonably be anticipated to cause or contribute to visibility impairment in a Class I area. A source that may not be reasonably anticipated to cause or contribute to any visibility impairment in any Class I area is not ''subject to BART,'' and for such sources, a state need not make a BART determination.

In our March 12, 2012, final action on the 2008 Arkansas Regional Haze SIP, we approved Arkansas' identification of BART-eligible sources with the exception of the Georgia-Pacific Crossett Mill 6A Boiler.[25] We also approved Arkansas' determination of which sources are subject to BART, with the exception of its determination that the Georgia-Pacific Crossett Mill 6A and 9A Boilers are not subject to BART. In that final action, we determined that the 2008 Arkansas Regional Haze SIP did not include sufficient documentation to demonstrate that the 6A Boiler is not BART-eligible and did not contain sufficient documentation to demonstrate that the 6A and 9A Boilers are not subject to BART. In the Arkansas Regional Haze FIP, we made the determination that the 6A Boiler is BART-eligible. We also noted that we continued to agree with the state's previous determination from the 2008 Arkansas Regional Haze SIP that the 9A Boiler is BART-eligible. Based on additional information and a technical analysis provided to the EPA by Georgia-Pacific, EPA determined that the 6A and 9A Boilers are not subject to BART. In the August 8, 2018, Arkansas Regional Haze SO_2 and PM SIP revision, Arkansas has made determinations consistent with our findings in the FIP. Specifically, Arkansas made a revision to its identification of BART-eligible sources,[26] now identifying the 6A Boiler at the Georgia-Pacific Crossett Mill as BART-eligible. In the 2008 Arkansas Regional Haze SIP, the state had already identified the 9A Boiler at the Georgia-Pacific Crossett Mill as BART-eligible; in the August 8, 2018, SIP revision, the state made no changes to the identification of the 9A Boiler as BART-eligible. In addition, Arkansas included in the SIP revision a copy of the technical analysis and other information that was provided by Georgia-Pacific to EPA, which we previously included in the record for the Arkansas Regional Haze FIP in support of our determination that the 6A and 9A Boilers are not subject to BART.[27] As Arkansas explains in the SIP revision, Georgia-Pacific provided information regarding revisions to emission limits included in the facility's permit and additional dispersion modeling conducted in 2011 using those revised limits. The results of this 2011 BART screening modeling demonstrated that the maximum impact of the Georgia-Pacific Crossett Mill boilers on any Class I area was less than the 0.5 dv threshold used by ADEQ to determine whether a BART-eligible source should be considered subject to BART. Because the 2011 BART screening modeling was based on permit limits from a permit revision issued in 2012 rather than on maximum 24-hour emission rates from the 2001–2003 baseline period, Georgia-Pacific also provided further information regarding fuel usage during the 2001–2003 baseline and performed calculations using AP–42, Compilation of Air Pollutant Emission Factors, to estimate the 24-hour emission rates for SO_2, NO_X, and PM_{10} for the 6A and 9A Boilers for each day during the baseline years. Georgia Pacific then identified the maximum 24-hour emission rates for each pollutant for the two boilers during the 2001–2003 baseline period. A comparison of the estimated maximum 24-hour emission rates with the emission rates modeled in Georgia-Pacific's 2011 BART screening modeling demonstrates that the maximum 24-hour emission rates from the 2001–2003 baseline were lower than the rates modeled in the 2011 BART screening modeling and lower than the boilers' permit limits. Based upon the additional information provided by Georgia-Pacific, ADEQ concluded that the 6A and 9A Boilers are not subject to BART.[28] Thus, ADEQ revised its identification of BART-eligible sources by identifying the Georgia-Pacific Mill 6A Boiler as BART-eligible. Since ADEQ previously determined in the 2008 Regional Haze SIP that the 9A Boiler is BART-eligible, it made no change to that previous determination. ADEQ did not make changes to its list of subject-to-BART sources, but did include in the SIP revision the additional information and technical analysis from Georgia-Pacific to support and document the determination that the 6A and 9A boilers are not subject to BART.

We are proposing to find that the analysis and documentation provided by Georgia-Pacific and included in the Arkansas Regional Haze SO_2 and PM SIP revision appropriately and sufficiently demonstrate that the 6A and 9A Boilers are not subject to BART. We are proposing to approve ADEQ's revised determination that the 6A Boiler is BART-eligible and concur that the 6A and 9A Boilers are not subject to BART.

B. Arkansas' Five-Factor Analyses for SO_2 and PM BART

In determining BART, the state must consider the five statutory factors in section 169A of the CAA: (1) The costs of compliance; (2) the energy and nonair quality environmental impacts of compliance; (3) any existing pollution control technology in use at the source; (4) the remaining useful life of the source; and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.[29] All units that are subject to BART must undergo a BART analysis. The BART Guidelines break the analysis down into five steps:[30]

STEP 1—Identify All Available Retrofit Control Technologies,

STEP 2—Eliminate Technically Infeasible Options,

STEP 3—Evaluate Control Effectiveness of Remaining Control Technologies,

STEP 4—Evaluate Impacts and Document the Results, and

STEP 5—Evaluate Visibility Impacts.

As mentioned previously, EPA partially approved and partially disapproved the 2008 Arkansas Regional Haze SIP revision in a final action published on March 12, 2012.[31] Following our 2012 partial disapproval of the 2008 Arkansas Regional Haze SIP, ADEQ began the process of generating additional technical information and analyses from the companies whose BART determinations we disapproved. These analyses and technical

[25] 80 FR 18947.

[26] See Arkansas Regional Haze SO_2 and PM SIP revision, Table 1, page 8 and 9.

[27] See the documentation provided by Georgia Pacific to EPA that was previously included in the record for the Arkansas Regional Haze FIP. This documentation is included in the docket at the following location: *https://www.regulations.gov/searchResults?rpp=50&so=ASC&sb=docId&po=0&dktid=EPA-R06-OAR-2015-0189.*

[28] ADEQ provides documentation in support of the determination that the Georgia-Pacific Crossett Mill 6A and 9A Boilers are not subject to BART in Appendix A to the Arkansas Regional Haze SO_2 and PM SIP revision.

[29] See also 40 CFR 51.308(e)(1)(ii)(A).

[30] 70 FR 39103, 39164 (July 6, 2005) [40 CFR 51, App. Y].

[31] 77 FR 14604.

information were provided to EPA and were the basis for our evaluation of BART for subject-to-BART facilities in the FIP. In turn, ADEQ relied on those same analyses and technical information in the state's evaluation of BART for subject-to-BART sources in the Arkansas Regional Haze SO_2 and PM SIP revision, with the exception of White Bluff Units 1 and 2, for which updated technical information has been provided by Entergy and is included in the SIP revision. In evaluating the Arkansas Regional Haze SO_2 and PM SIP revision, we reviewed each BART analysis for SO_2 and PM for each subject-to-BART source and other relevant information provided in the SIP revision.

As noted above, we approved certain parts of the 2008 Arkansas Regional Haze SIP in 2012.[32] The parts that we approved in 2012 included PM BART for Flint Creek Boiler No. 1; PM BART for White Bluff Units 1 and 2; SO_2 and PM BART for the natural gas firing scenario for Lake Catherine Unit 4; and PM BART for Domtar Power Boiler No. 1. We also published a final action on February 12, 2018, in which we approved a SIP revision submitted by ADEQ on October 31, 2017, to address the regional haze requirements for NO_X for EGUs in Arkansas (''Arkansas Regional Haze NO_X SIP Revision'').[33] That final action included approval of Arkansas' NO_X BART determinations for Bailey Unit 1; McClellan Unit 1; Flint Creek Boiler No. 1; Lake Catherine Unit 4 (for both the natural gas firing and fuel oil firing scenarios); White Bluff Units 1 and 2; and the White Bluff Auxiliary Boiler; and removed the corresponding portions of the Arkansas Regional Haze FIP. Thus, the only BART requirements currently addressed under the Arkansas Regional Haze FIP are the SO_2 and PM BART requirements for Bailey Unit 1; the SO_2 and PM BART requirements for McClellan Unit 1; the SO_2 BART requirements for Flint Creek Boiler No. 1; the prohibition on burning fuel oil at Lake Catherine Unit 4 until SO_2 and PM BART determinations for the fuel oil firing scenario are approved into the SIP by EPA; the SO_2 BART requirements for White Bluff Units 1 and 2; the SO_2 and PM BART requirements for the White Bluff Auxiliary Boiler; the SO_2 and NO_X BART requirements for the Domtar Ashdown Mill Power Boiler No. 1; and the SO_2, NO_X, and PM BART requirements for the Domtar Ashdown Mill Power Boiler No. 2. The Arkansas Regional Haze SO_2 and PM SIP revision addresses all these BART requirements currently covered under the FIP, with the exception of the requirements for the Domtar Ashdown Mill Power Boilers No. 1 and 2. As noted above, in the Arkansas Regional Haze NO_X SIP revision, ADEQ erroneously stated that the Auxiliary Boiler participated in CSAPR for ozone season NO_X and the state decided to rely on participation in that trading program to satisfy the Auxiliary Boiler's NO_X BART requirement. In a final action published in the **Federal Register** on February 12, 2018, we took final action to approve this SIP revision, including reliance on CSAPR for ozone season NO_X to satisfy the Auxiliary Boiler's NO_X BART requirement.[34] Since the White Bluff Auxiliary Boiler does not participate in CSAPR for ozone season NO_X, we are proposing to withdraw our prior approval of the NO_X BART determination for the Auxiliary Boiler and to replace it with our proposed approval of a source specific NO_X BART emission limit contained in the August 8, 2018, Arkansas Regional Haze SIP revision. We discuss this in greater detail in section II.B.5.b. of this proposed action.

1. AECC Bailey Unit 1

The AECC Bailey Unit 1 has a wall-fired boiler, a gross output of 122 MW, and a maximum heat input rate of 1,350 million British thermal units per hour (MMBtu/hr). The unit is currently permitted to burn pipeline quality natural gas and fuel oil. The fuel oil burned is currently subject to a sulfur content limit of 2.3% by weight. AECC produced BART analyses dated March 2014 for Bailey Unit 1, which were evaluated by EPA and largely formed the basis for EPA's SO_2 and PM BART evaluations in the FIP.[35] The same BART analyses[36] have now been adopted and incorporated by ADEQ into the Arkansas Regional Haze SO_2 and PM BART SIP revision to address the SO_2 and PM BART requirements for Bailey Unit 1.

a. SO_2 BART Analysis and Determination

In assessing SO_2 BART, ADEQ explained that AECC considered the five BART factors. In assessing feasible control technologies and their effectiveness, AECC considered flue gas desulfurization (FGD) systems and fuel switching during fuel oil burning. Due to the intrinsically low sulfur content of natural gas, no control technologies were evaluated for natural gas burning scenarios. As such, the BART analysis focused on fuel oil firing as the base case. For fuel oil firing, fuel switching was determined to be the only technically feasible control option, and thus AECC did not further consider FGD for SO_2 BART. The baseline fuel AECC assumed in the BART analysis is No. 6 fuel oil with 1.81% sulfur content by weight, which is based on the average sulfur content of the fuel oil from the most recent shipment received by the facility in December 2006. ADEQ explained that AECC evaluated switching to the following fuel types: 1% sulfur No. 6 fuel oil, corresponding to an estimated 45% control efficiency; 0.5% sulfur No. 6 fuel oil, corresponding to 72% control efficiency; and 0.05% sulfur diesel, corresponding to 97% control efficiency.[37]

In considering the costs of compliance for fuel switching, AECC concluded that the fuel switching options evaluated would not require capital investments in equipment, but instead the annual costs would be based upon operation and maintenance costs associated with the different fuel types. AECC estimated that the cost-effectiveness of switching Bailey Unit 1 to No. 6 fuel oil with 1% and 0.5% sulfur content by weight is $1,198/ton and $2,559/ton, respectively. Switching to diesel, which has 0.05% sulfur content, is estimated to cost $5,382/ton. ADEQ stated that the cost in dollars per ton for diesel is out of the range of what is typically considered cost-effective, while the cost of both 1% and 0.5% sulfur No. 6 fuel oil is estimated to be within the range of what is typically considered cost-effective.

ADEQ stated that AECC's evaluation did not identify any energy or non-air quality environmental impacts associated with switching to 1% sulfur No. 6 fuel oil, 0.5% sulfur No. 6 fuel oil, or diesel. In assessing the remaining useful life of Bailey Unit 1, AECC concluded that this factor does not impact the annualized costs of the evaluated control options since fuel switching is not expected to require any significant capital costs in this case.

[32] 77 FR 14604.

[33] 83 FR 5927.

[34] 83 FR 5927.

[35] 80 FR 18950.

[36] ''BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations,'' dated March 2014, Version 4, prepared by Trinity Consultants Inc. in conjunction with Arkansas Electric Cooperative Corporation,'' which can be found in Appendix B to the Arkansas Regional Haze SO_2 and PM BART SIP Revision.

[37] We also note that AECC evaluated switching to natural gas as an available SO_2 control option in its SO_2 BART analysis, but the evaluation of this control option was not discussed by ADEQ in the SIP revision. We discuss this issue in greater detail below when we present our evaluation of the state's BART determination.

In assessing visibility impacts, the state's submittal included CALPUFF modeling evaluating the visibility benefits of switching from the baseline fuel oil (assuming 100% use of fuel oil) to the various fuel switching options. We summarize the results of that modeling in Table 1.

TABLE 1—ANTICIPATED VISIBILITY BENEFIT DUE TO FUEL SWITCHING AT AECC BAILEY UNIT 1

[CALPUFF, 98th percentile]

Class I area	Baseline visibility impact (dv)	Visibility benefit of controls over baseline (dv)		
		No. 6 fuel oil—1% sulfur	No. 6 fuel oil—0.5% sulfur	Diesel—0.05% sulfur
Caney Creek	0.330	0.137	0.188	0.246
Upper Buffalo	0.348	0.154	0.221	0.279
Hercules-Glades	0.368	0.162	0.233	0.299
Mingo	0.379	0.173	0.209	0.284

Switching to 1% sulfur No. 6 fuel oil is anticipated to achieve visibility benefits of approximately 0.137 dv at Caney Creek, 0.154 dv at Upper Buffalo, 0.162 dv at Hercules-Glades, and 0.173 dv at Mingo over baseline visibility conditions. Switching to 0.5% sulfur No. 6 fuel oil is anticipated to achieve visibility benefits of approximately 0.188 dv at Caney Creek, 0.221 dv at Upper Buffalo, 0.233 dv at Hercules-Glades, and 0.209 dv at Mingo over the baseline. The visibility benefits of switching to diesel are anticipated to be even greater, with benefits of approximately 0.246 dv at Caney Creek, 0.279 dv at Upper Buffalo, 0.299 dv at Hercules-Glades, and 0.284 dv at Mingo over the baseline.

Taking into consideration the cost-effectiveness and the anticipated visibility improvement of the fuel switching options, ADEQ concurred with AECC's recommendation that SO_2 BART for AECC Bailey Unit 1 be determined to be the use of fuel with a sulfur content by weight of 0.5% or less.

We note that switching to diesel would result in additional reductions in SO_2 emissions, but the additional costs per ton for doing so would be high in comparison to the additional visibility benefits. We also note that AECC evaluated switching to natural gas as an available SO_2 control option in its SO_2 BART analysis,[38] but the evaluation of this control option in the SO_2 BART analysis was not discussed by ADEQ in the SIP revision. In its analysis, AECC explained that switching to natural gas may have an adverse energy impact during periods of natural gas curtailment and that the ability to burn both fuel oil and natural gas was important for the facility to maintain electrical reliability.[39] Therefore, AECC did not recommend switching to natural gas and instead recommended switching to fuels with 0.5% sulfur content to be SO_2 BART for Bailey Unit 1.[40] In the Arkansas Regional Haze FIP, we agreed with AECC's recommendation, and explained that the BART Guidelines provide that it is not our intent to direct subject-to-BART sources to switch fuel forms, such as from coal or fuel oil to natural gas (40 CFR part 51, Appendix Y, section IV.D.1).[41] We noted that since natural gas has a sulfur content by weight that is well below 0.5%, the facility may elect to use this type of fuel to comply with BART, but we did not require a switch to natural gas for SO_2 BART in the FIP.[42] Therefore, we do not find that ADEQ's lack of consideration of switching to natural gas as an SO_2 control option in the SO_2 BART analysis for Bailey Unit 1 changes the result of the BART analysis in this instance. We are proposing to approve the state's determination that SO_2 BART for AECC Bailey Unit 1 is the use of fuel with a sulfur content by weight of 0.5% or less. We are also proposing to approve the state's determination that Bailey Unit 1 must comply with this BART requirement no later than October 27, 2021, and that as of the effective date of the Administrative Order, which is August 7, 2018, the source shall not purchase fuel that does not meet the sulfur limit requirement for combustion at Bailey Unit 1. These BART requirements have now been made enforceable by the state through an Administrative Order that has been adopted and incorporated in the SIP revision. The Administrative Order for AECC Bailey Unit 1 includes not only the requirement to limit the sulfur content of the fuel burned, but also requirements for the source to sample and analyze each shipment of fuel to determine the sulfur content by weight and maintain records pertaining to the sampling of each fuel shipment to assess compliance with the BART requirements.[43] We are proposing to approve the state's Administrative Order, including the compliance determination requirements contained in the Administrative Order, into the SIP. The state's SO_2 BART emission limit and compliance date for Bailey Unit 1 are consistent with the BART decision EPA previously made in the FIP we promulgated on September 27, 2016.[44] We are concurrently proposing to withdraw the FIP's SO_2 BART requirements for Bailey Unit 1, as they would be replaced by our approval of the state's SO_2 BART decision.

b. PM BART Analysis and Determination

PM emissions are inherently low when burning natural gas, but are higher when burning fuel oil. Bailey Unit 1 does not currently have pollution control equipment for PM emissions. In assessing PM BART for Bailey Unit 1, ADEQ explained that AECC considered the five BART factors. In assessing feasible control technologies and their

[38] See "BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations, dated March 2014, Version 4, prepared by Trinity Consultants Inc. in conjunction with Arkansas Electric Cooperative Corporation," pages 5–1 to 5–14. This BART analysis has been adopted and incorporated by ADEQ into the SIP revision (see Appendix B to the Arkansas Regional Haze SO_2 and PM BART SIP revision).

[39] See "BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations, dated March 2014, Version 4, prepared by Trinity Consultants Inc. in conjunction with Arkansas Electric Cooperative Corporation," pages 5–2, 5–10, and 5–14.

[40] *Id.*

[41] 80 FR 18952 and 81 FR at 66339.

[42] *Id.*

[43] The Administrative Order can be found in the Arkansas Regional Haze SO_2 and PM BART SIP Revision.

[44] The Arkansas Regional Haze FIP requires Bailey Unit 1 to only use fuel with a sulfur content limit of 0.5% by weight, with a compliance date of October 27, 2021. Additionally, the FIP prohibits the owner or operator of the unit from purchasing fuel for combustion at the unit that does not meet the sulfur content limit; the compliance date for this requirement is October 27, 2016. See 81 FR 66335, 66415–16.

effectiveness, AECC considered the following control technologies for PM BART: Dry electrostatic precipitator (ESP), wet ESP, fabric filter, wet scrubber, cyclone (*i.e.,* mechanical collector), and fuel switching. AECC's evaluation noted that the particulate matter from oil-fired boilers tends to be sticky and small, affecting the collection efficiency of dry ESPs and fabric filters. Dry ESPs operate by placing a charge on the particles through a series of electrodes, and then capturing the charged particles on collection plates, while fabric filters work by filtering the PM in the flue gas through filter bags. The collected particles are periodically removed from the filter bag through a pulse jet or reverse flow mechanism. Because of the sticky nature of particles from oil-fired boilers, AECC considered dry ESPs and fabric filters to be technically infeasible for use at Bailey Unit 1. AECC found wet ESPs, wet scrubbers, cyclones, and fuel switching to be technically feasible PM control options.

Residual fuel, such as the baseline No. 6 fuel oil burned at Bailey Unit 1, has inherent ash that contributes to emissions of filterable PM. Reductions in filterable PM emissions are directly related to the sulfur content of the fuel.[45] Therefore, switching to No. 6 fuel oil with a lower sulfur content is expected to result in lower filterable PM emissions. Also, ash content is much lower in a distillate fuel such as diesel and essentially zero in natural gas. The fuel switching options considered by AECC in the PM BART analysis are No. 6 fuel oil with 1% sulfur content by weight, No. 6 fuel oil with 0.5% sulfur content by weight, natural gas, and diesel. AECC estimated that switching to a lower sulfur fuel has a PM control efficiency ranging from approximately 44%–99%, depending on the fuel type. The estimated PM control efficiency of each control option is summarized in Table 2.

TABLE 2—PM CONTROL EFFICIENCY OF BART CONTROL OPTIONS FOR AECC BAILEY UNIT 1

PM control option	Wet scrubber	Cyclone	Wet ESP	Fuel switching			
				No. 6 fuel oil—1% S	No. 6 fuel oil—0.5% S	Natural gas	Diesel
PM Control Efficiency (%)	55.0	85.0	90.0	65.7	89.3	99.0	99.5

In considering the costs of the PM control options, AECC noted that add-on controls such as a wet scrubber, cyclone, and wet ESP involve capital costs for new equipment, which AECC annualized over a 15-year period in the analysis. Based on this analysis, AECC determined that the estimated cost-effectiveness of the add-on control options are as follows: $3,558,286/ton for a wet scrubber; $54,570/ton for a cyclone; and $981,583/ton for a wet ESP. AECC determined that the estimated cost-effectiveness of the fuel switching options are as follows: $27,528/ton for No. 6 fuel oil with 1% sulfur content; $22,386/ton for No. 6 fuel oil with 0.5% sulfur content; $25,004/ton for diesel; and $2,327/ton for natural gas. AECC noted that it does not consider any of the PM control options to be cost-effective.

ADEQ explained that AECC's PM BART evaluation did not discuss any energy or non-air quality environmental impacts associated with fuel switching. AECC did identify certain energy and non-air quality environmental impacts associated with wet ESPs and wet scrubbers. These impacts, which are factored in the cost of compliance, include increased energy usage for operation of the control equipment, the generation of wastewater streams that must be treated on-site or sent to a waste water treatment plant, and the generation of a filter cake that would likely require land-filling. In assessing the remaining useful life of Bailey Unit 1, AECC concluded that this factor does not impact the annualized costs of the evaluated control options since the remaining useful life of Bailey Unit 1 is at least as long as the capital cost recovery period of 15 years.

In assessing visibility impacts, the state's submittal included CALPUFF modeling evaluating the visibility benefits of switching from the baseline fuel oil (assuming 100% use of fuel oil) to the various fuel switching options. We summarize the results of that modeling in Table 3.

TABLE 3—ANTICIPATED VISIBILITY BENEFIT OF PM CONTROLS AT AECC BAILEY UNIT 1

[CALPUFF, 98th percentile]

Class I area	Baseline visibility impact (dv)	Visibility benefit of controls over baseline (dv)[46]						
		Wet scrubber	Cyclone	Wet ESP	No. 6 fuel oil—1% sulfur	No. 6 fuel oil—0.5% sulfur	Diesel—0.05% sulfur	Natural gas
Caney Creek	0.330	0.002	0.002	0.003	0.137	0.188	0.246	0.247
Upper Buffalo	0.347	0.002	0.002	0.004	0.154	0.221	0.279	0.276
Hercules-Glades	0.367	0.007	0.006	0.011	0.162	0.233	0.299	0.295
Mingo	0.378	0.004	0.004	0.007	0.173	0.209	0.284	0.277

The anticipated visibility benefits of add-on controls (*i.e.,* wet scrubber, cyclone, and wet ESP) are anticipated to be very small, ranging from 0.002 to 0.011 dv at each affected Class I area. As discussed above, fuel switching to lower

[45] See ''AP–42, Compilation of Air Pollutant Emission Factors,'' section 1.3.3.1, and Table 1.3–1, available at *http://www.epa.gov/ttnchie1/ap42/.*

[46] The modeled visibility improvement of the fuel switching options reflects both SO_2 and PM emissions reductions since reductions in filterable PM are directly related to the sulfur content of the fuel.

sulfur fuels is expected to result in both lower filterable PM emissions and lower SO_2 emissions. Switching to 1% sulfur No. 6 fuel oil is anticipated to achieve visibility benefits of approximately 0.137 dv at Caney Creek, 0.154 dv at Upper Buffalo, 0.162 dv at Hercules-Glades, and 0.173 dv at Mingo over baseline visibility conditions. Switching to 0.5% sulfur No. 6 fuel oil is anticipated to achieve visibility benefits of approximately 0.188 dv at Caney Creek, 0.221 dv at Upper Buffalo, 0.233 dv at Hercules-Glades, and 0.209 dv at Mingo over the baseline. The visibility benefits of switching to diesel are anticipated to be even greater, with benefits of approximately 0.246 dv at Caney Creek, 0.279 dv at Upper Buffalo, 0.299 dv at Hercules-Glades, and 0.284 dv at Mingo over the baseline. The visibility benefits of switching to natural gas are anticipated to be only slightly more than switching to diesel. The modeled visibility improvement of switching to lower sulfur fuels reflects benefits of both SO_2 and PM emissions reductions since reductions in filterable PM are directly related to the sulfur content of the fuel. We do note that the majority of the baseline visibility impact at each Class I area when burning the baseline fuel oil is due to SO_2 emissions that form sulfate PM, while direct PM_{10} emissions contribute only a small portion of the baseline visibility impacts at each Class I area.[47] Accordingly, the majority of the visibility improvement associated with switching to lower sulfur fuels, as shown in Table 3, can reasonably be expected to be the result of a reduction in SO_2 emissions rather than PM emissions.

Taking into consideration the cost-effectiveness and the anticipated visibility improvement of the PM control options considered, ADEQ concluded that add-on controls are not cost-effective, with AECC estimating the cost of these controls to be approximately $55,000/ton and greater. ADEQ concluded that the cost of switching to lower sulfur fuels is also not a cost-effective method for reducing PM emissions. However, ADEQ noted that the SO_2 BART determination for Bailey Unit 1, which is the use of fuel that has 0.5% or less sulfur content by weight, would also result in PM emissions reductions. ADEQ therefore arrived at the determination that PM BART for Bailey Unit 1 is no additional control beyond switching to fuel with 0.5% or less sulfur content, consistent with the SO_2 BART decision for the unit.

We do not agree with the use of a 15-year capital cost recovery period for calculating the average cost-effectiveness of a wet ESP, wet scrubber, and cyclone. Per the EPA Control Cost Manual, facilities are to rely on a 30-year capital cost recovery period for calculating the average cost-effectiveness of a wet ESP, wet scrubber, or cyclone barring a technical rationale to deviate from the 30-year capital cost recovery period. AECC Bailey Generating Station did not provide a technical rationale to deviate from the assumed 30-year capital cost recovery period. In addition, we are not aware of any enforceable shutdown date for the AECC Bailey Generating Station, nor did AECC's evaluation or ADEQ's SIP revision indicate any future planned shutdown or provide any reason for adopting a 15-year equipment life for the controls under consideration. Therefore, we believe that assuming a 30-year equipment life rather than a 15-year equipment life would be more appropriate for these control technologies.[48] Extending the amortization period from 15 to 30 years has the effect of decreasing the total annual cost of each control option, thereby improving the average cost-effectiveness value of controls (*i.e.,* lower dollars per ton removed). As discussed above, the cost of add-on PM control equipment at Bailey Unit 1, assuming a 15-year remaining useful life, ranges from $54,570/ton of PM removed for a cyclone to $3,558,286/ton of PM removed for a wet scrubber. Even though adjusting the costs of the add-on controls based on a 30-year remaining useful life as opposed to a 15-year remaining useful life would decrease the $/ton costs, we anticipate that the costs in $/ton would still be considerable and well outside of the range that has generally been considered to be cost-effective for BART. Therefore, we believe that add-on PM controls would still not be justified in light of the considerable costs and the minimal visibility benefits, which would range from 0.002 to 0.011 at each Class I area (see Table 3 above). Therefore, we are proposing to agree with ADEQ's determination that PM add-on controls are not PM BART for Bailey Unit 1.

We also disagree with the total annual cost and cost-effectiveness values for fuel switching presented in AECC's PM BART analysis[49] and in the SIP revision. In AECC's SO_2 BART cost analysis for the same unit, the company considered the same fuel switching options, yet the total annual cost numbers presented in the PM cost analysis are significantly greater than those presented in the SO_2 cost analysis.[50] This appears to be because in the SO_2 cost analysis, AECC calculated the differential cost of fuel switching (*i.e.,* the difference in cost between the baseline fuel and the fuel switching options), whereas the absolute cost of the fuel switching options was calculated in the PM cost analysis. We believe that AECC and ADEQ should have considered the differential cost of fuel switching as opposed to the absolute cost of fuel for each of the fuel switching options in the PM BART analysis, as was done in the SO_2 BART analysis. Thus, we believe that the correct cost effectiveness values that ADEQ should have considered in the PM BART analysis are those presented in Table 5–9 of AECC's SO_2 BART analysis,[51] which shows that the costs of switching to fuel oil with a sulfur content of 1% or 0.5% are within the range that have generally been considered to be cost-effective for BART. Although switching to diesel would result in additional reductions in PM emissions, we believe that the additional cost per ton for switching to diesel would be high in comparison to the additional visibility benefits.[52] We

[47] See Table 4–3 BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO BAILEY, UNIT 1 (2001–2003)—FUEL OIL, ''BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations,'' dated March 2014, Version 4, prepared by Trinity Consultants Inc. in conjunction with Arkansas Electric Cooperative Corporation,'' which can be found in Appendix B to the Arkansas Regional Haze SO_2 and PM BART SIP Revision.

[48] The Arkansas Regional Haze FIP assumed a 30-year equipment life in the PM BART analysis for AECC Bailey Unit 1. See 80 FR 18955.

[49] See ''BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations,'' dated March 2014, Version 4, prepared by Trinity Consultants Inc. in conjunction with Arkansas Electric Cooperative Corporation,'' Table 7–4, page 7–6. This BART analysis can be found in Appendix B to the Arkansas Regional Haze SO_2 and PM BART SIP Revision.

[50] See ''BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations,'' dated March 2014, Version 4, prepared by Trinity Consultants Inc. in conjunction with Arkansas Electric Cooperative Corporation,'' Table 5–9, page 5–9.

[51] See ''BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations,'' dated March 2014, Version 4, prepared by Trinity Consultants Inc. in conjunction with Arkansas Electric Cooperative Corporation,'' Table 5–9, column titled ''PM_{10} Cost Effectiveness,'' page 5–9.

[52] Based on Table 5–13 from AECC's SO_2 BART analysis, switching to diesel would result in an additional visibility benefit of 0.111 dv compared to switching to 1% No. 6 fuel oil, and in an additional visibility benefit of only 0.075 dv compared to switching to 0.5% No. 6 fuel oil at Mingo, which is the Class I area with the greatest visibility impacts from Bailey Unit 1. Based on

believe that switching to fuel with 0.5% or less sulfur content is within the range that has generally been considered to be cost-effective for BART and since the source will have to comply with that same requirement for SO_2 BART, we consider it appropriate to require it under PM BART as well. Therefore, we are proposing to approve ADEQ's determination that PM BART for AECC Bailey Unit 1 is no additional control beyond switching to fuel with 0.5% or less sulfur content by October 27, 2021. Additionally, the owner or operator of the unit shall not purchase fuel for combustion at the unit that does not meet this sulfur content limit as of the effective date of the Administrative Order, which is August 7, 2018. This BART determination has now been made enforceable by the state through an Administrative Order that has been adopted and incorporated in the SIP revision. We are proposing to approve into the SIP the state's Administrative Order with respect to the PM BART requirements for AECC Bailey Unit 1.[53]

The state's PM BART decision for Bailey Unit 1 is consistent with the BART decision EPA previously made in the FIP we promulgated on September 27, 2016.[54] We are concurrently proposing to withdraw the FIP's PM BART requirements for Bailey Unit 1, as they would be replaced by our approval of the state's PM BART decision.

2. AECC McClellan Unit 1

The AECC McClellan Unit 1 has a wall-fired boiler, a gross output of 122 MW and a maximum heat input rate of 1,436 MMBtu/hr. The unit is currently permitted to burn pipeline quality natural gas and fuel oil. The fuel oil burned is currently subject to a sulfur content limit of 2.8% by weight. AECC produced BART analyses dated March 2014 for McClellan Unit 1, which were evaluated by EPA and largely formed the basis for EPA's SO_2 and PM BART evaluations in the FIP.[55] The same BART analyses[56] have now been adopted and incorporated by ADEQ into the Arkansas Regional Haze SO_2 and PM BART SIP revision to address the SO_2 and PM BART requirements for McClellan Unit 1.

a. SO_2 BART Analysis and Determination

In assessing SO_2 BART, ADEQ explained that AECC considered the five BART factors. In assessing feasible control technologies and their effectiveness, AECC considered FGD systems and fuel switching during fuel oil burning. Due to the intrinsically low sulfur content of natural gas, no control technologies were evaluated for natural gas burning scenarios. As such, the BART analysis focused on fuel oil firing as the base case. For fuel oil firing, fuel switching was determined to be the only technically feasible control option, and thus AECC did not further consider FGD for SO_2 BART. The baseline fuel AECC assumed in the BART analysis is No. 6 fuel oil with 1.38% sulfur content by weight, which is based on the average sulfur content of the fuel oil from the most recent shipment received by the facility in April 2009. ADEQ explained that AECC evaluated switching to the following fuel types: 1% Sulfur No. 6 fuel oil, corresponding to an estimated 28% control efficiency; 0.5% sulfur No. 6 fuel oil, corresponding to 64% control efficiency; and 0.05% sulfur diesel, corresponding to 96% control efficiency.[57]

In considering the costs of compliance for fuel switching, AECC concluded that the fuel switching options evaluated would not require capital investments in equipment, but instead the annual costs would be based upon operation and maintenance costs associated with the different fuel types. AECC estimated that the cost-effectiveness of switching McClellan Unit 1 to No. 6 fuel oil with 1% and 0.5% sulfur content by weight is $2,613/ton and $3,823/ton, respectively. Switching to diesel, which has 0.05% sulfur content, is estimated to cost $7,145/ton. ADEQ stated that the cost in dollars per ton for diesel is out of the range of what is typically considered cost-effective, while the cost of both 1% and 0.5% sulfur No. 6 fuel oil is estimated to be within the range of what is typically considered cost-effective.

ADEQ stated that AECC's evaluation did not identify any energy or non-air quality environmental impacts associated with switching to 1% sulfur No. 6 fuel oil, 0.5% sulfur No. 6 fuel oil, or diesel. In assessing the remaining useful life of McClellan Unit 1, AECC concluded that this factor does not impact the annualized costs of the evaluated control options since fuel switching is not expected to require any significant capital costs in this case.

In assessing visibility impacts, the state's submittal included CALPUFF modeling evaluating the visibility benefits of switching from the baseline fuel (assuming 100% use of fuel oil) to the various fuel switching options. We summarize the results of that modeling in Table 4.

TABLE 4—ANTICIPATED VISIBILITY BENEFIT DUE TO FUEL SWITCHING AT AECC MCCLELLAN UNIT 1
[CALPUFF, 98th percentile]

Class I area	Baseline visibility impact (dv)	Visibility benefit of controls over baseline (dv)		
		No. 6 fuel oil—1% sulfur	No. 6 fuel oil—0.5% sulfur	Diesel—0.05% sulfur
Caney Creek	0.622	0.085	0.300	0.448
Upper Buffalo	0.266	0.035	0.120	0.193
Hercules-Glades	0.231	0.029	0.116	0.169

Table 5–9 from AECC's SO_2 BART analysis, the corrected cost of switching to 1% and 0.5% No. 6 fuel oil is estimated to be $1,165/ton of PM removed and $2,998/ton of PM removed (respectively), while the corrected cost of diesel is estimated to be $7,608/ton of PM removed. We do not consider the additional cost of switching to diesel at Bailey Unit 1 to be warranted by the additional level of anticipated visibility benefit.

[53] The Administrative Order can be found in the Arkansas Regional Haze SO_2 and PM BART SIP Revision.

[54] The Arkansas Regional Haze FIP required Bailey Unit 1 to only use fuel with a sulfur content limit of 0.5% by weight, with a compliance date of October 27, 2021. Additionally, the FIP prohibited the owner or operator of the unit from purchasing fuel for combustion at the unit that does not meet the sulfur content limit; the compliance date for this requirement was October 27, 2016. See 81 FR 66335 and 66415–16.

[55] 80 FR 18957.

[56] "BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations," dated March 2014, Version 4, prepared by Trinity Consultants Inc. in conjunction with Arkansas Electric Cooperative Corporation," which can be found in Appendix B to the Arkansas Regional Haze SO_2 and PM BART SIP Revision.

[57] We also note that AECC evaluated switching to natural gas as an available SO_2 control option in its SO_2 BART analysis, but the evaluation of this control option was not discussed by ADEQ in the SIP revision. We discuss this issue in greater detail below when we present our evaluation of the state's BART determination.

TABLE 4—ANTICIPATED VISIBILITY BENEFIT DUE TO FUEL SWITCHING AT AECC MCCLELLAN UNIT 1—Continued
[CALPUFF, 98th percentile]

Class I area	Baseline visibility impact (dv)	Visibility benefit of controls over baseline (dv)		
		No. 6 fuel oil—1% sulfur	No. 6 fuel oil—0.5% sulfur	Diesel—0.05% sulfur
Mingo	0.228	0.035	0.092	0.148

Switching to 1% sulfur No. 6 fuel oil is anticipated to achieve visibility benefits of approximately 0.085 dv at Caney Creek, 0.035 dv at Upper Buffalo, 0.029 dv at Hercules-Glades, and 0.035 dv at Mingo over baseline visibility conditions. Switching to 0.5% sulfur No. 6 fuel oil is anticipated to achieve visibility benefits of approximately 0.300 dv at Caney Creek, 0.120 dv at Upper Buffalo, 0.116 dv at Hercules-Glades, and 0.092 dv at Mingo over the baseline. The visibility benefits of switching to diesel are anticipated to be even greater, with benefits of approximately 0.448 dv at Caney Creek, 0.193 dv at Upper Buffalo, 0.169 dv at Hercules-Glades, and 0.148 dv at Mingo over the baseline.

Taking into consideration the cost-effectiveness and the anticipated visibility improvement of the fuel switching options, ADEQ concurred with AECC's recommendation that SO_2 BART for AECC McClellan Unit 1 be determined to be the use of fuel with a sulfur content by weight of 0.5% or less.

We note that switching to diesel would result in additional reductions in SO_2 emissions, but the additional costs per ton for doing so would be high in comparison to the additional visibility benefits. We also note that AECC evaluated switching to natural gas as an available SO_2 control option in its SO_2 BART analysis,[58] but the evaluation of this control option in the SO_2 BART analysis was not discussed by ADEQ in the SIP revision. In its analysis, AECC explained that switching to natural gas may have an adverse energy impact during periods of natural gas curtailment and that the ability to burn both fuel oil and natural gas was important for the facility to maintain electrical reliability.[59] Therefore, AECC did not recommend switching to natural gas and instead recommended switching to fuels with 0.5% sulfur content to be SO_2 BART for McClellan Unit 1.[60] In the Arkansas Regional Haze FIP, we agreed with AECC's recommendation, and explained that the BART Guidelines provide that it is not our intent to direct subject-to-BART sources to switch fuel forms, such as from coal or fuel oil to natural gas (40 CFR part 51, Appendix Y, section IV.D.1).[61] We noted that since natural gas has a sulfur content by weight that is well below 0.5%, the facility may elect to use this type of fuel to comply with BART, but we did not require a switch to natural gas for SO_2 BART in the FIP.[62] Therefore, we do not find that ADEQ's lack of consideration of switching to natural gas as an SO_2 control option in the SO_2 BART analysis for McClellan Unit 1 changes the result of the BART analysis in this instance. We are proposing to approve the state's determination that SO_2 BART for McClellan Unit 1 is the use of fuel with a sulfur content by weight of 0.5% or less. We are also proposing to approve the state's determination that McClellan Unit 1 must comply with this BART requirement no later than October 27, 2021, and that as of the effective date of the Administrative Order, which is August 7, 2018, the source shall not purchase fuel that does not meet the sulfur limit requirement for combustion at McClellan Unit 1. These BART requirements have now been made enforceable by the state through an Administrative Order that has been adopted and incorporated in the SIP revision. The Administrative Order for AECC McClellan Unit 1 includes not only the requirement to limit the sulfur content of the fuel burned, but also requirements for the source to sample and analyze each shipment of fuel to determine the sulfur content by weight and maintain records pertaining to the sampling of each fuel shipment to assess compliance with the BART requirements.[63] We are proposing to approve the state's Administrative Order, including the compliance determination requirements contained in the Administrative Order, into the SIP. The state's SO_2 BART emission limit and compliance date for McClellan Unit 1 are consistent with the BART decision EPA previously made in the FIP we promulgated on September 27, 2016.[64] We are concurrently proposing to withdraw the FIP's SO_2 BART requirements for McClellan Unit 1, as they would be replaced by our approval of the state's SO_2 BART decision.

b. PM BART Analysis and Determination

PM emissions are inherently low when burning natural gas, but are higher when burning fuel oil. McClellan Unit 1 does not currently have pollution control equipment for PM emissions. In assessing PM BART for McClellan Unit 1, ADEQ explained that AECC considered the five BART factors. In assessing feasible control technologies and their effectiveness, AECC considered the following control technologies for PM BART: Dry ESP, wet ESP, fabric filter, wet scrubber, cyclone, and fuel switching. AECC's evaluation noted that the particulate matter from oil-fired boilers tends to be sticky and small, affecting the collection efficiency of dry ESPs and fabric filters. Dry ESPs operate by placing a charge on the particles through a series of electrodes, and then capturing the charged particles on collection plates,

[58] See "BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations, dated March 2014, Version 4, prepared by Trinity Consultants Inc. in conjunction with Arkansas Electric Cooperative Corporation," pages 5–1 to 5–14. This BART analysis has been adopted and incorporated by ADEQ into the SIP revision (see Appendix B to the Arkansas Regional Haze SO_2 and PM BART SIP revision).

[59] See "BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations, dated March 2014, Version 4, prepared by Trinity Consultants Inc. in conjunction with Arkansas Electric Cooperative Corporation," pages 5–2, 5–10, and 5–14.

[60] *Id.*

[61] See 80 FR at 18959 and 81 FR at 66340.

[62] *Id.*

[63] The Administrative Order can be found in the Arkansas Regional Haze SO_2 and PM BART SIP Revision.

[64] The Arkansas Regional Haze FIP requires McClellan Unit 1 to only use fuel with a sulfur content limit of 0.5% by weight, with a compliance date of October 27, 2021. Additionally, the FIP prohibits the owner or operator of the unit from purchasing fuel for combustion at the unit that does not meet the sulfur content limit; the compliance date for this requirement is October 27, 2016. See 81 FR 66335 and 66415–16.

while fabric filters work by filtering the PM in the flue gas through filter bags. The collected particles are periodically removed from the filter bag through a pulse jet or reverse flow mechanism. Because of the sticky nature of particles from oil-fired boilers, AECC considered dry ESPs and fabric filters to be technically infeasible for use at McClellan Unit 1. AECC found wet ESPs, wet scrubbers, cyclones, and fuel switching to be technically feasible PM control options.

Residual fuel, such as the baseline No. 6 fuel oil burned at McClellan Unit 1, has inherent ash that contributes to emissions of filterable PM. Reductions in filterable PM emissions are directly related to the sulfur content of the fuel. Therefore, switching to No. 6 fuel oil with a lower sulfur content is expected to result in lower filterable PM emissions. Also, ash content is much lower in a distillate fuel such as diesel and essentially zero in natural gas. The fuel switching options considered by AECC in the BART analysis are No. 6 fuel oil with 1% sulfur content by weight, No. 6 fuel oil with 0.5% sulfur content by weight, natural gas, and diesel. AECC estimated that switching to a lower sulfur fuel has a PM control efficiency ranging from approximately 44%–99%, depending on the fuel type. The estimated PM control efficiency of each control option is summarized in Table 5.

TABLE 5—PM CONTROL EFFICIENCY OF BART CONTROL OPTIONS FOR AECC MCCLELLAN UNIT 1

PM control option	Wet scrubber	Cyclone	Wet ESP	Fuel switching			
				No. 6 fuel oil—1% S	No. 6 fuel oil—0.5% S	Natural gas	Diesel
PM Control Efficiency (%)	55.0	85.0	90.0	43.6	82.4	99.0	99.2

In considering the costs of the PM control options, AECC noted that add-on controls such as the wet scrubber, cyclone, and wet ESP involve capital costs for new equipment, which AECC annualized over a 15-year period in the analysis. Based on this analysis, AECC determined that the estimated cost-effectiveness of the add-on control options are as follows: $695,549/ton for a wet scrubber; $14,882/ton for a cyclone; and $266,237/ton for a wet ESP. AECC determined that the estimated cost-effectiveness of the fuel switching options are as follows: $53,044/ton for No. 6 fuel oil with 1% sulfur content; $31,338/ton for No. 6 fuel oil with 0.5% sulfur content; $32,952/ton for diesel; and $571/ton for natural gas. AECC noted that it does not consider any of the PM control options to be cost-effective.

ADEQ explained that AECC's PM BART evaluation did not discuss any energy or non-air quality environmental impacts associated with fuel switching. AECC did identify certain energy and non-air quality environmental impacts associated with wet ESPs and wet scrubbers. These impacts, which are factored in the cost of compliance, include increased energy usage for operation of the control equipment, the generation of wastewater streams that must be treated on-site or sent to a waste water treatment plant, and the generation of a filter cake that would likely require land-filling. In assessing the remaining useful life of McClellan Unit 1, AECC concluded that this factor does not impact the annualized costs of the evaluated control options since the remaining useful life of McClellan Unit 1 is at least as long as the capital cost recovery period of 15 years.

In assessing visibility impacts, the state's submittal included CALPUFF modeling evaluating the visibility benefits of switching from the baseline fuel oil (assuming 100% use of fuel oil) to the various fuel switching options. We summarize the results of that modeling in Table 6.

TABLE 6—ANTICIPATED VISIBILITY BENEFIT OF PM CONTROLS AT AECC MCCLELLAN UNIT 1

[CALPUFF, 98th percentile]

Class I area	Baseline visibility impact (dv)	Visibility benefit of controls over baseline (dv) [65]						
		Wet scrubber	Cyclone	Wet ESP	No. 6 fuel oil—1% sulfur	No. 6 fuel oil—0.5% sulfur	Diesel—0.05% sulfur	Natural gas
Caney Creek	0.621	0.002	0.002	0.004	0.085	0.300	0.448	0.497
Upper Buffalo	0.266	0.002	0.001	0.003	0.035	0.120	0.193	0.214
Hercules-Glades	0.230	0.002	0.001	0.003	0.029	0.116	0.169	0.191
Mingo	0.227	0.003	0.002	0.004	0.035	0.092	0.148	0.17

The anticipated visibility benefits of add-on controls (*i.e.,* wet scrubber, cyclone, and wet ESP) are very small, ranging from 0.001 to 0.004 dv at each affected Class I area. As discussed above, fuel switching to lower sulfur fuels is expected to result in both lower filterable PM emissions and lower SO_2 emissions. Switching to 1% sulfur No. 6 fuel oil is anticipated to achieve visibility benefits of approximately 0.085 dv at Caney Creek, 0.035 dv at Upper Buffalo, 0.029 dv at Hercules-Glades, and 0.035 dv at Mingo over baseline visibility conditions. Switching to 0.5% sulfur No. 6 fuel oil is anticipated to achieve visibility benefits of approximately 0.3 dv at Caney Creek, 0.12 dv at Upper Buffalo, 0.116 dv at Hercules-Glades, and 0.092 dv at Mingo over the baseline. The visibility benefits of switching to diesel are anticipated to be even greater, with benefits of approximately 0.448 dv at Caney Creek, 0.193 dv at Upper Buffalo, 0.169 dv at

[65] The modeled visibility improvement of the fuel switching options reflects both SO_2 and PM emissions reductions since reductions in filterable PM are directly related to the sulfur content of the fuel.

Hercules-Glades, and 0.148 dv at Mingo over the baseline. The visibility benefits of switching to natural gas are anticipated to be only slightly more than switching to diesel. The modeled visibility improvement of switching to lower sulfur fuels reflects benefits of both SO_2 and PM emissions reductions since reductions in filterable PM are directly related to the sulfur content of the fuel. We do note that the majority of the baseline visibility impact at each Class I area when burning the baseline fuel oil is due to SO_2 emissions that form sulfate PM, while direct PM_{10} emissions contribute only a small portion of the baseline visibility impacts at each Class I area.[66] Accordingly, the majority of the visibility improvement associated with switching to lower sulfur fuels, as shown in Table 6, can reasonably be expected to be the result of a reduction in SO_2 emissions rather than PM emissions.

Taking into consideration the cost-effectiveness and the anticipated visibility improvement of the PM control options considered, ADEQ concluded that add-on controls are not cost-effective, with AECC estimating the cost of these controls to be approximately $15,000/ton and greater. ADEQ concluded that the cost of switching to lower sulfur fuels is also not a cost-effective method for reducing PM emissions. However, ADEQ noted that the SO_2 BART determination for McClellan Unit 1, which is the use of fuel that has 0.5% or less sulfur content by weight, would also result in PM emissions reductions. ADEQ therefore arrived at the determination that PM BART for McClellan Unit 1 is no additional control beyond switching to fuel with 0.5% or less sulfur content, consistent with the SO_2 BART decision for the unit.

We do not agree with the use of a 15-year capital cost recovery period for calculating the average cost-effectiveness of a wet ESP, wet scrubber, and cyclone. Per the EPA Control Cost Manual, facilities are to rely on a 30-year capital cost recovery period for calculating the average cost-effectiveness of a wet ESP, wet scrubber, or cyclone barring a technical rationale to deviate from the 30-year capital cost recovery period. AECC Bailey Generating Station did not provide a technical rationale to deviate from the assumed 30-year capital cost recovery period. In addition, we are not aware of any enforceable shutdown date for the AECC McClellan Generating Station, nor did AECC's evaluation or ADEQ's SIP revision indicate any future planned shutdown or provide any reason for adopting a 15-year equipment life for the controls under consideration. Therefore, we believe that assuming a 30-year equipment life rather than a 15-year equipment life would be more appropriate for these control technologies.[67] Extending the amortization period from 15 to 30 years has the effect of decreasing the total annual cost of each control option, thereby improving the average cost-effectiveness value of controls (*i.e.,* lower dollars per ton removed). As discussed above, the cost of add-on PM control equipment at McClellan Unit 1, assuming a 15-year remaining useful life, ranges from $14,882/ton of PM removed for a cyclone to $695,549/ton of PM removed for a wet scrubber. Even though adjusting the costs of the add-on controls based on a 30-year remaining useful life as opposed to a 15-year remaining useful life would decrease the $/ton costs, we anticipate that the costs in $/ton would still be considerable and well outside of the range that has generally been considered to be cost-effective for BART. Therefore, we believe that add-on PM controls would still not be justified in light of the considerable costs and the minimal visibility benefits, which would range from 0.001 to 0.004 at each Class I area (see Table 6 above). Therefore, we are proposing to agree with ADEQ's determination that PM add-on controls are not PM BART for McClellan Unit 1.

We also disagree with the total annual cost and cost-effectiveness values for fuel switching presented in AECC's PM BART analysis[68] and in the SIP revision. In AECC's SO_2 BART cost analysis for the same unit, the company considered the same fuel switching options, yet the total annual cost numbers presented in the PM cost analysis are significantly greater than those presented in the SO_2 cost analysis.[69] This appears to be because in the SO_2 cost analysis, AECC calculated the differential cost of fuel switching (*i.e.,* the difference in cost between the baseline fuel and the fuel switching options), whereas the absolute cost of the fuel switching options was calculated in the PM cost analysis. We believe that AECC and ADEQ should have considered the differential cost of fuel switching as opposed to the absolute cost of fuel for each of the fuel switching options in the PM BART analysis, as was done in the SO_2 BART analysis. Thus, we believe that the correct cost effectiveness values that ADEQ should have considered in the PM BART analysis are those presented in Table 5–10 of AECC's SO_2 BART analysis,[70] which shows that the costs of switching to fuel oil with a sulfur content of 1% or 0.5% are within the range that have generally been considered to be cost effective for BART. Although switching to diesel would result in additional reductions in PM emissions, we believe that the additional cost per ton for switching to diesel would be high in comparison to the additional visibility benefits.[71] We believe that switching to fuel with 0.5% or less sulfur content is within the range that has generally been considered to be cost-effective for BART and since the source will have to comply with that same requirement for SO_2 BART, we consider it appropriate to require it under PM BART as well. Therefore, we are proposing to approve ADEQ's determination that PM BART for AECC McClellan Unit 1 is no additional control beyond switching to fuel with 0.5% or less sulfur content by October 27, 2021. Additionally, the owner or

[66] See Table 4–5 BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO McCLELLAN, UNIT 1 (2001–2003)—FUEL OIL, ''BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations,'' dated March 2014, Version 4, prepared by Trinity Consultants Inc. in conjunction with Arkansas Electric Cooperative Corporation,'' which can be found in Appendix B to the Arkansas Regional Haze SO_2 and PM BART SIP Revision.

[67] The Arkansas Regional Haze FIP assumed a 30-year equipment life in the PM BART analysis for AECC McClellan Unit 1. See 80 FR 18962.

[68] See ''BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations,'' dated March 2014, Version 4, prepared by Trinity Consultants Inc. in conjunction with Arkansas Electric Cooperative Corporation,'' Table 7–5, page 7–6. This BART analysis can be found in Appendix B to the Arkansas Regional Haze SO_2 and PM BART SIP Revision.

[69] See ''BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations,'' dated March 2014, Version 4, prepared by Trinity Consultants Inc. in conjunction with Arkansas Electric Cooperative Corporation,'' Table 5–10, page 5–9.

[70] See ''BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations,'' dated March 2014, Version 4, prepared by Trinity Consultants Inc. in conjunction with Arkansas Electric Cooperative Corporation,'' Table 5–10, column titled ''PM_{10} Cost Effectiveness,'' page 5–9.

[71] Based on Table 5–14 from AECC's SO_2 BART analysis, switching to diesel would result in an additional visibility benefit of 0.363 dv compared to switching to 1% No. 6 fuel oil and in an additional visibility benefit of only 0.148 dv compared to switching to 0.5% No. 6 fuel oil at Caney Creek, which is the Class I area with the greatest visibility impacts from McClellan Unit 1. Based on Table 5–10 from AECC's SO_2 BART analysis, the corrected costs of switching to 1% and 0.5% No. 6 fuel oil is estimated to be $2,457/ton of PM removed and $4,553/ton of PM removed (respectively), while the corrected cost of switching to diesel is estimated to be $10,698/ton of PM removed. We do not consider the additional cost of switching to diesel at McClellan Unit 1 to be

operator of the unit shall not purchase fuel for combustion at the unit that does not meet this sulfur content limit as of the effective date of the Administrative Order, which is August 7, 2018. This BART determination has now been made enforceable by the state through an Administrative Order that has been adopted and incorporated in the SIP revision. We are proposing to approve into the SIP the state's Administrative Order with respect to the PM BART requirements for AECC McClellan Unit 1.[72]

The state's PM BART decision for McClellan Unit 1 is consistent with the BART decision EPA previously made in the FIP we promulgated on September 27, 2016.[73] We are concurrently proposing to withdraw the FIP's PM BART requirements for McClellan Unit 1, as they would be replaced by our approval of the state's PM BART decision.

3. SWEPCO Flint Creek Plant Boiler No. 1

SWEPCO Flint Creek Plant Boiler No. 1 has a 558 MW dry bottom wall-fired boiler that commenced operation in 1978, has a maximum heat input of 6,324 MMBtu/hr, and burns low sulfur western coal as a primary fuel, but is also permitted to combust fuel oil and tire-derived fuels. Fuel oil firing is only allowed during unit startup and shutdown, during startup and shutdown of pulverizer mills, for flame stabilization when coal is frozen, for No. 2 fuel oil tank maintenance, to prevent boiler tube failure in extreme cold weather when the unit is offline for maintenance, and during malfunction.

SWEPCO produced a BART analysis dated September 2013 for Flint Creek Plant Boiler No. 1, which was evaluated by EPA and largely formed the basis for EPA's SO_2 BART evaluation in the FIP.[74] This BART analysis[75] has now been adopted and incorporated by ADEQ into the Arkansas Regional Haze SO_2 and PM BART SIP revision to address the SO_2 BART requirements for Flint Creek Boiler No. 1.[76]

a. SO_2 BART Analysis and Determination

At the time that SWEPCO performed the BART analysis, no SO_2 controls were in place at Flint Creek Plant Boiler No. 1. The cost analysis and visibility improvement data that are part of SWEPCO's BART analysis are based on the 2001–2003 baseline, not on emissions reflecting current SO_2 controls in place. Since the time the BART analysis was developed, SWEPCO has installed a Novel Integrated Deacidification (NID) system and Activated Carbon Injection (ACI) system at Flint Creek Boiler No. 1 in anticipation of regional haze requirements as well as other CAA requirements. The installation of these controls was completed in May 2016.

In assessing SO_2 BART, SWEPCO considered the five BART factors. The available SO_2 retrofit control technology options considered were dry sorbent injection (DSI), dry FGD, and wet FGD.[77] DSI was estimated to have a control efficiency of 40–60%. Dry FGD was estimated to have a control efficiency of 60–95%. NID, which is a form of dry FGD, was predicted to have a control efficiency of 92%, achieving an SO_2 emission rate of 0.06 lb/MMBtu. Wet FGD was estimated to have a control efficiency of 80–95%, achieving an SO_2 emission rate of 0.04 lb/MMBtu. All control options considered were deemed to be technically feasible.

In considering the costs of compliance, SWEPCO estimated the capital and operating costs of a NID system and wet FGD based on EPA's Control Cost Manual and supplemented, where available, with vendor and site-specific information obtained by SWEPCO. These values were then used by SWEPCO to estimate the cost-effectiveness of controls. SWEPCO estimated the cost of the SO_2 control options to be $3,845/ton for a NID system and $4,919/ton for wet FGD. Since control options with higher control efficiencies were within a range considered cost-effective (with one ultimately selected as BART), SWEPCO's BART analysis did not evaluate the cost of DSI or further consider that control option in the analysis. Thus, the remainder of SWEPCO's analysis focused on a NID system (dry FGD) and wet FGD.

SWEPCO determined that although wet FGD is expected to achieve a slightly higher level of SO_2 control compared to NID technology, it would also have greater potential negative energy and nonair quality environmental impacts. For example, wet FGD is expected to generate large volumes of wastewater and solid waste/sludge that must be treated. Additionally, wet FGD systems have increased power requirements and increased reagent usage over dry FGD, as well as the potential for increased particulate and sulfuric acid mist releases. The costs associated with increased power requirements and greater reagent usage have already been factored into the cost analysis for wet FGD. In assessing the remaining useful life of Flint Creek Boiler No. 1, SWEPCO concluded that this factor does not impact the annualized capital costs of the evaluated control options because the useful life of the unit is anticipated to be at least as long as the capital cost recovery period (30 years).

In assessing visibility impacts, the state's submittal included CALPUFF modeling evaluating the visibility benefits of dry FGD and wet FGD. We summarize the results of that modeling in Table 7.

warranted by the additional level of anticipated visibility benefit.

[72] The Administrative Order can be found in the Arkansas Regional Haze SO_2 and PM BART SIP Revision.

[73] The Arkansas Regional Haze FIP required McClellan Unit 1 to only use fuel with a sulfur content limit of 0.5% by weight, with a compliance date of October 27, 2021. Additionally, the FIP prohibited the owner or operator of the unit from purchasing fuel for combustion at the unit that does not meet the sulfur content limit; the compliance date for this requirement was October 27, 2016. See 81 FR 66335 and 66415–16.

[74] 80 FR 18964.

[75] ''BART Five Factor Analysis Flint Creek Power Plant Gentry, Arkansas (AFIN 04–00107),'' dated September 2013, Version 4, prepared by Trinity Consultants Inc. in conjunction with American Electric Power Service Corporation for the Southwestern Electric Power Company Flint Creek Power Plant,'' which can be found in Appendix E to the Arkansas Regional Haze SO_2 and PM BART SIP Revision.

[76] In a final action published on March 12, 2012, EPA approved Arkansas' PM BART determination for Flint Creek Plant Boiler No. 1. In the Arkansas Regional Haze SO_2 and PM BART SIP revision, the state is not revising that BART determination or the underlying analysis.

[77] SWEPCO's September 2013 SO_2 BART analysis did not identify or discuss any existing SO_2 control equipment in use at the source because at the time the BART analysis was developed, there were no existing SO_2 controls in place. Since the Arkansas Regional Haze SO_2 and PM SIP revision was submitted at a time when the NID system is the pollution control equipment in use at the source, we give ADEQ credit for considering the existing pollution controls factor in the SIP revision because the existing SO_2 control equipment is among the ''new'' controls addressed in the older SWEPCO SO_2 BART analysis.

TABLE 7—ANTICIPATED VISIBILITY BENEFIT DUE TO SO_2 CONTROLS AT FLINT CREEK BOILER NO. 1
[CALPUFF, 98th percentile]

Class I area	Baseline visibility impact (dv)	Visibility benefit of controls over baseline (dv)	
		NID System	Wet FGD
Caney Creek	0.963	0.615	0.629
Upper Buffalo	0.965	0.464	0.477
Hercules-Glades	0.657	0.345	0.352
Mingo	0.631	0.414	0.423

The installation and operation of SO_2 controls is anticipated to result in considerable visibility improvement from the baseline at the four impacted Class I areas. NID technology is anticipated to result in visibility improvement ranging from 0.345 to 0.615 dv at each affected Class I area. Although wet FGD is also anticipated to result in considerable visibility improvement, the visibility benefit of wet FGD over NID technology at each individual Class I area is anticipated to be only slight, ranging from 0.007 to 0.014 dv at each Class I area.

As discussed above, SWEPCO determined that NID technology would result in considerable visibility improvement and is estimated to cost $3,845/ton. On the other hand, a wet scrubber is estimated to cost $4,919/ton, and would only achieve slightly more visibility benefit than NID technology (see Table 7).[78] Therefore, SWEPCO recommended that SO_2 BART for Flint Creek Boiler No. 1 be an emission limit of 0.06 lb/MMBtu on a 30-day rolling average over each boiler operating day, based on the installation of NID technology. ADEQ concurred with this BART recommendation. We are proposing to agree that an SO_2 emission limit of 0.06 lb/MMBtu based on NID technology would result in significant visibility benefits from the baseline and is generally cost-effective. We do not believe the additional cost of a wet scrubber would be justified in light of the small amount of additional visibility benefit anticipated over NID technology. Therefore, we are proposing to approve the state' determination that SO_2 BART for Flint Creek Boiler No. 1 is an emission limit of 0.06 lb/MMBtu based on NID technology.

Taking into consideration that the control equipment has already been installed and is operating at the facility, we are also proposing to approve the state's determination that the source must comply with the SO_2 BART requirements as of the effective date of the Administrative Order, which is August 7, 2018. These BART requirements have now been made enforceable by the state through an Administrative Order that has been adopted and incorporated in the SIP revision. The Administrative Order for Flint Creek Boiler No. 1 includes not only the SO_2 emission limit, but also a requirement for the source to determine compliance with the SO_2 emission limit by using a continuous emission monitoring system.[79] We are proposing to approve into the SIP the state's Administrative Order with respect to the SO_2 BART requirements, including the compliance determination requirements contained in the Administrative Order. The state's SO_2 BART decision for Flint Creek Boiler No. 1 is consistent with the BART decision EPA previously made in the FIP we promulgated on September 27, 2016.[80] We are concurrently proposing to withdraw the FIP's SO_2 BART requirements for Flint Creek Boiler No. 1, as they would be replaced by our approval of the state's SO_2 BART decision.

4. Entergy Lake Catherine Unit 4

Entergy Lake Catherine Unit 4 has a 558 MW tangentially-fired boiler with a maximum heat input of 5,850 MMBtu/hr. Lake Catherine Unit 4 is currently permitted to burn only pipeline quality natural gas, but until recently was also permitted to burn No. 6 fuel oil as a secondary fuel. Entergy produced a BART analysis dated May 2014 for Lake Catherine Unit 4, which was evaluated by EPA and largely formed the basis for EPA's BART evaluation in the FIP.[81] The same BART analysis[82] has now been adopted and incorporated by ADEQ into the Arkansas Regional Haze SO_2 and PM BART SIP revision to address BART requirements for Lake Catherine Unit 4 under the fuel oil firing scenario.[83]

In the May 2014 BART analysis submitted by ADEQ as part of the SIP revision, Entergy explained that no fuel oil has been burned at Unit 4 since prior to the 2001–2003 baseline period and that the company does not project that it will burn fuel oil at the unit in the foreseeable future. Therefore, the May 2014 BART analysis does not consider emissions from fuel oil firing and does not include a BART five factor analysis or BART determinations for the fuel oil firing scenario. Entergy stated in the BART analysis that if conditions change such that it becomes economic to burn fuel oil in the future, it will submit a BART five factor analysis for the fuel oil firing scenario to the state for use in the development of a SIP revision, and that Entergy commits to not burn fuel oil at Lake Catherine Unit 4 until final EPA approval of BART for the fuel oil firing scenario. Furthermore, Unit 4 is not currently permitted to burn fuel oil.[84] Entergy's commitment has now been made enforceable by the state through an Administrative Order that has been adopted and incorporated in the SIP revision. We are proposing to find that

[78] Although not discussed by ADEQ in the SIP revision, SWEPCO's BART analysis also presents the incremental cost effectiveness of wet scrubbers over NID technology. As shown in Tables 5–3 and 5–7 of SWEPCO's September 2013 SO_2 BART analysis for Flint Creek, the incremental cost effectiveness of wet scrubbers over NID technology for Boiler No. 1 is estimated to be $35,198/ton removed, yet the incremental visibility benefit is projected to be only 0.014 dv at Caney Creek and 0.013 dv at Upper Buffalo and even less at Hercules Glades and Mingo.

[79] The Administrative Order can be found in the Arkansas Regional Haze SO_2 and PM BART SIP Revision.

[80] 81 FR 66335 and 66416–17.

[81] 80 FR 18975.

[82] ''Revised BART Five Factor Analysis Lake Catherine Steam Electric Station Malvern, Arkansas (AFIN 30–00011),'' dated May 2014, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc.,'' which can be found in Appendix C to the Arkansas Regional Haze SO_2 and PM BART SIP Revision.

[83] In a final action published on March 12, 2012, EPA approved Arkansas' SO_2 and PM BART determinations under the natural gas firing scenario for Lake Catherine Unit 4. In the Arkansas Regional Haze SO_2 and PM BART SIP revision, the state is not revising those BART determinations or any of the underlying analyses.

[84] See ADEQ Air Permit No. 1717–AOP–R7, issued on October 26, 2016. A copy of the air permit can be found in the docket for this proposed rulemaking.

this approach is appropriate and we are proposing to approve the state's Administrative Order for Lake Catherine Unit 4 into the SIP. The Administrative Order would allow the unit to burn natural gas only, per Entergy's commitment to not burn fuel oil at Unit 4 until ADEQ submits a SIP revision that includes BART analyses for the fuel oil firing scenario for Unit 4 and EPA takes final action to approve the BART determinations. The state's action with respect to addressing BART for the fuel oil firing scenario for Lake Catherine Unit 4 is consistent with the action EPA previously took in the FIP we promulgated on September 27, 2016.[85] We are concurrently proposing to withdraw the FIP provision concerning BART for the fuel oil firing scenario for Lake Catherine Unit 4, as it would be replaced by our approval of the state's BART action.

5. Entergy White Bluff Units 1 and 2 and the White Bluff Auxiliary Boiler

Entergy White Bluff Units 1 and 2 each have tangentially-fired 850 MW boilers with a maximum heat input capacity of 8,950 MMBtu/hr. White Bluff also has a 183 MMBtu/hr Auxiliary Boiler that is permitted to burn only No. 2 fuel oil or biodiesel. Entergy produced a BART analysis for White Bluff dated October 2013, which was evaluated by EPA and largely formed the basis for EPA's SO_2 BART evaluation in the FIP.[86] Entergy also submitted revised analyses dated August 2015 and August 2016 for EPA to consider before the FIP was finalized. Entergy provided ADEQ with supplemental information on April 5, 2017, providing cost-effectiveness data for dry FGD for Units 1 and 2 with various remaining useful life assumptions. Additionally, at ADEQ's request, Entergy produced an updated BART analysis dated August 18, 2017, that evaluated several control options and provided updated remaining useful life information for White Bluff Units 1 and 2. These BART analyses and other documentation provided by Entergy have been adopted and incorporated by ADEQ into the Arkansas Regional Haze SO_2 and PM BART SIP revision [87] to address the SO_2 BART requirements for White Bluff Units 1 and 2, as well as the SO_2, NO_X, and PM BART requirements for the Auxiliary Boiler.[88]

a. White Bluff Unit 1 and Unit 2 SO_2 BART Analysis and Determinations

In assessing SO_2 BART, Entergy considered the five BART factors. There is currently no SO_2 control equipment in use at Units 1 and 2. The current permitted SO_2 emissions rate for Units 1 and 2 is a 3-hour average emission rate of 1.2 lb/MMBtu, based on the new source performance standard for fossil-fuel fired steam generators in effect at the time they were constructed. The available SO_2 control technology options considered in Entergy's August 2017 BART analysis are switching to low sulfur coal, DSI, spray dryer absorber (SDA), circulating dry scrubber (CDS), and wet FGD.

Entergy estimated that by switching to low sulfur coal, Units 1 and 2 can achieve an emission rate of 0.6 lb/MMBtu,[89] which would result in approximately an 8.75% reduction in SO_2 emissions from baseline levels. For DSI, Entergy considered two particulate collection methods. The first collection method, ''DSI,'' would utilize the existing ESP, and is expected to achieve a control efficiency of 50%. Entergy expects that DSI would achieve an SO_2 emission rate of 0.35 lb/MMBtu. The second collection method, ''enhanced DSI,'' would require the installation of a fabric filter or baghouse. The use of a fabric filter or baghouse in enhanced DSI increases the residence time and improves the collection efficiency to allow more sorbent to be injected, thereby resulting in greater emissions reductions. Entergy expects that enhanced DSI would achieve 80% control efficiency, and an SO_2 emission rate of 0.15 lb/MMBtu. In the August 2017 BART analysis, Entergy claimed that DSI has not yet been demonstrated on units comparable to those at White Bluff. Entergy explained that the largest known installed and operational DSI system has a design feed rate of 12 tons/hour of sorbent, while most installed DSI systems typically inject approximately 5–6 tons/hour of sorbent into the exhaust gas stream. Entergy pointed out that the predicted injection rate of enhanced DSI at White Bluff is approximately 15 tons/hour of sorbent. Entergy noted that the greater the injection rates, it is anticipated that more issues associated with supply and delivery logistics are likely to arise. Entergy stated that before DSI technology is selected as BART for White Bluff, a demonstration test would need to be performed to confirm its feasibility, achievable performance, and balance of plant impacts (brown plume formation, ash handling modifications, landfill/leachate considerations, and impact to mercury control).

The dry FGD control option considered by Entergy is SDA, which utilizes a fine mist of lime slurry sprayed into an absorption tower to absorb SO_2 with the resulting calcium sulfite and calcium sulfate then collected with a fabric filter. SDA systems can typically achieve SO_2 control efficiencies ranging from 60–95%. Entergy expects that an SDA system would achieve an emission rate of 0.06 lb/MMBtu at Units 1 and 2. Although wet FGD was identified as a technically feasible control option, it is not expected to achieve significant visibility benefit beyond dry/semi-dry FGD despite having a greater estimated cost, based on the October 2013 BART analysis that EPA relied on to develop the Arkansas Regional Haze FIP.[90] In fact, dry/semi-dry FGD was expected to achieve slightly greater visibility benefit than wet FGD at Hercules-Glades and Mingo based on the October 2013 BART analysis.[91] Therefore, Entergy did not further consider wet FGD in its August 18, 2017, BART analysis, on which the Arkansas Regional Haze SO_2 and PM BART SIP revision is largely based.

In considering the costs of compliance, Entergy's coal suppliers provided the company with an estimated incremental cost of $0.50 per ton for delivering coal guaranteed to have a sulfur content consistent with achieving an SO_2 emission limit of 0.6 lb/MMBtu. ADEQ noted in the SIP revision that the annualized cost of switching to low sulfur coal is not dependent on the remaining useful life of White Bluff Units 1 and 2, since no capital investments in equipment would be necessary. For the remaining control options, Entergy obtained capital costs

[85] 81 FR 66335 and 66418.

[86] 80 FR 18969. See also ''Revised BART Five Factor Analysis White Bluff Steam Electric Station Redfield, Arkansas (AFIN 35–00110),'' dated October 2013, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc.'' This BART analysis can be found in Appendix D to the Arkansas Regional Haze SO_2 and PM BART SIP Revision.

[87] These BART analyses and other information provided by Entergy can be found in Appendix D to the Arkansas Regional Haze SO_2 and PM BART SIP Revision.

[88] In a final action published on March 12, 2012, EPA approved Arkansas' PM BART determinations for White Bluff Units 1 and 2. In the Arkansas Regional Haze SO_2 and PM BART SIP revision, the state is not revising those PM BART determinations or any of the underlying analyses.

[89] The White Bluff SO_2 BART analysis provided to ADEQ by Entergy and incorporated by ADEQ as part of the SIP revision considered an SO_2 emission limit of 0.6 lb/MMBtu for the switching to low sulfur coal control option. However, in response to comments the state received during the public comment period that noted that it is typical to round to the nearest significant digit when demonstrating compliance, which could result in less emissions reductions than assumed in the BART analysis, ADEQ ultimately finalized an emission limit of 0.60 lb/MMBtu in the final SIP revision.

[90] 80 FR 18972.

[91] 80 FR 18972.

and annual operating and maintenance costs from its consultant and used this to estimate the cost effectiveness of controls. The annualized cost of DSI, enhanced DSI, and dry/semi-dry FGD is dependent on the remaining useful life of the White Bluff units since those control options require capital investments in new equipment or retrofit of existing equipment. These capital investments were amortized over the remaining useful life of the White Bluff units to determine the annualized costs and compared to annual emission reductions to determine cost-effectiveness. In the August 18, 2017, BART analysis, Entergy stated that it anticipates cessation of coal combustion at White Bluff by the end of 2028 and that it will voluntarily take an enforceable restriction on Units 1 and 2 to that effect. ADEQ noted that the BART Guidelines provide that the remaining useful life calculation should begin on the date that controls will be put in place (*i.e.,* compliance date) and end on the date the facility permanently stops operations.[92] The Regional Haze Rule also states that the compliance date for BART controls must be as expeditiously as practicable, but in no event later than 5 years after approval of the SIP.[93] Considering that the FIP currently requires SO_2 emission limits for White Bluff Units 1 and 2 that are based on dry scrubber installation and which have a compliance date of October 27, 2021, ADEQ acknowledged that the record suggests that a compliance date for scrubbers that is ''as expeditiously as practicable'' would be October 27, 2021. Therefore, ADEQ assumed a remaining useful life of 7 years to estimate the cost-effectiveness of SDA for White Bluff Units 1 and 2. Entergy also assumed that DSI and enhanced DSI could be installed and operational 2 years earlier than FGD, and therefore assumed in the BART analysis that DSI and enhanced DSI could be operational at White Bluff Units 1 and 2 by the end of 2019 and that the capital recovery period for those controls is therefore 9 years.

Entergy also explained that for DSI, enhanced DSI, and SDA, it developed two sets of cost estimates. The first is the actual cost Entergy anticipates incurring for each control option, and the second reflects the exclusion of certain cost items that are disallowed costs under the methodology in the EPA's Air Pollution Control Cost Manual (EPA Control Cost Manual).[94] These ''disallowed'' line items include Allowance for Funds Used During Construction (AFUDC). Entergy stated in its BART analysis that it disagrees with EPA that AFUDC and certain other cost items are not allowed to be considered in estimating the cost effectiveness of controls for BART purposes under the EPA Control Cost Manual, but nonetheless provided a set of cost estimates reflecting the exclusion of the disallowed line items as well as a set of cost estimates that included these line items. ADEQ explained in the SIP revision that its evaluation of controls is based on Entergy's set of cost numbers that excludes the disallowed line items and follows the EPA Control Cost Manual. Therefore, we present here only the set of cost numbers that follows the methodology allowed under the Control Cost Manual.[95]

Entergy determined that switching to low sulfur coal would entail an increased annual cost of operation based on purchase contract terms for the specific sulfur content of the coal. Based on estimates provided by the coal supplier of the cost premium for low sulfur coal and the estimated reduction in emissions, Entergy anticipated that the cost to guarantee that the units achieve an SO_2 emission limit of 0.6 lb/MMBtu translates to a cost-effectiveness for SO_2 control of approximately $1,150/ton at Unit 1 and $1,148/ton at Unit 2. Entergy estimated the cost-effectiveness of DSI to be $6,269/ton at Unit 1 and $6,211/ton at Unit 2 and the cost-effectiveness of enhanced DSI to be $6,427/ton at Unit 1 and $6,384/ton at Unit 2. Entergy also estimated the cost of SDA to be $5,420/ton at Unit 1 and $5,387/ton at Unit 2. In the BART analysis, ADEQ also took into consideration the cost of controls in terms of dollars per dv improvement ($/dv) for each SO_2 control option considered for White Bluff. A summary of the cost of controls in terms of $/dv is provided in Table 8. A summary of Entergy's assessment of the visibility benefits of the control options in terms of dv is presented in Tables 9 and 10. ADEQ stated that the average cost-effectiveness values for DSI, enhanced DSI, and SDA at White Bluff all exceed what is typically considered to be cost-effective for BART, taking into account a capital cost recovery period of 7 years for SDA and 9 years for DSI and enhanced DSI. ADEQ noted that cost-effectiveness values of BART determinations made in previous regional haze actions have typically been below $5,000/ton, and that the costs of DSI and SDA exceed this value. Additionally, ADEQ noted that the cost in terms of $/dv for DSI, enhanced DSI, and SDA are approximately an order of magnitude greater than for switching to low sulfur coal.

TABLE 8—COST OF SO_2 CONTROLS ($/DV) FOR WHITE BLUFF UNITS 1 AND 2

SO_2 control option	Class I area			
	Caney Creek	Upper Buffalo	Hercules Glades	Mingo
Low Sulfur Coal	$14,500,519	$11,932,988	$10,666,332	$13,554,882
DSI	133,341,667	105,417,939	120,512,761	116,126,126
Enhanced DSI	158,855,956	139,165,572	168,897,541	173,433,064
SDA	131,447,683	121,373,255	153,165,608	153,852,117

[92] 70 FR 39104.

[93] 40 CFR 51.308(e)(iv).

[94] At the time the BART Guidelines were finalized, the current version of the Control Cost Manual was the *EPA Air Pollution Control Cost Manual, Sixth Edition,* EPA/452/B–02–001, January 2002. *https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.* The EPA is engaged in a long-term process to update portions of the Control Cost Manual. A project plan describing the scope and schedule for this update effort is available at *https://www3.epa.gov/ttn/ecas/docs/cost_manual_timeline_2016-08-04.pdf.* As draft or final updated chapters are available, states should follow the recommendations in those rather than in the 6th Edition. Final revised chapters are posted at *https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.* Draft revised chapters are announced in the **Federal Register** when available for public comment and can be obtained from EPA Docket No. EPA–HQ–OAR–2015–0341 at *www.regulationgs.gov.*

[95] Please see the TSD associated with this proposed rulemaking and the Arkansas Regional Haze SO_2 and PM SIP revision for Entergy's set of cost numbers that included line items that are not allowed to be considered in estimating the cost effectiveness of controls for BART purposes under the EPA Control Cost Manual.

In the BART analysis, Entergy noted that there were adverse energy and nonair quality environmental impacts associated with DSI, enhanced DSI, and SDA. These impacts were factored into the costs of compliance. With regard to consideration of the remaining useful life factor, Entergy stated in the August 2017 BART analysis that it anticipates cessation of coal combustion at White Bluff by the end of 2028 and that it will voluntarily take an enforceable restriction on Units 1 and 2 to that effect. Entergy's voluntary decision to cease coal combustion by the end of 2028 is enforceable by the state through an Administrative Order that has been adopted and incorporated in the SIP revision. Therefore, for White Bluff Units 1 and 2, ADEQ assumed a remaining useful life of 7 years to estimate the cost-effectiveness of SDA and a remaining useful life of 9 years to estimate the cost-effectiveness of DSI.

In assessing visibility impacts, the state's submittal included the CALPUFF modeling that was included in Entergy's August 18, 2017, BART analysis, evaluating the visibility benefits of switching to low sulfur coal, DSI, enhanced DSI, and SDA. We summarize the results of that modeling in Tables 9 and 10.[96]

TABLE 9—ANTICIPATED VISIBILITY BENEFIT DUE TO SO_2 CONTROLS AT WHITE BLUFF UNIT 1

[CALPUFF, 98th percentile] *

Class I area	Baseline visibility impact (dv)	Visibility benefit of controls over baseline (dv)			
		Low sulfur coal	DSI	Enhanced DSI	SDA
Caney Creek	1.505	0.129	0.308	0.492	0.603
Upper Buffalo	1.051	0.143	0.375	0.555	0.642
Hercules-Glades	0.925	0.167	0.341	0.467	0.525
Mingo	0.802	0.115	0.333	0.436	0.504

* This table shows the modeled visibility benefits of SO_2 controls for White Bluff Unit 1, as presented in Table 4–6 of Entergy's August 18, 2017, SO_2 BART analysis for White Bluff, which can be found in Appendix D of the Arkansas Regional Haze SO_2 and PM SIP revision. Although the combined visibility benefits on a facility-wide basis were not modeled, we expect that such combined visibility benefits would be greater than the unit specific values shown in this table.

TABLE 10—ANTICIPATED VISIBILITY BENEFIT DUE TO SO_2 CONTROLS AT WHITE BLUFF UNIT 2

[CALPUFF, 98th percentile] *

Class I area	Baseline visibility impact (dv)	Visibility benefit of controls over baseline (dv)			
		Low sulfur coal	DSI	Enhanced DSI	SDA
Caney Creek	1.533	0.097	0.274	0.460	0.574
Upper Buffalo	1.059	0.127	0.359	0.531	0.632
Hercules-Glades	0.912	0.137	0.303	0.429	0.486
Mingo	0.819	0.122	0.333	0.435	0.501

* This table shows the modeled visibility benefits of SO_2 controls for White Bluff Unit 2, as presented in Table 4–7 of Entergy's August 18, 2017, SO_2 BART analysis for White Bluff, which can be found in Appendix D of the Arkansas Regional Haze SO_2 and PM SIP revision. Although the combined visibility benefits on a facility-wide basis were not modeled, we expect that such combined visibility benefits would be greater than the unit specific values shown in this table.

The SO_2 control options considered are anticipated to result in considerable visibility improvement from the baseline at the four impacted Class I areas. For White Bluff Unit 1, switching to low sulfur coal is anticipated by the state submittal to result in visibility improvement ranging from 0.115 to 0.167 dv at each affected Class I area. DSI is anticipated to result in visibility improvement ranging from 0.308 to 0.375 dv at each affected Class I area, while enhanced DSI is anticipated to result in visibility improvement ranging from 0.436 to 0.555 dv. SDA is anticipated to result in the greatest visibility improvement, ranging from 0.504 to 0.642 dv.

For White Bluff Unit 2, switching to low sulfur coal is anticipated by the state submittal to result in visibility improvement ranging from 0.097 to 0.137 dv at each affected Class I area. DSI is anticipated to result in visibility improvement ranging from 0.274 to 0.359 dv at each affected Class I area, while enhanced DSI is anticipated to result in visibility improvement ranging from 0.429 to 0.531 dv. SDA is anticipated to result in the greatest visibility improvement, ranging from 0.486 to 0.632 dv.

[96] As explained by ADEQ in the SIP revision, Entergy's modeling of the visibility improvement from evaluated SO_2 controls in the August 18, 2017, SO_2 BART analysis for White Bluff is based on an updated baseline of 2009–2013 emissions, rather than the 2001–2003 emissions baseline EPA used in the Arkansas Regional Haze FIP to estimate the visibility improvement anticipated from SDA and wet FGD. Entergy's change in baseline emissions impacts the modeled visibility benefit anticipated from SDA, resulting in a modeled visibility benefit that is 15% to 26% lower at each unit in Entergy's updated analysis compared to the FIP. In the FIP, EPA did not evaluate the visibility improvement anticipated from DSI, enhanced DSI, and switching to low sulfur coal, but ADEQ stated it expects that the relative difference in $/dv among the control options evaluated by Entergy would be similar across both baseline periods. Further, ADEQ believes that the differences in projected visibility benefits resulting from different baseline emissions in the FIP, compared to the updated Entergy BART analysis, would not result in a change to ADEQ's ultimate SO_2 BART decision for White Bluff Units 1 and 2.

Taking into consideration the remaining useful life of White Bluff Units 1 and 2 and the resulting cost-effectiveness as well as the anticipated visibility improvement of the SO_2 control options, ADEQ concurred with Entergy's recommendation that SO_2 BART for White Bluff Units 1 and 2 is an emission limit of 0.60 lb/MMBtu based on the use of low sulfur coal.[97] All other SO_2 control options for White Bluff have an average cost-effectiveness value greater than $5,000/ton, which ADEQ stated exceeds what has typically been considered to be cost-effective for BART. Additionally, ADEQ noted that the cost-effectiveness in terms of $/dv for DSI, enhanced DSI, and SDA are approximately an order of magnitude greater than for LSC. Considering the costs and the visibility benefits of the control options, ADEQ determined that SO_2 BART for White Bluff is an emission limit of 0.60 lb/MMBtu based on the use of low sulfur coal.[98]

In support of its assertion that a 3-year compliance deadline is needed to meet this emission limit, Entergy submitted a letter to ADEQ dated April 3, 2018, explaining that it is the company's practice to project how much coal will be needed in future years and to contract for a portion of its coal supply up to 3 years in advance.[99] Entergy stated that it keeps a reserve supply of coal at White Bluff to ensure that the units can continue to operate in the event of a fuel supply disruption. Entergy finds that a 3-year compliance date is necessary for the 0.60 lb/MMBtu emission limit because the sulfur content limits of Entergy's existing coal contracts for the next 3 years exceed this emission rate. Entergy is currently under contract for coal with a sulfur content of 1.2 lb/MMBtu or less. Entergy noted that even though the coal delivered to White Bluff has lately been of lower sulfur content than required by the contract, its experience is that the sulfur content can vary widely. Entergy also stated that as of the letter dated April 3, 2018, it had already contracted for a portion of its coal supply needs for the next 3 years (through the end of the year 2020). Those contracts are for coal with a sulfur content limit ranging from 0.7 to 0.9 lb/MMBtu. Additionally, Entergy stated it cannot accurately calculate expected SO_2 emissions from blending of coals from its stockpile and new deliveries of coal because the sulfur content of the stockpile coal is not tracked. Entergy explained that this means that it cannot ensure that White Bluff will receive coal with a low enough sulfur content to ensure compliance with the 0.60 lb/MMBtu emission limit until the company has had sufficient time to negotiate new contracts and the existing coal supply has been depleted and replaced with coal that has a lower sulfur content. ADEQ agreed that a 3-year compliance date for the 0.60 lb/MMBtu emission limit based on the use of low sulfur coal is reasonable given the site-specific circumstances for White Bluff as discussed in Entergy's letter dated April 3, 2018.

With regard to the cost analysis for SO_2 controls for White Bluff, we agree that AFUDC and certain other cost items are not allowed to be considered in estimating the cost effectiveness of controls for BART purposes under the EPA Control Cost Manual, and we also acknowledge and agree with ADEQ's decision to base its evaluation of controls on Entergy's set of cost numbers that does not include the disallowed line items. Nevertheless, there is one aspect of Entergy's cost analysis that we do not agree with. Entergy's cost analysis is based on an SDA system assuming a coal sulfur content of 1.2 lb/MMBtu, which Entergy stated is based on its current coal contract sulfur limit. However, the White Bluff units have historically burned coal with a lower sulfur content. In its BART analysis, Entergy stated that the current average sulfur content of coal received at the White Bluff station is 0.57 lb SO_2/MMBtu but that the facility could receive coal with sulfur content up to 1.2 lb SO_2/MMBtu. Given that, Entergy's analysis is based on a scrubber designed to handle that sulfur load. In the Arkansas Regional Haze FIP, we noted that Entergy's SO_2 cost analysis for White Bluff, which was provided to us by Entergy for EPA's evaluation and consideration in the development of the FIP, took the approach of costing a scrubber system designed to burn coal with a sulfur content much higher than what has been historically burned,[100] an approach similar to what Entergy has done in the August 2017 BART analysis. In the FIP, we stated that we disagreed with Entergy's approach for costing of the scrubber system, and our FIP cost analysis was instead based on a dry scrubber system assuming a sulfur content of 0.68 lb/MMBtu, the maximum monthly emission rate from 2009–2013. Relying on our FIP's cost analysis for dry scrubbers for White Bluff, which was based on a scrubber system designed to burn coal having a sulfur content consistent with what the units have historically burned, and adjusting for a 7-year as opposed to a 30-year capital cost recovery period to reflect that the units will cease coal combustion by the end of 2028,[101] we estimate that the cost of dry scrubbers at White Bluff Units 1 and 2 is $4,376/ton for Unit 1 and $4,129/ton for Unit 2.[102] As noted in the SIP revision, Entergy's August 18, 2017, SO_2 BART analysis for White Bluff shows that the estimated visibility benefit of dry scrubbers for Unit 1 is 0.603 dv at Caney Creek and 0.642 dv at Upper Buffalo, and for Unit 2 is 0.574 dv at Caney Creek and 0.632 dv at Upper Buffalo.[103] Although our cost estimates for dry scrubbers are more cost-effective than estimated by Entergy, we still consider these cost numbers to be on the higher end of what has been found to be cost effective in other regional haze actions when also taking into account the level of visibility benefit of the controls. We are proposing to agree with ADEQ's conclusion that dry scrubbers are not BART for White Bluff Units 1 and 2.

We are also proposing to agree with ADEQ that the cost of compliance, in dollars per ton, for DSI and enhanced DSI is not cost effective when the

[97] Entergy evaluated an SO_2 emission rate of 0.6 lb/MMBtu based on the use of low sulfur coal in the SO_2 BART analysis for White Bluff. However, ADEQ ultimately selected 0.60 lb/MMBtu as the BART emission limit in response to comments it received during the state public comment period raising concerns that finalizing an emission limit of 0.6 lb/MMBtu could result in smaller SO_2 reductions than assumed because it is typical to round to the nearest significant digit when demonstrating compliance.

[98] The White Bluff SO_2 BART analysis submitted by Entergy and ADEQ's SIP revision both considered an SO_2 emission limit of 0.6 lb/MMBtu for the switching to low sulfur coal control option. However, in response to comments the state received during the public comment period that noted that it is typical to round to the nearest significant digit when demonstrating compliance, which could result in less emissions reductions than assumed in the analysis, ADEQ ultimately finalized an emission limit of 0.60 lb/MMBtu in the final SIP revision.

[99] The letter from Entergy, dated April 3, 2018, is found in Appendix D the Arkansas Regional Haze SO_2 and PM BART SIP Revision.

[100] 81 FR 66385; See also ''Response to Comments for the **Federal Register** Notice for the State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan,'' pages 261–263, and 345–349. The FIP Response to Comments document is found in the docket at *https://www.regulations.gov/document?D=EPA-R06-OAR-2015-0189-0187*.

[101] We are proposing to agree that it is appropriate to assume a capital cost recovery period of 7 years for scrubber controls in the BART analysis since Entergy's voluntarily proposed date for cessation of coal combustion at White Bluff Units 1 and 2 by the end of 2028 has been made enforceable through an Administrative Order. The Administrative Order can be found in the Arkansas Regional Haze SO_2 and PM BART SIP Revision.

[102] See Excel spreadsheet titled ''EPA Revised cost calcs_WB_Corrected CRF 7 years.xlsx,'' which is found in the docket for this proposed rulemaking.

[103] See Tables 4–6 and 4–7 of Entergy's August 18, 2017, White Bluff SO_2 BART analysis.

remaining useful life of White Bluff Units 1 and 2 is taken into account. We are proposing to agree that switching to low sulfur coal would result in visibility benefits from the baseline and would be very cost-effective. Therefore, we are proposing to approve the state's determination that given Entergy's enforceable commitment to cease coal combustion at White Bluff Units 1 and 2 by the end of 2028, SO_2 BART for Units 1 and 2 is an SO_2 emission limit of 0.60 lb/MMBtu based on switching to low sulfur coal. The Administrative Order for the White Bluff units also includes a requirement for the source to determine compliance with the SO_2 emission limits for Units 1 and 2 by using a continuous emission monitoring system. These BART requirements are enforceable by the state through an Administrative Order that has been adopted and incorporated in the SIP revision. We are proposing to approve in the SIP the state's Administrative Order, including the 3-year compliance date to meet the 0.60 lb/MMBtu emission limit and the requirement for Entergy to move forward with its proposed plan to cease coal combustion at White Bluff Units 1 and 2 no later than December 31, 2028.[104] We are proposing to find that Entergy's explanation that it cannot ensure that White Bluff will receive coal with a low enough sulfur content to ensure compliance with the 0.60 lb/MMBtu emission limit until the company has had sufficient time to negotiate new contracts and the existing coal supply, including the coal for which Entergy is already under contract through the year 2020, has been depleted and replaced with coal that has a lower sulfur content, is reasonable. Therefore, we are proposing to find that a 3-year compliance date for the 0.60 lb/MMBtu SO_2 BART emission limit is appropriate and reasonable. We are concurrently proposing to withdraw the FIP's SO_2 BART requirements for White Bluff Units 1 and 2, as they would be replaced by our approval of the state's SO_2 BART decision.

b. White Bluff Auxiliary Boiler BART Determinations

In determining BART for the White Bluff Auxiliary Boiler, ADEQ relied on Entergy's October 2013 BART analysis for White Bluff.[105] In the BART analysis, Entergy explained that air dispersion modeling demonstrates that the maximum visibility impact predicted from the Auxiliary Boiler is 0.036 dv, which it characterized as a very low level of visibility impact. The modeling results also show that looking at the 98th percentile visibility impacts, the greatest impact from the Auxiliary Boiler is 0.01 dv at Caney Creek.[106] Entergy reasoned that since the existing visibility impairment due to the Auxiliary Boiler is extremely low, any improvement due to controls are expected to be negligible. ADEQ further expanded on this finding by explaining that the Arkansas Regional Haze FIP found that due to the small level of baseline visibility impairment caused by the Auxiliary Boiler, the existing SO_2, NO_X, and PM emission limitations in the Entergy White Bluff permit were determined to satisfy BART for the Auxiliary Boiler. ADEQ stated that it agrees that SO_2, NO_X, and PM BART for the Auxiliary Boiler are the existing emission limits in the facility's air permit. We are proposing to find that the state's SO_2, NO_X, and PM BART decisions for the Auxiliary Boiler are appropriate. The BART Rule provides:

"Consistent with the CAA and the implementing regulations, States can adopt a more streamlined approach to making BART determinations where appropriate. Although BART determinations are based on the totality of circumstances in a given situation, such as the distance of the source from a Class I area, the type and amount of pollutant at issue, and the availability and cost of controls, it is clear that in some situations, one or more factors will clearly suggest an outcome. Thus, for example, a State need not undertake an exhaustive analysis of a source's impact on visibility resulting from relatively minor emissions of a pollutant where it is clear that controls would be costly and any improvements in visibility resulting from reductions in emissions of that pollutant would be negligible." [107]

Given the very small baseline visibility impacts from the Auxiliary Boiler, we believe it is appropriate to take a streamlined approach for determining BART in this case. Because of the very low baseline visibility impacts from the Auxiliary Boiler at each modeled Class I area, we believe that the visibility improvement that could be achieved through the installation and operation of controls would be negligible, such that the cost of those controls could not be justified. Therefore, we are proposing to approve the state's determination that the existing SO_2, NO_X, and PM emission limitations in the Entergy White Bluff permit are BART for the Auxiliary Boiler. Specifically, these emission limits are 105.2 lb/hr SO_2, 32.2 lb/hr NO_X, and 4.5 lb/hr PM. These BART requirements are enforceable by the state through an Administrative Order that has been adopted and incorporated in the SIP revision. We are proposing to approve into the SIP the state's Administrative Order, including the requirement that the White Bluff Auxiliary Boiler comply with BART as of the effective date of the Administrative Order, which is August 7, 2018.[108] We are concurrently proposing to withdraw the FIP's SO_2 and PM BART requirements for the Auxiliary Boiler, as they would be replaced by our approval of the state's BART decisions.

We also note that in the Arkansas Regional Haze NO_X SIP revision, ADEQ erroneously identified the Auxiliary Boiler as participating in CSAPR for ozone season NO_X, and the state elected to rely on participation in that trading program to satisfy the Auxiliary Boiler's NO_X BART requirements. In a final action published in the **Federal Register** on February 12, 2018, we took final action to approve this SIP revision, including reliance on CSAPR for ozone season NO_X to satisfy the Auxiliary Boiler's NO_X BART requirements.[109] Our approval of this determination for the Auxiliary Boiler was made in error. Therefore, we are proposing to withdraw our prior approval of the state's reliance on CSAPR for ozone season NO_X to satisfy the NO_X BART requirement for the Auxiliary Boiler that was included in the Arkansas Regional Haze NO_X SIP revision submitted to us on October 31, 2017. We are proposing to replace our approval of that BART finding for the Auxiliary Boiler with approval of the source specific 32.2 lb/hr NO_X BART emission limit contained in the August 8, 2018, Arkansas Regional Haze SIP revision.

C. Reasonable Progress Analysis for SO_2

In determining whether additional controls are necessary under the reasonable progress requirements and

[104] The Administrative Order can be found in the Arkansas Regional Haze SO_2 and PM BART SIP Revision.

[105] "Revised BART Five Factor Analysis White Bluff Steam Electric Station Redfield, Arkansas (AFIN 35–00110), dated October 2013, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc." This BART analysis can be found in Appendix D to the Arkansas Regional Haze SO_2 and PM BART SIP Revision.

[106] "Revised BART Five Factor Analysis White Bluff Steam Electric Station Redfield, Arkansas (AFIN 35–00110), dated October 2013, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc.," see Table 4–4.

[107] 70 FR 39116.

[108] The Administrative Order can be found in the Arkansas Regional Haze SO_2 and PM BART SIP Revision.

[109] 83 FR 5927.

thus in establishing RPGs, a state must consider the four statutory factors in section 169A(g)(1) of the CAA: (1) The costs of compliance, (2) the time necessary for compliance, (3) the energy and nonair quality environmental impacts of compliance, and (4) the remaining useful life of any existing source subject to such requirements. The Regional Haze Rule also states that in establishing the RPGs, the state must consider the uniform rate of improvement in visibility for the period covered by the implementation plan.[110] The uniform rate of visibility improvement, or uniform rate of progress (URP), needed to reach natural conditions by 2064 for each Class I area can be determined by comparing baseline conditions with natural conditions. The Regional Haze Rule provides for the use of an analytical framework that compares the rate of progress that will be achieved by a SIP (as represented by the reasonable progress goals for the end of the implementation period) to the rate of progress that if continued would result in natural conditions in 2064 (*i.e.,* the URP). When a Class I area's visibility conditions for the most impaired days are better (*i.e.,* less impaired) than the URP, the visibility conditions at the Class I areas are said to be ''below the URP line'' or ''below the glidepath.''

Consistent with section 169A(b) of the CAA, 40 CFR 51.308(d)(3) requires that states include in their SIP a long-term strategy for making reasonable progress for each Class I area within their state. This long-term strategy is the compilation of all control measures a state will use during the implementation period of the specific SIP submittal to achieve reasonable progress, and thus to meet any applicable RPGs for a particular Class I area. The long-term strategy includes control measures determined necessary pursuant to both the BART and reasonable progress analyses.

In the Arkansas Regional Haze SO_2 and PM SIP revision,[111] ADEQ noted that EPA's ''Guidance for Setting Reasonable Progress Goals under the Regional Haze Program'' [112] (EPA's RPG Guidance), provides that states have flexibility in how to take into consideration the four statutory factors. The SIP revision states that, considering this guidance, ADEQ believes that the four reasonable progress factors can be appropriately applied broadly to a group of sources state-wide rather than in a source-specific manner. However, ADEQ stated that since EPA evaluated the four factors for controls at the Independence facility in the Arkansas Regional Haze FIP as part of a source-specific analysis, it determined that application of the four factors to that particular source is also ''relevant'' in its reasonable progress analysis as a way of addressing EPA's previous analysis as reflected in the FIP. Therefore, in addition to considering a broader analysis using the four factors, ADEQ also conducted a more specific analysis for the Independence facility. The former analysis in the SIP is ''broad'' in the sense that it does not quantify costs or visibility benefits for any particular source or source category and discusses visibility benefits and costs in only qualitative terms. In the explanation of its approach, the SIP states that both analyses were completed and the results taken into consideration before the state determined whether any controls are necessary under reasonable progress.

Before presenting its broad analysis, the SIP identified the key pollutants and source categories that contribute to visibility impairment in Arkansas Class I areas. After presenting its broad analysis, the SIP presents an evaluation of which sources should be the focus of a narrow four-factor analysis and selected Independence as the only such source. The identification of the key pollutants and source categories that contribute to visibility impairment in Arkansas Class I areas, the broad reasonable progress analysis performed by ADEQ, the identification of Independence as the only source for which a narrow analysis would be performed, and ADEQ's determination regarding additional measures for Independence that are necessary for reasonable progress are discussed in the subsections that follow. We provide our assessment of each component of the reasonable progress section of the SIP revision before summarizing and assessing the next component.

1. Arkansas' Discussion of Key Pollutants and Source Category Contributions

As part of its reasonable progress analysis, ADEQ provided a discussion of the results of air quality modeling performed by the Central Regional Air Planning Association (CENRAP) in support of SIP development in the central states region for 2002 and projected 2018 emissions.[113] The CENRAP modeling included Particulate Source Apportionment Technology Tool (PSAT) with Comprehensive Air Quality model with extensions (CAMx) version 4.4, which was used to provide source apportionment by geographic regions and major source categories for pollutants that contribute to visibility impairment at each of the Class I areas in the central states region.[114] The SIP revision provided a discussion of PSAT data for sources region-wide (*i.e.,* sources both in and outside Arkansas, including sources in the continental U.S. and international sources) as well as a discussion of PSAT data for Arkansas sources. Below, we provide a summary of each set of PSAT data.

a. Region-Wide PSAT Data for Caney Creek and Upper Buffalo

Based on the region-wide PSAT data, which looked at sources both in and outside Arkansas, it was found that point sources are the primary contributor to light extinction at Arkansas' Class I areas on the 20% worst days in 2002. Region-wide point sources were found to contribute 81.04 inverse Megameters (Mm^{-1}) at Caney Creek and 77.8 Mm^{-1} at Upper Buffalo on the 20% worst days in 2002, which makes up approximately 60% of the total light extinction at each Class I area. The region-wide PSAT data showed that area stationary anthropogenic sources are the next largest source category contributor to light extinction at Arkansas Class I areas, contributing 17.81 Mm^{-1} at Caney Creek and 20.46 Mm^{-1} at Upper Buffalo, which makes up approximately 13% and 16% of the total light extinction at each Class I area, respectively. The remaining source categories (*i.e.,* natural, on-road, and non-road sources) were found to each contribute between 2 and 6% of the

[110] 40 CFR 51.308(d)(1)(i)(B).

[111] In a SIP revision submitted on October 31, 2017, Arkansas provided a reasonable progress analysis and reasonable progress determination with respect to NO_X, and we took final action to approve the analysis and determination in a final action published on February 12, 2018 (see 83 FR 5927). Thus, the Arkansas Regional Haze SO_2 and PM SIP revision addresses the reasonable progress requirements with respect to SO_2 and PM emissions.

[112] *Guidance for Setting Reasonable Progress Goals under the Regional Haze Program,* June 1, 2007, memorandum from William L. Wehrum, Acting Assistant Administrator for Air and Radiation, to EPA Regional Administrators, EPA Regions 1–10 (p. 5–1).

[113] The central states region includes Texas, Oklahoma, Louisiana, Arkansas, Kansas, Missouri, Nebraska, Iowa, Minnesota, and the tribal governments within these states.

[114] See the TSD for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation, which is found in Appendix 8.1 of the 2008 Arkansas Regional Haze SIP. The 2008 Arkansas Regional Haze SIP can be found in the docket associated with this proposed rulemaking.

total light extinction at Arkansas Class I areas.

Based on the region-wide PSAT data, Arkansas also found that sulfate (SO_4) contributed 87.05 Mm^{-1} at Caney Creek and 83.18 Mm^{-1} at Upper Buffalo on the 20% worst days in 2002, which is approximately 65% and 63% of the total modeled light extinction at each Class I area, respectively. Most of the light extinction due to SO_4 was attributed to point sources. Out of the light extinction due to SO_4, the point source category was responsible for approximately 86 to 87% of that light extinction. Point sources of SO_4 contributed 75.1 Mm^{-1} at Caney Creek and 72.17 Mm^{-1} at Upper Buffalo, or approximately 55 to 56% of the total light extinction at Arkansas Class I areas on the 20% worst days in 2002. In contrast, the other pollutant species were responsible for a much smaller proportion of the total light extinction at Arkansas' Class I areas. For example, nitrate (NO_3) contributed approximately 10%, primary organic aerosols (POA) contributed approximately 8%, elemental carbon (EC) contributed approximately 4%, crustal material (CM) contributed approximately 3 to 5%, and soil contributed approximately 1% of the total modeled light extinction at each Arkansas Class I area on the 20% worst days in 2002.

The region-wide PSAT data also showed that point sources are projected to remain the primary contributor to light extinction at Arkansas Class I areas, contributing 45.27 Mm^{-1} at Caney Creek and 43.02 Mm^{-1} at Upper Buffalo on the 20% worst days in 2018. This constitutes approximately 53% of the total light extinction at Caney Creek and 50% of the total light extinction at Upper Buffalo. Area sources are projected to continue to be the second largest contributor to light extinction, being responsible for 20% of the total light extinction at Caney Creek and 23% of the total light extinction at Upper Buffalo. The remaining source categories (*i.e.,* natural, on-road, and non-road sources) are projected to continue to contribute 5% of the total light extinction at Arkansas Class I areas on the 20% worst days in 2018. Based on the region-wide PSAT data, light extinction due to SO_4 is projected to decrease by 44% at Caney Creek and 45% at Upper Buffalo between 2002 and 2018.[115] However, SO_4 is projected to continue to be the primary driver of total light extinction at Arkansas Class I areas, with point sources continuing to be the primary source of light extinction due to SO_4. Point sources of SO_4 are projected to contribute 39.83 Mm^{-1} at Caney Creek and 37.09 Mm^{-1} at Upper Buffalo, which is between 43 and 46% of the total light extinction on the 20% worst days in 2018.

b. Arkansas PSAT Data for Caney Creek and Upper Buffalo

When looking at the PSAT data for sources within Arkansas only, the state found that the relative contribution of sources within Arkansas to total light extinction on the 20% worst days at Arkansas Class I areas is small. Species attributed to Arkansas sources contributed approximately 10% of the total light extinction on the 20% worst days in 2002 and were projected to contribute between 13 and 14% of the total light extinction on the 20% worst days in 2018. Additionally, the state found that when only the visibility impact of sources within Arkansas were considered, area sources actually had a larger impact on light extinction than point sources. Based on the Arkansas source PSAT data, area sources within Arkansas contributed 5.03 Mm^{-1} at Caney Creek on the 20% worst days in 2002, which is approximately 37% of the light extinction attributed to Arkansas sources at Caney Creek and accounts for 4% of the total light extinction at the Class I area. Based on the Arkansas source PSAT data, area sources within Arkansas contributed 6.72 Mm^{-1} at Upper Buffalo on the 20% worst days in 2002, which is approximately 50% of the light extinction attributed to Arkansas sources at Upper Buffalo and accounts for 5% of the total light extinction at the Class I area. In contrast, Arkansas point sources contributed 3.85 Mm-1 at Caney Creek on the 20% worst days in 2002, which is approximately 28% of the light extinction attributed to Arkansas sources at Caney Creek and accounts for 3% of the total light extinction at the Class I area. Arkansas point sources also contributed 3.25 Mm^{-1} at Upper Buffalo on the 20% worst days in 2002, which is approximately 24% of the light extinction attributed to Arkansas sources and accounts for 2% of the total light extinction at the Class I area. The other sources in Arkansas contributed between 7 and 14% each to light extinction attributed to Arkansas sources, accounting for approximately 1% each to the total light extinction at each Arkansas Class I area on the 20% worst days in 2002.

Based on the Arkansas source PSAT data, it was also found that SO_4 from Arkansas sources (all source categories) contributed 4.14 Mm^{-1} at Caney Creek and 3.97 Mm-1 at Upper Buffalo, which is approximately 3% of the total visibility extinction at each of the Class I areas on the 20% worst days in 2002. Out of the light extinction attributed to SO_4 from Arkansas sources, the point source category contributed approximately 67% of that light extinction at Caney Creek and Upper Buffalo. At Caney Creek, the largest contributing pollutant species next to SO_4 was POA, which contributed approximately 3.54 Mm^{-1}. At Upper Buffalo, the largest contributing pollutant species next to SO_4 was CM, which contributed approximately 3.53 Mm^{-1}. NO_3 from Arkansas sources was found to contribute 2.11 Mm^{-1} at Caney Creek and 1.07 Mm^{-1} at Upper Buffalo, which is approximately 2% and 1% of the of the total light extinction at Caney Creek and Upper Buffalo, respectively. On-road sources accounted for approximately 50% of the light extinction attributed to Arkansas sources of NO_3 at Arkansas Class I areas.

The Arkansas source PSAT data also showed that when only sources located in Arkansas are considered, area sources are projected to remain the primary contributor to light extinction at Arkansas Class I areas on the 20% worst days in 2018. Arkansas area sources are projected to contribute 4.85 Mm^{-1} at Caney Creek and 6.52 Mm^{-1} at Upper Buffalo on the 20% worst days in 2018, which is approximately 43% of light extinction attributed to Arkansas sources at Caney Creek and 54% of the light extinction attributed to Arkansas sources at Upper Buffalo. In contrast, Arkansas point sources are projected to contribute 4.05 Mm^{-1} at Caney Creek and 3.63 Mm^{-1} at Upper Buffalo on the 20% worst days in 2018. Arkansas also notes that overall, light extinction attributed to Arkansas sources of SO_4 is projected to decrease at Arkansas Class I areas on the 20% worst days in 2018, but light extinction attributed to point sources of SO_4 located in Arkansas is projected to increase by 4% at Caney Creek and 5% at Upper Buffalo.

[115] The CENRAP's 2018 modeling projections made the following regional haze control assumptions for Arkansas' point sources: (1) Installation of scrubber controls at Flint Creek Boiler No. 1 to meet the presumptive SO_2 BART limit of 0.15 lb/MMBtu; (2) installation of low NO_X burners to satisfy NO_X BART requirements at Flint Creek Boiler No. 1 and White Bluff Units 1 and 2; and (3) the shutdown of AECC Bailey Unit 1 and Entergy Lake Catherine Unit 4 by 2018. The SIP revision we are proposing to take action on requires a more stringent SO_2 emission limit for Flint Creek Boiler No. 1; requires an interim SO_2 emission limit of 0.60 lb/MMBtu and cessation of coal combustion by the end of 2028 at White Bluff Units 1 and 2; requires an SO_2 emission limit of 0.60 lb/MMBtu for Independence Units 1 and 2; does not require the installation of low NO_X burners for any of Arkansas' EGUs; and does not require shutdown of AECC Bailey Unit 1 or Entergy Lake Catherine Unit 4.

Nevertheless, Arkansas noted that the contribution to total light extinction of SO_4 from Arkansas point sources is projected to be approximately 3% of the total light extinction at each Arkansas Class I area on the 20% worst days in 2018, which is a value the state considers to be relatively small.

c. Arkansas' Conclusions Regarding Key Pollutants and Source Category Contributions

Based on an assessment of both the region-wide PSAT data and the Arkansas source PSAT data, Arkansas identified SO_4 as the key pollutant species contributing to light extinction at Caney Creek and Upper Buffalo. When looking at the region-wide PSAT data, SO_4 is the pollutant species responsible for the vast majority of the visibility impairment at Arkansas Class I areas on the 20% worst days. When looking at the Arkansas source PSAT data, SO_4 is still the pollutant species with the largest contribution to visibility impairment at Arkansas Class I areas on the 20% worst days, but its relative contribution to light extinction is not as heavily weighted as it is in the region-wide PSAT data. The primary driver of SO_4 formation at Arkansas Class I areas is emissions of SO_2 from point sources, both when looking at visibility impacts from sources region-wide and also when looking at visibility impacts only from sources in Arkansas.

Arkansas also noted that only a small proportion of total light extinction is due to NO_3 from Arkansas sources, and that this proportion has been driven by on-road sources. For example, NO_3 from Arkansas point sources contributed less than 0.5% of the total light extinction on the 20% worst days at Caney Creek and Upper Buffalo. Based on this observation, Arkansas decided not to evaluate sources of NO_3 under the four reasonable progress factors in the October 2017 Arkansas Regional Haze NO_X SIP Revision. When focusing only on sources in Arkansas, a comparison of the various source categories reveals that area sources do contribute a larger proportion of total light extinction than the other source categories. The majority of the light extinction from Arkansas area sources is due to CM and POA, but Arkansas noted that these pollutant species originate from many individual small sources and that the cost-effectiveness of these controls is therefore difficult to quantify and Arkansas therefore decided not to evaluate area sources under the four reasonable progress factors.

Since Arkansas determined that SO_4 is the key pollutant species contributing to light extinction at Caney Creek and Upper Buffalo on the 20% worst days and that the majority of light extinction due to SO_4 is attributed to point sources, it evaluated point sources emitting at least 250 tons per year (tpy) of SO_2 to determine whether their emissions and proximity to Arkansas Class I areas warrant further analysis under the four reasonable progress factors.

We agree with Arkansas that the PSAT results for Arkansas sources show that the relative contribution to light extinction of SO_4 on the 20% worst days at Arkansas Class I areas is not as great compared to the regional contribution results. However, SO_4 is still the species with the largest contribution to light extinction at Caney Creek and Upper Buffalo on the 20% worst days in both the regional data and the Arkansas source PSAT data. We agree with Arkansas' identification of SO_4 as the key species contributing to light extinction at Caney Creek and Upper Buffalo on the 20% worst days. Newer IMPROVE monitoring data that has become available after the CENRAP modeling was performed does not appear to contradict this conclusion.[116] We are also proposing to agree that the primary driver of SO_4 formation at Arkansas Class I areas is SO_2 emissions from point sources, both when looking at visibility impacts from sources region-wide and also when looking at visibility impacts only from sources in Arkansas. Arkansas' conclusions are consistent with our finding in the Arkansas Regional Haze FIP that the CENRAP's CAMx modeling shows that SO_4 from point sources is the driver of regional haze at Caney Creek and Upper Buffalo on the 20% worst days in both 2002 and 2018.[117] We also agree with Arkansas' assertion that when only sources located in Arkansas are considered, light extinction due to area sources (all pollutant species considered) is greater compared to the light extinction due to point sources at both Caney Creek and Upper Buffalo on the 20% worst days in 2002. And we agree with Arkansas that the cost of controlling many individual small area sources may be difficult to quantify, and we are therefore proposing to find that it is acceptable for Arkansas to choose not to further evaluate area sources for controls under reasonable progress in this implementation period. This is consistent with EPA's decision not to conduct a four-factor analysis of area sources under reasonable progress for this implementation period in the Arkansas Regional Haze FIP.[118] Therefore, we are proposing to find that it is appropriate for Arkansas to focus its evaluation on point sources emitting at least 250 SO_2 tpy to determine whether their emissions and proximity to Arkansas Class I areas warrant further analysis under the four reasonable progress factors.

2. Arkansas' Analysis of Reasonable Progress Factors Broadly Applicable to Arkansas Sources

In addition to the four reasonable progress factors under CAA section 169A(g)(1), ADEQ determined that visibility is also a relevant factor for consideration in its reasonable progress analysis. ADEQ's broad evaluation of the four reasonable progress factors plus visibility is summarized below.

Visibility: ADEQ explained that, since restoring natural visibility conditions in Class I areas is the central goal of the regional haze program, it considers visibility to be the necessary context within which to view whether additional controls are reasonable in the first planning period. ADEQ noted that visibility has improved dramatically in Arkansas' Class I areas since 2004, with visibility improving at a rate more rapid than needed to meet the 2018 point on the URP and Arkansas' Class I areas being on track to achieve natural visibility conditions in Arkansas Class I areas by 2064. ADEQ also noted that the observed improvement in visibility conditions has taken place even before implementation of most of the controls included in the Arkansas Regional Haze SO_2 and PM SIP revision. ADEQ stated that the observed visibility improvement at Arkansas Class I areas is the result of reductions from state and federal programs, including New Source Performance Standards for a variety of source types; vehicle emissions standards; changes in NAAQS; innovations in emissions control technologies; retirement or reconstruction of older facilities; and market-driven changes in electricity generation. ADEQ stated it anticipates

[116] IMPROVE monitoring data for Caney Creek and Upper Buffalo, as well as other Class I areas can be found at *http://views.cira.colostate.edu/fed/QueryWizard/Default.aspx.*

[117] 80 FR 18996.

[118] In the FIP we explained that the CENRAP CAMx modeling with PSAT showed that point sources are responsible for a majority of the light extinction at Arkansas Class I areas on the 20% worst days in 2002 (this is taking into account all pollutant species and sources both in and outside Arkansas). We reasoned that since other source types (*i.e.,* natural, on-road, non-road, and area) each contributed a much smaller proportion of the total light extinction at each Class I area, it was appropriate to focus only on point sources in our reasonable progress analysis for this implementation period. See 80 FR 18944 and 81 FR 66332 at 66336. See also the ''Arkansas Regional Haze FIP Response to Comments (RTC) Document,'' pages 71–99.

that the implementation of the BART controls required under the SIP revision will further keep Arkansas Class I areas on track to achieve natural visibility conditions on or before 2064.

ADEQ also stated that the visibility trajectory in Arkansas' Class I areas is a relevant factor for consideration in its reasonable progress analysis. According to ADEQ, if Arkansas Class I areas were making less progress than necessary to achieve the URP during the first planning period, then more costly controls could be warranted if found reasonable after consideration of the four statutory factors and other factors the state considers relevant. ADEQ stated that ADEQ therefore deems it reasonable to consider that Arkansas Class I areas are already below the 2018 point on the URP, in addition to considering the statutory reasonable progress factors, in evaluating whether additional controls are necessary under reasonable progress for the first implementation period.

Costs of Compliance: ADEQ pointed out that EPA's RPG Guidance provides that the cost of compliance factor "can be interpreted to encompass . . . the implication of compliance costs to the health and vitality of industries within a state." [119] Considering the visibility trends at Arkansas' Class I areas, ADEQ determined that this interpretation is appropriate to apply in this case. ADEQ believes that the cost of additional controls under reasonable progress would create a negative impact on the health and vitality of industries within the state, and that such adverse impacts would be especially great if additional SO_2 controls were imposed on the electricity sector. This is because under Arkansas law, energy companies are permitted to recover costs related to the installation of emissions controls at EGUs required under a SIP from electricity ratepayers subject to approval by the Arkansas Public Service Commission. These costs, in turn, would be allowed to be passed on to Arkansas ratepayers, including a variety of industries, in the form of increased electric rates. ADEQ believes that energy-intensive industries would be disproportionately impacted by these costs.

Time Necessary for Compliance: ADEQ noted that the time necessary for compliance varies depending on the control technology under consideration. ADEQ stated that the time necessary for compliance for SO_2 control technologies considered for BART in the SIP revision was typically 3–5 years, unless progress had already been made toward implementing those control technologies.

Energy and Non-air Quality Impacts of Compliance: ADEQ stated that the installation of additional controls, such as dry and wet scrubbers, under reasonable progress for Arkansas EGUs may have negative impacts, including temporary outages necessary to install the controls. Arkansas expects that this would temporarily disrupt the supply of electricity to the grid. Additionally, ADEQ noted that certain control technologies can result in reduced generating capacity for EGUs, which is referred to as parasitic load.

Furthermore, ADEQ noted that market trends for coal and natural gas have already resulted in the decreased dispatch of coal-fired facilities, which has in turn resulted in a decrease in overall emissions of key pollutants that impact visibility at Arkansas Class I areas. ADEQ cited to data from the Energy Information Administration showing that the trend of decreased net electricity generation from coal and increased net electricity generation from natural gas and renewable energy is expected to continue for the remainder of the 2008–2018 implementation period, and well beyond.

Remaining Useful Life of Potentially Affected Sources: ADEQ pointed out that the EPA RPG Guidance provides that this factor is generally best treated as one element of the overall cost analysis. ADEQ noted that if the remaining useful life for a given facility is less than the typical amortization period for new control equipment, the annualized cost increases and the controls become less cost effective. Additionally, ADEQ pointed out that the cost of controls may result in a company making an economic decision to discontinue operations, thus truncating the remaining useful life of a source.

3. Identification of Potential Sources for Evaluation of SO_2 Controls Under Reasonable Progress

In identifying which sources to evaluate for SO_2 controls in its reasonable progress analysis, Arkansas compiled a list of all point sources that emitted at least 250 SO_2 tpy as reported to the EPA emissions Inventory System (EIS) in any given year between 2002 and 2015. For sources that participate in EPA's Acid Rain Program, Arkansas obtained SO_2 emissions data for 2015 using the Air Markets Program Data tool. Arkansas then narrowed down the list to only those sources that emitted at least 250 tpy averaged over the most recent 3-year period for which data is available. Arkansas identified 11 sources that met this criterion (see Table 11).

TABLE 11—POINT SOURCES IN ARKANSAS WITH SO_2 EMISSIONS GREATER THAN 250 TPY

Facility	Most recent 3-year period	Average SO_2 emissions (tpy)
Entergy White Bluff *	2014–2016	24,346
Entergy Independence	2014–2016	22,531
SWEPCO Flint Creek Power Plant *	2014–2016	5,350
Plum Point Energy Station Unit 1	2014–2016	2,759
FutureFuel Chemical Company	2013–2015	2,837
Domtar A.W. LLC, Ashdown Mill *	2013–2015	1,553
Evergreen Packaging—Pine Bluff	2013–2015	986
Albemarle Corporation—South Plant	2013–2015	1,382
SWEPCO John W. Turk Jr. Power Plant	2014–2016	908
Ash Grove Cement Company/Foreman Cement Plant	2013–2015	369
Nucor—Yamato Steel Company	2013–2015	301

*These facilities are subject to BART requirements, and the state therefore did not further consider these sources for additional controls under reasonable progress.

[119] *Guidance for Setting Reasonable Progress Goals under the Regional Haze Program,* June 1, 2007, memorandum from William L. Wehrum, Acting Assistant Administrator for Air and Radiation, to EPA Regional Administrators, EPA Regions 1–10 (p. 5–1).

Arkansas explained that, since White Bluff, Flint Creek, and Domtar are subject to BART and the BART analyses conducted to determine BART control requirements are based on an assessment of many of the same factors that must be evaluated in determining whether additional controls are needed under the reasonable progress provisions and thus in establishing the RPGs, no additional controls under reasonable progress are necessary for these sources in the first implementation period. For the remaining sources on the list, Arkansas calculated the total average actual emission rate (Q) in SO_2 tpy over the most recent 3-year period and determined the distance (D) in kilometers of each source to its closest Class I area (see Table 12). Arkansas used a ''Q divided by D'' (Q/D) value of 10 as a threshold for identifying sources to further evaluate for reasonable progress controls. Arkansas explained that it selected this value as a threshold based on guidance contained in the BART Guidelines and also noted that this is consistent with the approach used in other regional haze actions.

TABLE 12—Q/D VALUES FOR LARGE SO_2 POINT SOURCES IN ARKANSAS

Facility	Q/D value	
	Upper buffalo	Caney creek
Entergy Independence	126	81
Plum Point Energy Station Unit 1	9	7
FutureFuel Chemical Company	17	10
Evergreen Packaging—Pine Bluff	4	5
Albemarle Corporation—South Plant	5	9
SWEPCO John W. Turk Jr. Power Plant	4	11
Ash Grove Cement Company/Foreman Cement Plant	1	5
Nucor—Yamato Steel Company	1	1

As shown in Table 12, Arkansas found that only three sources had a maximum Q/D value greater than or equal to 10: Entergy Independence, FutureFuel Chemical Company, and John W. Turk Jr. Power Plant. Arkansas noted that Entergy Independence is the second largest point source of SO_2 emissions in Arkansas, with average 2014–2016 emissions of 22,531 SO_2 tpy. In comparison, the FutureFuel Chemical Company and the John W. Turk Jr. Power Plant had much lower SO_2 emissions. FutureFuel Chemical Company had average 2013–2015 SO_2 emissions of 2,837 tpy, while the John W. Turk Jr. Power Plant had average 2014–2016 SO_2 emissions of 908 tpy. Arkansas noted that SO_2 emissions from the FutureFuel Chemical Company and the John W. Turk Jr. Power Plant are approximately an order of magnitude lower than emissions from Entergy Independence. In addition, Arkansas noted that the FutureFuel Chemical Company was previously identified as a BART eligible source, but was determined to be not subject to BART in the 2008 Arkansas Regional Haze SIP based on CALPUFF modeling performed in the development of that SIP. Therefore, ADEQ did not find it necessary to further evaluate controls under reasonable progress for this facility for this implementation period. The John W. Turk Jr. Power Plant, which began operation in 2012, has implemented best available control technology, which Arkansas noted is more stringent than BART. Therefore, ADEQ stated that it does not anticipate that more stringent controls would be available and/or reasonable for this facility in the first implementation period. Arkansas ultimately determined that since the Independence facility is a source not subject to BART and because it was required by the Arkansas Regional Haze FIP to install controls under reasonable progress, this particular source warrants further consideration and evaluation under the four reasonable progress factors.

We are proposing to find that Arkansas' overall method of identifying sources for potential further evaluation under the four reasonable progress factors is appropriate. We find that Arkansas' approach of narrowing down the list of sources to further evaluate under reasonable progress to only those sources that emitted at least 250 SO_2 tpy averaged over the most recent 3-year period for which data is available is reasonable. We agree with Arkansas that since White Bluff and Flint Creek are subject to BART and are addressed under this SIP revision, the BART analyses conducted to determine BART control requirements for these sources and the determinations adopted and incorporated by the state in this SIP revision are adequate to eliminate these sources from further consideration of additional controls under the reasonable progress requirements for the first implementation period. The EPA RPG Guidance explains that the BART analysis is based, in part, on an assessment of many of the same factors that must be addressed in establishing the RPGs, and therefore it is reasonable to conclude that any control requirements imposed in the BART determination also satisfy the RPG-related requirements for source review in the first implementation period.[120] The guidance provides that it is reasonable to conclude that any control requirements imposed in the BART determination also satisfy the RPG-related requirements for source review in the first RPG planning period.[121] The same rationale applies for the Domtar Ashdown Mill, although the August 8, 2018 SIP revision does not address the BART requirements for Domtar, which will remain satisfied by the FIP and the 2008 Arkansas Regional Haze SIP. Based on the consideration of the BART factors and resulting determinations in that FIP and the 2008 Arkansas Regional Haze SIP, it is reasonable for ADEQ to conclude that nothing further is needed to address emissions from Domtar under the requirement for reasonable progress analysis at this time. If ADEQ chooses to submit a SIP revision to address BART requirements for Domtar Power Boilers No. 1 and No. 2, we will evaluate that SIP submittal, including whether it also sufficiently addresses the reasonable progress requirements for Domtar for the first implementation period.

We are proposing to find that Arkansas' use of a Q/D value of 10 as a threshold for identifying sources to further evaluate for reasonable progress controls is reasonable and appropriate. We agree with Arkansas, that the FutureFuel Chemical Company was

[120] *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program,* June 1, 2007, memorandum from William L. Wehrum, Acting Assistant Administrator for Air and Radiation, to EPA Regional Administrators, EPA Regions 1–10 (pp. 4–2, 4–3, and 5–1).

[121] *Id.*

found by the state to be not subject to BART in the 2008 Arkansas Regional Haze SIP, which is a determination that was approved by EPA in our March 2012 final action on the SIP.[122] The FutureFuel Chemical Company and the John W. Turk Jr. Power Plant are the fifth and ninth largest SO_2 point sources in Arkansas, based on average annual emissions from the most recent 3-year period.[123] In comparison to the SO_2 emissions from the 3 largest SO_2 point sources in Arkansas, emissions from these two facilities are relatively small.[124] Taking into consideration the significantly lower 3-year average SO_2 emissions from the FutureFuel Chemical Company and the John W. Turk Jr. Power Plant in comparison to the Independence Power Plant and considering that the John W. Turk Jr. Power Plant operates best available control technology, we are proposing to find that it is reasonable and appropriate for Arkansas to not further evaluate these sources for controls under reasonable progress for this planning period. We also consider it appropriate and reasonable for Arkansas to decide to conduct an analysis of the reasonable progress factors for the Independence facility. In particular, we consider it appropriate to evaluate the Independence facility because it is the second highest point source of SO_2 emissions in Arkansas, accounting for approximately 36% of the SO_2 point source emissions in Arkansas; its Q/D values as determined by ADEQ are high (see Table 12), especially when compared to other Arkansas point sources; and it is a source not subject to BART. Therefore, we are proposing to agree with Arkansas' decision to evaluate the four reasonable progress factors for the Independence facility.

4. Arkansas' Reasonable Progress Analysis for Independence Units 1 and 2

As noted above, ADEQ determined that application of the four factors to that specific source is also ''relevant'' in its reasonable progress analysis as a way of addressing EPA's previous analysis.

a. Arkansas' Evaluation of the Reasonable Progress Factors for SO_2 for Entergy Independence Units 1 and 2

Section 169(A)(g)(1) of the CAA requires states to evaluate the costs 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 sources, when determining reasonable progress. In its evaluation of the four reasonable progress factors for the Independence facility, Arkansas relied on information provided by Entergy for the Independence facility in the evaluation of low sulfur coal and dry scrubbers. Arkansas also relied on data developed by EPA in support of the Arkansas Regional Haze FIP in the evaluation of wet scrubbers and dry scrubbers. The Entergy Independence Power Plant is a coal-fired electric generating station with two identical 900 MW boilers. The 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. The layout and boiler units at this facility are similar to those at Entergy White Bluff, but since the units at Independence were installed in 1983 (9 years after the installation of the White Bluff units), Independence Units 1 and 2 are not BART eligible.

There is currently no SO_2 control equipment in use at Units 1 and 2. Arkansas noted that the Independence units are subject to a prevention of significant deterioration (PSD) emission limit of 0.93 lb/MMBtu. Arkansas also noted that market trends for coal and natural gas have resulted in decreased dispatch of the Independence units, which has resulted in reduced emissions from the facility. The available SO_2 control technology options considered in Arkansas' analysis are as follows: Switching to coal with a lower sulfur content, dry FGD, and wet FGD, all of which Arkansas identified as being technically feasible. Switching to coal with a sulfur content of 0.6 lb/MMBtu (referred to herein as low sulfur coal) is expected to result in a 4 to 6% reduction in SO_2 emissions from 2009–2013 levels. Dry FGD systems typically have SO_2 control efficiencies ranging from 60 to 95% control, while wet FGD is typically capable of achieving 80 to 95% control of SO_2 emissions.

Degree of Improvement in Visibility: Although the degree of visibility improvement is not one of the four statutory factors that must be evaluated in a reasonable progress analysis, as noted above, Arkansas chose to consider visibility improvement since the ultimate goal of any controls under reasonable progress is to achieve visibility improvements. For switching to low sulfur coal, Entergy submitted CALPUFF modeling that estimated the visibility benefit of switching to low sulfur coal for Independence Units 1 and 2. This modeling showed that switching to low sulfur coal is anticipated to result in visibility improvements of 0.112 dv at Caney Creek and 0.236 dv at Upper Buffalo. For dry scrubbers, Arkansas relied on the visibility improvement estimates from the modeling conducted by EPA for the Arkansas Regional Haze FIP. Arkansas noted that the installation of dry FGD at Independence Units 1 and 2 is anticipated to result in visibility improvements of 1.096 dv at Caney Creek and 1.178 dv at Upper Buffalo.[125] As discussed above, Arkansas also estimated that the cost in terms of dollars per deciview of dry FGD at Independence Units 1 and 2 ranges from $63,580,175/dv to $71,672,197/dv at each of the four affected Class I areas (see Table 13).

Remaining Useful Life: Since there are no state- or federally-enforceable limitations on continued operations at the Independence facility, Arkansas' cost analysis for SO_2 controls assumed a 30-year amortization period for dry

[122] The 2008 Arkansas Regional Haze SIP showed that FutureFuel Chemical Company had a maximum visibility impact (*i.e.,* 1st high value) of 0.711 dv at Hercules Glades. EPA found that closer inspection of the visibility modeling results revealed that only this single day out of the 3 years modeled exceeded the 0.5 dv threshold used by ADEQ to determine if a source is subject to BART. Since only one day modeled above the threshold, EPA found in its final action on the 2008 Arkansas Regional Haze SIP that it is unlikely that a refined modeling approach using updated meteorological data, which would allow the use of the 98th percentile visibility impact instead of the max visibility impact, would show impacts above the 0.5 dv threshold. Therefore, EPA concluded in our March 2012 final action on the 2008 Arkansas Regional Haze SIP that it was not necessary to further evaluate controls under reasonable progress for the FutureFuel Chemical Company in the first implementation period.

[123] See the Arkansas Regional Haze SO_2 and PM SIP Revision, Table 11.

[124] The three largest SO_2 point sources in Arkansas, based on average annual emissions from the most recent 3-year period, are the Entergy White Bluff Plant, Entergy Independence Plant, and SWEPCO Flint Creek Plant (see Table 11 of the Arkansas Regional Haze SO_2 and PM SIP Revision). The Entergy White Bluff Plant and the SWEPCO Flint Creek Plant are subject to BART and controls for these facilities are already addressed in the SIP revision based on ADEQ's consideration of the 5 BART factors.

[125] We note that in the SIP revision, ADEQ relied on EPA's visibility modeling from the FIP for dry scrubbers at the Independence facility. In that visibility modeling, EPA modeled two baseline scenarios: (1) The BASE case emission rates for NO_X and SO_2 were from the maximum actual 24-hour emissions during the 2001–2003 period; and (2) the BASE 2 case emission rates for SO_2 were based on the maximum actual 24-hour emissions during the 2001–2003 period and the NO_X emissions were based on the maximum 24-hour emissions during the 2011–2013 period. Entergy's CALPUFF modeling for low sulfur coal at the Independence facility was based on a 2011–2013 baseline period for modeled emission rates. While Entergy's baseline for low sulfur coal differed from the two baselines modeled by EPA for dry scrubbers, ADEQ stated they do not expect that the difference would substantially impact the comparison of the visibility benefits among controls evaluated.

FGD and wet FGD.[126] However, Arkansas acknowledged Entergy's intention, as stated in comments to Arkansas regarding the draft SIP, to cease coal combustion at Independence Units 1 and 2 by the end of 2030. In addition, Arkansas noted that market pressures may also impact continued operations at the Independence facility, including changes in dispatch and economic decisions concerning the continued viability of the units. Therefore, Arkansas recognized that the amortization period of controls may end up being less than the 30 years assumed in Arkansas' cost analysis, potentially resulting in the controls being less cost effective than estimated in the analysis.

Costs of Compliance: In considering the costs of compliance, Arkansas noted that switching to low sulfur coal has no associated capital costs, but there would be a cost associated with guaranteeing that the sulfur content remains below 0.6 lb/MBtu. Arkansas stated it calculated cost estimates for switching to low sulfur coal using information provided by Entergy regarding cost premiums for low sulfur coal, U.S. Energy Information Administration fuel consumption data, and EPA Air Markets Program Data. Arkansas estimated that the annualized operation and maintenance costs of switching to low sulfur coal is $1.6 million for Unit 1 and $1.7 million for Unit 2.[127] Arkansas estimated that the cost effectiveness of switching to low sulfur coal is approximately $2,437/ton for Unit 1 and $2,345/ton for Unit 2.

In contrast to switching to low sulfur coal, the installation of dry FGD and wet FGD is expected to require a large capital investment. Entergy provided Arkansas with Independence-specific cost estimates for dry scrubbers for use in Arkansas' cost analysis. Entergy estimated total capital costs of dry scrubbers at Independence to be $491,893,500 per unit based on ''actual costs'' and $355,391,500 per unit based on costs allowed under EPA's Control Cost Manual. Entergy annualized the capital cost for both sets of numbers assuming a 9-year amortization period, based on Entergy's plans to cease coal combustion at Independence by the end of 2030. Additionally, Entergy based its calculations of SO_2 emissions reductions based on a 2009–2013 baseline. In the SIP revision, ADEQ based its evaluation of the cost of dry scrubbers on the set of capital costs that reflect the costs allowed under EPA's Control Cost Manual, and also assumed a 30-year amortization period in its calculation of the cost-effectiveness of dry scrubbers. Based on these assumptions, Arkansas estimated that the cost-effectiveness of dry scrubbers is $2,970/ton for Unit 1 and $2,742/ton for Unit 2.

Since Entergy did not provide Independence-specific cost estimates for wet scrubbers for Arkansas to base its cost analysis on, Arkansas relied on the cost estimates for Independence developed by EPA in the Arkansas Regional Haze FIP.[128] Based on a 30-year amortization period, our FIP estimated wet FGD to cost $3,706/ton at Unit 1 and $3,416/ton at Unit 2. Arkansas noted that in the Arkansas Regional Haze FIP, EPA eliminated wet scrubbers due to the high incremental cost-effectiveness but small incremental visibility benefit of wet scrubbers compared to dry scrubbers. Therefore, consistent with EPA's action in the FIP, ADEQ found that wet FGD did not warrant further consideration in its analysis.

In addition to considering cost-effectiveness calculations in the cost analysis, Arkansas found that other cost-related factors were of relevance in its evaluation of the reasonable progress factors for the Independence facility. This includes total capital costs, cost to Arkansas communities, and the cost in terms of dollar per dv improvement in visibility anticipated from the control options evaluated ($/dv). Arkansas considered the capital costs of dry scrubbers and wet scrubbers to be high, even though the costs in terms of $/ton of SO_2 emissions reduced for both dry and wet scrubbers (assuming a 30-year remaining useful life) are within a range that has been found to be cost effective in other regional haze actions. In addition, acknowledging Entergy's anticipated cessation of coal combustion at the Independence facility, although it is not state- or federally-enforceable, Arkansas noted that assuming a 9-year remaining useful life would likely result in scrubber controls no longer being cost-effective. In light of this, Arkansas considered it important to take into account the capital cost of controls along with the cost-effectiveness in terms of dollars per ton of emissions reduced. Arkansas also noted that these costs would be passed on to Arkansas ratepayers. Finally, Arkansas also took into account that the $/dv improvement in visibility for dry scrubbers is a little over 2 times higher than for low sulfur coal at Caney Creek and between 5 and 6 times higher at Upper Buffalo and the 2 Missouri Class I areas (see Table 13). Arkansas noted that consideration of the cost in terms of $/dv improvement demonstrates a greater disparity in costs among the control options compared to consideration of the cost in terms of $/ton reduced. Arkansas concluded that all the control options considered would result in millions of dollars spent to achieve what it considers to be little visibility benefit.

TABLE 13—COST OF SO_2 CONTROLS ($/dv) FOR INDEPENDENCE UNITS 1 AND 2

SO_2 control option	Class I Area			
	Caney Creek	Upper Buffalo	Hercules Glades	Mingo
Low Sulfur Coal	$29,469,780	$10,929,190	$13,985,658	$12,179,393
Dry FGD	68,337,085	63,580,175	70,925,611	71,672,197

Time Necessary for Compliance: Arkansas explained that the typical time necessary for compliance for dry FGD and wet FGD is 5 years. Considering the time left on existing coal supply contracts between Entergy and its coal

[126] As explained above, Entergy annualized the capital cost of controls on the Independence facility assuming a 9-year amortization period, based on Entergy's plans for ceasing coal combustion at Independence by the end of 2030. However, given that Entergy's plans to cease coal combustion by the end of 2030 are not state or federally-enforceable, ADEQ re-calculated the cost-effectiveness of controls by annualizing the capital cost of controls assuming a 30-year amortization period.

[127] ADEQ calculated annualized operation and maintenance costs of switching to low sulfur coal by multiplying average annual fuel consumption in tons for the years 2009–2013 by the $0.50/ton cost premium Entergy was quoted by its coal supplier, per Entergy's August 18, 2017, SO_2 BART analysis for White Bluff. ADEQ obtained annual fuel consumption data for the years 2009–2013 from U.S. Energy Information Administration Form EIA–923.

[128] See 80 FR 18992–18993. See also the Arkansas Regional Haze SO_2 and PM SIP Revision, Appendix F.

supplier, the time required to burn through current fuel stocks, and the time needed to build a stockpile of low sulfur coal to assure against potential fuel supply disruptions, Entergy informed Arkansas that the time necessary to comply with an SO_2 emission limit based on low sulfur coal is estimated to be 3 years.

Energy and Non-air Quality Environmental Impacts of Compliance: Arkansas noted that dry FGD utilizes lime slurry to remove SO_2 from flue gas and that in the process, particulate matter is generated that must be controlled through the use of a baghouse or ESP. Once collected, the waste material is disposed of through landfilling. Arkansas noted that the costs associated with control of particulate matter and additional power requirements were factored into the cost estimates used in its analysis. Arkansas determined that Entergy has not indicated unusual circumstances that would create greater problems than experienced in other cases where dry FGD has been utilized to meet regional haze requirements. Arkansas also noted that switching to low sulfur coal is not anticipated to result in any adverse energy or non-air environmental impacts.

b. Arkansas' Determination Regarding Reasonable Progress Requirements for Independence

Based on its evaluation of the reasonable progress factors for the Independence facility, ADEQ arrived at the conclusion that no additional controls are necessary for reasonable progress during the first implementation period. According to ADEQ, the controls it evaluated would cost millions of dollars annually, which would be passed on to Arkansas ratepayers, for what ADEQ considers to be little visibility benefit when Arkansas' Class I areas are already making more progress than the URP.

Although ADEQ concluded that none of the controls evaluated for the Independence facility are necessary for achieving reasonable progress in the first planning period, ADEQ acknowledged Entergy's intention to switch to low sulfur coal at Independence Units 1 and 2 within the next 3 years. ADEQ noted that this measure would strengthen the SIP and result in some visibility benefit at Arkansas' Class I areas, while having no associated capital costs. According to ADEQ, the lack of any capital costs will provide Entergy with flexibility regarding the company's planned cessation of coal combustion at the Independence facility by the end of 2030. Therefore, Entergy's commitment to switch to low sulfur coal at Independence Units 1 and 2 has now been made enforceable by ADEQ as part of the long-term strategy for this implementation period, through an Administrative Order that has been adopted and incorporated in the SIP revision. The Administrative Order requires Independence Units 1 and 2 to meet an SO_2 emission limit of 0.60 lb/MMBtu no later than 3 years from the effective date of the Administrative Order, which is August 7, 2018.[129]

5. Arkansas' Determination Regarding Additional Controls Necessary Under Reasonable Progress and Revised RPGs

After consideration of the statutory reasonable progress factors, along with an evaluation of the monitored trajectory of visibility impairment during the first implementation period, particulate source apportionment data, and SO_2 emissions relative to proximity to Arkansas Class I areas, Arkansas determined that no additional controls beyond BART and other Clean Air Act programs are necessary under the reasonable progress provisions for the first implementation period. Based on its analysis of the reasonable progress factors in the context of both the analysis of a group of sources as well as the source-specific analysis that applied the reasonable progress factors specifically to the Independence facility, Arkansas determined that all the evaluated controls would result in the expenditure of millions of dollars annually for what the state considers to be little visibility benefit. In addition, the costs of any control requirements would be passed on to Arkansas citizens and businesses through electricity rate increases. Arkansas deems that these costs are not warranted under reasonable progress given that Arkansas Class I areas are well below their respective 2018 URPs. Arkansas believes that its reasonable progress determination is consistent with EPA's decision to establish a 64-year lifespan for the regional haze program, which is broken down into several 10-year implementation periods. Arkansas stated that the way the regional haze program was set up allows for a fresh look at the changing landscape of sources that impact visibility and potential controls every 10 years. Arkansas noted that the EPA Reasonable Progress Guidance provides that it is reasonable for states to defer reductions to later planning periods in order to maintain a consistent glidepath toward the long-term goal of natural visibility conditions. Therefore, Arkansas determined that no SO_2 or PM controls beyond BART are necessary for reasonable progress during the first implementation period.

To reflect the control measures required in the Arkansas Regional Haze SO_2 and PM SIP revision and the Arkansas Regional Haze NO_X SIP revision, which was approved by EPA in a prior action,[130] Arkansas revised the RPGs for the 20% worst days for Caney Creek and Upper Buffalo that it had previously established in the 2008 Arkansas Regional Haze SIP. Arkansas did not revise its RPGs for the 20% best days included in the 2008 Arkansas Regional Haze SIP. In order to provide RPGs for the 20% worst days that account for emissions reductions from its SIP revisions, Arkansas utilized a method that is based on a scaling of modeled light extinction components in proportion to emissions changes anticipated from SIP controls for which compliance is required on or before December 31, 2018. Arkansas noted that this is the same method utilized by EPA to revise the RPGs in the Arkansas Regional Haze FIP. Arkansas scaled CENRAP's CAMx 2018 projection of light extinction components for SO_4 and NO_3 in proportion to the SIP revisions' emission reductions for SO_2 and NO_X from the CENRAP modeled 2018 emissions. Arkansas decided to use the most recent 3 years of data (2014–2016) as opposed to EPA's method in the Arkansas FIP, which involved using the 5 most recent years of data (2009–2013) with the exclusion of the minimum and maximum values. Arkansas explained that this was done to ensure that recent changes in dispatch at Arkansas EGUs were captured. Arkansas' revised RPGs for Caney Creek and Upper Buffalo are presented in Table 14.

TABLE 14—ARKANSAS' REVISED 2018 RPGS FOR CANEY CREEK AND UPPER BUFFALO

Class I area	2018 RPG 20% worst days (dv)
Caney Creek	22.47
Upper Buffalo	22.51

6. EPA's Evaluation and Conclusions on Arkansas' Reasonable Progress Analysis and Revised RPGs

As noted above, as part of its reasonable progress analysis, Arkansas

[129] The Administrative Order can be found in the Arkansas Regional Haze SO_2 and PM BART SIP Revision.

[130] 83 FR 5927.

conducted both a broad source analysis and a source-specific analysis that evaluated the four statutory factors for the Independence facility. The former analysis was ''broad'' in the sense that it did not quantify costs or visibility benefits for any particular source or source category, and discussed anticipated visibility benefits and costs in only general terms. We agree that an approach that involves a broad analysis of groups of sources or source categories may be appropriate in certain cases, as provided by EPA's RPG Guidance. However, we believe that the broad analysis of a group of sources provided by ADEQ does not clearly identify what sources or controls were evaluated in the state's weighing of the costs and other statutory factors. While informative, we find that the state's broad analysis of a group of sources was not a determinative component of the state's reasonable progress analysis given that the state's determination was also informed by an evaluation of large point sources individually to identify sources for potential further evaluation under the four reasonable progress factors and by a more narrow and focused analysis conducted for those sources identified, specifically the Independence facility, which included consideration of various control options and weighing of costs and the other statutory factors.

We are proposing to find that the reasonable progress requirements under section 51.308(d)(1) have been fully addressed for the first regional haze planning period. Specifically, we are proposing to find that the following components of Arkansas' analysis satisfy the reasonable progress requirements: Arkansas' discussion of the key pollutants and source categories that contribute to visibility impairment in Arkansas Class I areas based on the CENRAP's source apportionment modeling; the identification of a group of large SO_2 point sources for potential consideration of controls under reasonable progress and the eventual narrowing down of the list to the Independence facility; [131] and the evaluation of the four reasonable progress factors for SO_2 controls on the Independence facility.

We are proposing to agree with Arkansas' cost analysis for dry scrubbers and switching to low sulfur coal for Independence Units 1 and 2, and with the state's decision to assume a 30-year capital cost recovery period in the cost analysis. It is appropriate to assume a 30-year capital cost recovery period in the cost analysis since Entergy's plans to cease coal combustion at the Independence facility are not state or federally-enforceable. We also agree with Arkansas' estimates of the cost of dry scrubbers, and note that the state's estimates of the cost effectiveness of dry scrubbers for Units 1 and 2 are very similar to the cost effectiveness estimates we developed in the Arkansas Regional Haze FIP.[132]

Since the White Bluff and Independence facilities are sister facilities with nearly identical units and comparable levels of annual SO_2 emissions, and since both DSI and enhanced DSI were evaluated in the BART analysis for White Bluff Units 1 and 2, we believe it would be appropriate to consider these controls in the four-factor analysis for the Independence facility as well. However, neither the SIP revision nor Entergy's four factor analysis for controls on the Independence facility considered DSI or enhanced DSI as control options. Therefore, relying on Entergy's estimates of the capital costs and annual operation and maintenance costs for DSI and enhanced DSI for White Bluff Units 1 and 2 from Entergy's August 18, 2017, White Bluff BART analysis,[133] and assuming a 30-year equipment life, we estimate the cost-effectiveness of DSI at the Independence facility to be approximately $4,963/$SO_2$ ton removed for Unit 1 and $4,593/$SO_2$ ton removed for Unit 2.[134] We estimate the cost-effectiveness of enhanced DSI to be approximately $4,951/$SO_2$ ton removed for Unit 1 and $4,581/$SO_2$ ton removed for Unit 2.[135] Based on our cost estimates for DSI, we find that DSI is less cost-effective than dry scrubbers or wet scrubbers for Independence Units 1 and 2.[136] Although the anticipated visibility benefits of DSI at the Independence facility were not modeled, we expect that these would be less than that for dry scrubbers or wet scrubbers, since DSI and enhanced DSI typically have a lower SO_2 removal efficiency than scrubber controls. Further, we expect that the installation and operation of DSI or enhanced DSI would likely present the same potential issues discussed by Entergy in its SO_2 BART analysis for White Bluff. Specifically, Entergy stated that before DSI technology could be selected as BART for White Bluff, a demonstration test would need to be performed to confirm its feasibility, achievable performance, and balance of plant impacts (brown plume formation, ash handling modifications, landfill/leachate considerations, and impact to mercury control). In addition, Entergy claimed that DSI has not yet been demonstrated on units comparable to those at White Bluff. Because of the similarities between the White Bluff and Independence facilities, we expect that these same potential issues related to the installation and operation of DSI or enhanced DSI would also apply to the Independence facility. In light of all this, we expect that even if ADEQ had considered DSI and enhanced DSI in its reasonable progress analysis for the Independence facility, it likely would not have changed the state's final determination on reasonable progress. Therefore, under these particular circumstances, we do not consider the omission of consideration of DSI and enhanced DSI as control options for SO_2 at the Independence facility an impediment to approving the reasonable progress analysis.

In its reasonable progress analysis for the Independence facility, the statutory factor that appears to have been the most significant in Arkansas' reasonable progress determination is the cost of compliance, as well as visibility, which the state deemed to be a relevant factor for consideration in its analysis. Arkansas discussed its concerns regarding the significant capital cost of scrubber controls, noted that the evaluation of the $/dv metric demonstrated a greater difference in cost between dry FGD and low sulfur coal compared to the $/ton metric, and ultimately concluded that all the controls it evaluated would cost millions of dollars for what it considers to be little visibility benefit. We believe

[131] As explained elsewhere in this notice, ADEQ relied on the fact that a FIP is in place to satisfy the BART requirements for the Domtar Ashdown Mill to find that nothing further is needed to address the reasonable progress requirements with regard to this source for the first implementation period. EPA is proposing to agree that it is appropriate to rely on the FIP in this manner.

[132] Compare Arkansas' estimates of the cost effectiveness of dry scrubbers for the Independence facility ($2,970/ton for Unit 1 and $2,742/ton for Unit 2) with EPA's estimates of the cost effectiveness of dry scrubbers for the facility ($2,853/ton for Unit 1 and $2,634/ton for Unit 2). See 81 FR 66352.

[133] We are relying on Entergy's ''adjusted costs,'' which reflect Entergy's exclusion of line items not allowed under EPA's Control Cost Manual. See ''Entergy Updated BART Five-Factor Analysis for Units 1 and 2,'' dated August 18, 2017, Table 4–4. This analysis is found under Appendix D of the Arkansas Regional Haze SO_2 and PM SIP revision.

[134] See the file titled ''EPA Cost Calcs_DSI and enhanced DSI_Independence.xlsx,'' which can be found in the docket for this proposed rulemaking.

[135] *Id.*

[136] This is based on a comparison of our cost estimates for DSI with Entergy's cost estimates for dry scrubbers and the FIP's cost estimates for wet scrubbers for Independence Units 1 and 2. Entergy's cost estimates for dry scrubbers and the FIP's cost estimates for wet scrubbers for Independence Units 1 and 2 are discussed earlier in this notice under Section II.C.4.a.

that Arkansas' weighing of the four statutory factors and other factors it deemed relevant in its reasonable progress analysis for the Independence facility was reasonable. Considering the state's concerns about the high capital costs and high $/dv of the evaluated controls and given that the state is requiring Independence Units 1 and 2 to switch to low sulfur coal within 3 years under the long-term strategy, which is expected to reduce SO_2 emissions and result in visibility improvements at Arkansas' Class I areas, it is not unreasonable for Arkansas to conclude that SO_2 controls under the reasonable progress requirements are not necessary for the Independence facility in the first implementation period. We are proposing to fully approve Arkansas' focused reasonable progress analysis, which applied the four statutory factors directly to the Independence facility, and its determination that no additional controls under the reasonable progress requirements are necessary to achieve reasonable progress for the first implementation period. Our proposed approval is based on the following: (1) The state's discussion of the key pollutants and source categories that contribute to visibility impairment in Arkansas' Class I areas per the CENRAP's source apportionment modeling; (2) the state's identification of a group of large SO_2 point sources in Arkansas for potential evaluation of controls under reasonable progress; (3) the state's rationale for narrowing down its list of potential sources to evaluate under the reasonable progress requirements;[137] and (4) the state's evaluation and reasonable weighing of the four statutory factors along with consideration of the visibility benefits of controls for the Independence facility.

We are also proposing to find that the method used by Arkansas to estimate revised 2018 RPGs for the 20% worst days for Caney Creek and Upper Buffalo is appropriate. We agree with Arkansas that this is the same method utilized by us to revise the RPGs in the Arkansas Regional Haze FIP. We are also proposing to find that Arkansas' use of the most recent 3 years of data (2014–2016) as opposed to use of the 5 most recent years of data (2009–2013) with the exclusion of the minimum and maximum values, as we used in the Arkansas FIP, is appropriate because it reflects updated data and we also agree with Arkansas that it will ensure that recent changes in dispatch at Arkansas EGUs are captured. Therefore, we are proposing to agree with Arkansas' revised 2018 RPGs of 22.47 dv for Caney Creek and 22.51 dv for Upper Buffalo.

As discussed elsewhere in this proposed rulemaking, BART controls for Domtar Power Boilers No. 1 and 2 are not addressed in the Arkansas Regional Haze SO_2 and PM SIP Revision, and we are not proposing to withdraw the FIP's BART emission limits for the facility at this time. If and when ADEQ submits a SIP revision to address BART requirements for Domtar Power Boilers No. 1 and No. 2, we will evaluate any conclusions ADEQ has drawn in that submission with respect to the need to conduct a reasonable progress analysis for Domtar. As long as the BART requirements for Domtar continue to be addressed by the measures in the FIP, however, we propose to agree with ADEQ's conclusion that nothing further is needed to satisfy the reasonable progress requirements for the first implementation period. With respect to the RPGs for Arkansas' Class I areas, if and when ADEQ submits a SIP revision addressing Domtar, we will assess that future SIP revision to determine if changes are needed based on any differences between the SIP-based measures and the measures currently contained in the FIP.

D. Long-Term Strategy

Section 169A(b) of the CAA and 40 CFR 51.308(d)(3) require that states include in their SIPs a 10 to 15-year strategy, referred to as the long-term strategy, for making reasonable progress for each Class I area within their state. This long-term strategy is the compilation of all control measures a state will use during the implementation period of the specific SIP submittal to meet any applicable RPGs for a particular Class I area. The long-term strategy must include ''enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals'' for all Class I areas within, or affected by emissions from, the state.[138]

Section 51.308(d)(3)(v) requires that a state consider certain elements in developing its long-term strategy for each Class I area. These considerations are the following: (1) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment (RAVI); (2) measures to mitigate the impacts of construction activities; (3) emissions limitations and schedules for compliance to achieve the reasonable progress goal; (4) source retirement and replacement schedules; (5) smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the state for these purposes; (6) enforceability of emissions limitations and control measures; and (7) the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy. Since states are required to consider emissions limitations and schedules of compliance to achieve the RPGs for each Class I area, the BART emission limits that are in a state's regional haze SIP are elements of the state's long-term strategy for each Class I area. In our March 12, 2012, final action on the 2008 Arkansas Regional Haze SIP, since we disapproved a portion of Arkansas' BART determinations for Arkansas' two Class I areas, we also disapproved the corresponding emissions limitations and schedules of compliance elements of the state's long-term strategy, while approving remaining elements under section 51.308(d)(3)(v).

As discussed above, the state is making enforceable Entergy's commitment to switch Independence Units 1 and 2 to low sulfur coal and comply with an SO_2 emission limit of 0.60 lb/MMBtu within 3 years as part of the long-term strategy. We are proposing to approve Arkansas' decision to make enforceable the 0.60 lb/MMBtu SO_2 emission limit for Independence Units 1 and 2 as part of the long-term strategy and we are also proposing to approve the other components of the long-term strategy addressed by the August 8, 2018 SIP revision. We are proposing to find that Arkansas' long-term strategy is approved with respect to sources other than the Domtar Ashdown Mill. Because we disapproved the majority of ADEQ's 2008 BART determinations for the Domtar facility and promulgated a FIP to satisfy these requirements, the corresponding components of the long-term strategy for Domtar are also currently satisfied by the FIP. No further action by ADEQ is required at this time; the Domtar-related components will remain covered by the FIP and the approved portion of the 2008 Arkansas Regional Haze SIP unless and until EPA

[137] As explained above, part of ADEQ's basis for determining the sources for which to conduct a narrow reasonable progress analysis was that certain sources were subject to BART analyses and determinations in the first implementation period. For the Domtar facility in particular, the state relied on the fact that a FIP is in place to address the BART requirements. We propose to agree that this is an appropriate basis on which find that nothing further is needed for reasonable progress at this source. If, in the future, Arkansas submits a further SIP revision addressing the Domtar Ashdown Mill, EPA will evaluate whether the analysis and determinations therein satisfy the reasonable progress requirements as well as BART.

[138] 40 CFR 51.308(d)(3).

has received and approved a SIP revision containing the required analyses and determinations for this facility.

E. Required Consultation

The Regional Haze Rule requires states to provide the designated Federal Land Managers (FLMs) with an opportunity for consultation at least 60 days prior to holding any public hearing on a SIP revision for regional haze for the first implementation period. Arkansas sent letters to the FLMs on October 27, 2017, providing notification of the proposed SIP revision and providing electronic access to the draft SIP revision and related documents.[139] ADEQ also engaged in telephone communications with the FLMs and considered and addressed comments submitted by the FLMs on the proposed SIP revision.[140]

The Regional Haze Rule at section 51.308(d)(3)(i) also provides that if a state has emissions that are reasonably anticipated to contribute to visibility impairment in a Class I area located in another state, the state must consult with the other state(s) in order to develop coordinated emission management strategies. Since Missouri has two Class I areas impacted by Arkansas sources, Arkansas sent a letter to the Missouri Department of Natural Resources (MDNR) on October 27, 2017, providing notification of the proposed SIP revision and providing electronic access to the draft SIP revision and related documents.[141] Missouri did not provide comments to Arkansas on the proposed SIP revision.

We are proposing to find that Arkansas provided an opportunity for consultation to the FLMs and to Missouri on the proposed SIP revision, as required under section 51.308(i)(2) and 51.308(d)(3)(i). We are also proposing to find that Arkansas has appropriately considered and provided written responses to comments from the FLMs in the final SIP submission. Therefore, we are proposing to find that Arkansas has satisfied the consultation requirements under sections 51.308(i)(2) and 51.308(d)(3)(i).

F. Interstate Visibility Transport Under Section 110(a)(2)(D)(i)(II)

The SIP revision also includes a discussion on interstate visibility transport. Specifically, the SIP revision discusses the impacts of Arkansas sources on Missouri's Class I areas, as well as the most recent IMPROVE monitoring data for Missouri's Class I areas. The SIP revision concludes that Missouri is on track to achieve its visibility goals, that the visibility progress observed indicates that sources in Arkansas are not interfering with the achievement of Missouri's RPGs for Hercules Glades and Mingo, and that no additional controls on sources within Arkansas are necessary to ensure that other states' visibility goals for their Class I areas are met. We are deferring proposing action on the interstate visibility transport portion of the SIP revision until a future proposed rulemaking.

G. Clean Air Act Section 110(l)

Section 110(l) of the CAA states that "[t]he Administrator shall not approve a revision of a plan if the revision would interfere with any applicable requirement concerning attainment and reasonable further progress or any other applicable requirement of this chapter." We believe an approval of the Arkansas Regional Haze SO_2 and PM SIP revision and concurrent withdrawal of the corresponding parts of the FIP, as proposed, will meet the Clean Air Act's 110(1) provisions concerning attainment and maintenance. No areas in Arkansas are currently designated nonattainment for any NAAQS pollutants. As all areas in Arkansas are attaining the NAAQS with current emissions levels, further reductions from current emission levels because of compliance with the emission limits contained in this SIP revision will not interfere with attainment or maintenance. The SIP will result in emission reductions beyond the status quo.

Additionally, we do not believe an approval of the Arkansas Regional Haze SO_2 and PM SIP revision and concurrent withdrawal of the corresponding parts of the FIP would interfere with the CAA requirements for BART or reasonable progress because our proposed approval of the SIP revision is supported by our evaluation of the state's conclusions and our rationale explaining why we are proposing to find that the BART and reasonable progress requirements under the CAA are met, as discussed under sections II.B and II.C of this notice. With respect to BART requirements, the SIP would replace federal determinations regarding SO_2 and PM control requirements for EGUs in Arkansas with the state's own determinations. We do note that the majority of the state's SO_2 and PM BART determinations in the SIP revision are essentially identical to the BART determinations contained in the Arkansas Regional Haze FIP. The only exception to this is White Bluff Units 1 and 2, for which the FIP requires an SO_2 emission limit of 0.06 lb/MMBtu with a 5-year compliance date, based on the installation of dry scrubbers. The Arkansas Regional Haze SO_2 and PM SIP revision does not require the SO_2 emission limit of 0.06 lb/MMBtu, but it does require that Entergy move forward with its announced plans to cease coal combustion at White Bluff Units 1 and 2 by the end of 2028 and to meet an interim SO_2 emission limit of 0.60 lb/MMBtu prior to ceasing coal combustion. Once the units cease coal combustion, SO_2 emissions from White Bluff Units 1 and 2 are expected to significantly decrease. Therefore, we expect that the BART controls contained in the SIP revision are comparable to the BART controls required under the FIP in the long term. More importantly, our proposed approval of the SIP revision does not violate CAA section 110(l) with respect to BART requirements because the state's BART decisions in the SIP revision, which we are proposing to approve, are adequately supported by BART five factor analyses that have been adopted and incorporated into the SIP revision.

With respect to reasonable progress, we are proposing to approve Arkansas' determination that no additional controls under the reasonable progress requirements are necessary to achieve reasonable progress for the first implementation period. In contrast to the Arkansas Regional Haze FIP, the Arkansas Regional Haze SO_2 and PM SIP revision does not require an SO_2 emission limit of 0.06 lb/MMBtu with a 5-year compliance date for Independence Units 1 and 2 based on the installation of dry scrubber controls under the reasonable progress requirements. Nevertheless, as discussed in Section II.C of this notice, we are proposing to find that the reasonable progress requirements under section 51.308(d)(1) have been fully addressed for the first implementation period, based on Arkansas' discussion of the key pollutants and source categories that contribute to visibility impairment in Arkansas' Class I areas per the CENRAP's source apportionment modeling; its identification of a group of large SO_2 point sources in Arkansas for potential evaluation of controls under reasonable progress; the state's rationale for narrowing down its list of potential sources to evaluate under the reasonable progress requirements; and its analysis

[139] See Arkansas Regional Haze SO_2 and PM SIP revision, Tab E.

[140] ADEQ included copies of correspondence with the FLM's, included comments received from the FLMs in Tab E of the Arkansas Regional Haze SO_2 and PM SIP revision.

[141] See Arkansas Regional Haze SO_2 and PM SIP revision, Tab E.

with reasonable weighing of the four statutory factors along with consideration of the visibility benefits of controls for the Independence facility. Therefore, even though the SIP revision would allow for an increase in SO_2 emissions from the Independence facility compared to the FIP, our proposed approval of the SIP revision and concurrent withdrawal of the corresponding parts of the FIP does not violate CAA section 110(l) with respect to reasonable progress because we are proposing to find that Arkansas has provided a reasoned basis to support its determination that the scrubber controls are not needed for reasonable progress.

III. Proposed Action

A. Arkansas Regional Haze SIP Revision

The EPA is proposing to approve the following revisions to the Arkansas Regional Haze SIP submitted to EPA on August 8, 2018: The SO_2 and PM BART requirements for the AECC Bailey Plant Unit 1; the SO_2 and PM BART requirements for the AECC McClellan Plant Unit 1; the SO_2 BART requirements for Flint Creek Plant Boiler No. 1; the SO_2 BART requirements for the White Bluff Plant Units 1 and 2; the SO_2, NO_X, and PM BART requirements for the White Bluff Auxiliary Boiler; and the prohibition on burning of fuel oil at Lake Catherine Unit 4 until SO_2 and PM BART determinations for the fuel oil firing scenario are approved into the SIP by EPA. These BART requirements have now been made enforceable by the state through Administrative Orders that have been adopted and incorporated in the SIP revision. We are proposing to approve these Administrative Orders as source-specific BART revisions to the SIP. The BART requirements and associated Administrative Orders are listed under Table 15 below. We are proposing to withdraw our February 12, 2018,[142] approval of Arkansas' reliance on participation in the CSAPR ozone season NO_X trading program to satisfy the NO_X BART requirement for the White Bluff Auxiliary Boiler given that Arkansas erroneously identified the Auxiliary Boiler as participating in CSAPR for ozone season NO_X. We are proposing to replace our prior approval of Arkansas' determination for the White Bluff Auxiliary Boiler with our proposed approval of the source specific NO_X BART emission limit contained in the August 8, 2018, SIP revision. We are proposing to approve ADEQ's revised identification of the 6A Boiler at the Georgia-Pacific Crossett Mill as BART-eligible and the additional information and technical analysis presented in the SIP revision in support of the determination that the Georgia-Pacific Crossett Mill 6A and 9A Boilers are not subject to BART.

We are also proposing to find that the reasonable progress requirements under section 51.308(d)(1) have been fully addressed for the first implementation period. Specifically, we are proposing to approve the state's focused reasonable progress analysis and the reasonable progress determination that no additional SO_2 controls at Independence Units 1 and 2 or any other Arkansas sources are necessary under reasonable progress for the first implementation period. We are also proposing to agree with the state's revised RPGs for Arkansas' Class I areas. We are basing our proposed approval of the reasonable progress provisions and revised RPGs on the state's discussion of the key pollutants and source categories that contribute to visibility impairment in Arkansas' Class I areas per the CENRAP's source apportionment modeling; the state's identification of a group of large SO_2 point sources in Arkansas for potential evaluation of controls under reasonable progress; the state's rationale for narrowing down its list of potential sources to evaluate under the reasonable progress requirements; and the state's evaluation and reasonable weighing of the four statutory factors along with consideration of the visibility benefits of controls for the Independence facility. The August 8, 2018, SIP revision does not address BART and associated long-term strategy requirements for the Domtar Ashdown Mill Power Boilers No. 1 and 2, and we are not proposing to withdraw the FIP's BART emission limits for the facility at this time. If and when ADEQ submits a SIP revision to address BART requirements for Domtar Power Boilers No. 1 and No. 2, we will evaluate any conclusions ADEQ has drawn in that submission with respect to the need to conduct a reasonable progress analysis for Domtar. As long as the BART requirements for Domtar continue to be addressed by the measures in the FIP, however, we propose to agree with ADEQ's conclusion that nothing further is needed to satisfy the reasonable progress requirements for the first implementation period. With respect to the RPGs for Arkansas' Class I areas, if and when ADEQ submits a SIP revision addressing Domtar, we will assess that future SIP revision to determine if changes are needed based on any differences between the SIP-based measures and the measures currently contained in the FIP.

We are proposing to approve the components of the long-term strategy under section 51.308(d)(3) addressed by the August 8, 2018, SIP revision, including the BART measures contained in the SIP revision and the SO_2 emission limit of 0.60 lb/MMBtu for Independence Units 1 and 2 based on the use of low sulfur coal. These requirements for Independence Units 1 and 2 have now been made enforceable by the state through an Administrative Order that has been adopted and incorporated in the SIP revision. We are proposing to approve this Administrative Order as a source-specific revision to the SIP. The SO_2 emission limit and associated Administrative Order for the Independence facility are listed under Table 16 below. We are proposing to find that Arkansas' long-term strategy is approved with respect to sources other than the Domtar Ashdown Mill. We are also proposing to find that Arkansas has provided an opportunity for consultation to the FLMs and to Missouri on the proposed SIP revision, as required under section 51.308(i)(2) and 51.308(d)(3)(i). The BART emission limits we are proposing to approve are presented in Table 15; the SO_2 emission limits under the long-term strategy and associated Administrative Order we are proposing to approve for the Independence facility are presented in Table 16; and Arkansas' revised 2018 RPGs are presented in Table 17.

[142] 83 FR 5927.

TABLE 15—SIP REVISION BART EMISSION LIMITS AND ADMINISTRATIVE ORDERS PROPOSED FOR APPROVAL

Subject-to-BART source	SIP revision SO_2 BART emission limits	SIP revision PM BART emission limits	SIP revision NO_X BART emission limits	Administrative order
AECC Bailey Unit 1	0.5% limit on sulfur content of fuel combusted*.	0.5% limit on sulfur content of fuel combusted*.	Already SIP-approved	Administrative Order LIS No. 18–071.
AECC McClellan Unit 1	0.5% limit on sulfur content of fuel combusted*.	0.5% limit on sulfur content of fuel combusted*.	Already SIP-approved	Administrative Order LIS No. 18–071.
AEP Flint Creek Boiler No. 1.	0.06 lb/MMBtu*	Already SIP-approved	Already SIP-approved	Administrative Order LIS No. 18–072.
Entergy Lake Catherine Unit 4 (fuel oil firing scenario).	Unit is allowed to burn only natural gas*.	Unit is allowed to burn only natural gas*.	Already SIP-approved	Administrative Order LIS No. 18–073.
Entergy White Bluff Unit 1	0.60 lb/MMBtu (Interim emission limit with a 3-year compliance date and cessation of coal combustion by end of 2028).	Already SIP-approved	Already SIP-approved	Administrative Order LIS No. 18–073.
Entergy White Bluff Unit 2	0.60 lb/MMBtu (Interim emission limit with a 3-year compliance date and cessation of coal combustion by end of 2028).	Already SIP-approved	Already SIP-approved	Administrative Order LIS No. 18–073.
Entergy White Bluff Auxiliary Boiler.	105.2 lb/hr*	4.5 lb/hr*	32.2 lb/hr*	Administrative Order LIS No. 18–073.

* This BART emission limit required by the SIP revision is the same as what was required under the Arkansas Regional Haze FIP.

TABLE 16—SIP REVISION EMISSION LIMITS UNDER REASONABLE PROGRESS AND ADMINISTRATIVE ORDERS PROPOSED FOR APPROVAL

Source	SIP revision SO_2 emission limits	Administrative order
Entergy Independence Unit 1	0.60 lb/MMBtu	Administrative Order LIS No. 18–073.
Entergy Independence Unit 2	0.60 lb/MMBtu	Administrative Order LIS No. 18–073.

TABLE 17—ARKANSAS' REVISED 2018 RPGS

Class I area	2018 RPG 20% worst days (dv)
Caney Creek	22.47
Upper Buffalo	22.51

B. Partial FIP Withdrawal

We are proposing to withdraw those portions of the Arkansas Regional Haze FIP at 40 CFR 52.173 that impose SO_2 and PM BART requirements on Bailey Unit 1; SO_2 and PM BART requirements on McClellan Unit 1; SO_2 BART requirements on Flint Creek Boiler No. 1; the provisions concerning BART for the fuel oil firing scenario for Lake Catherine Unit 4; SO_2 BART requirements for White Bluff Units 1 and 2; SO_2 and PM BART requirements for the White Bluff Auxiliary Boiler; and the SO_2 emission limits under reasonable progress for Independence Units 1 and 2. We are proposing that these portions of the FIP will be replaced by the portion of the Arkansas Regional Haze SO_2 and PM SIP revision that we are proposing to approve in this action. Since we are proposing to withdraw certain portions of the FIP, we are also proposing to redesignate the FIP by revising the numbering of certain paragraphs under section 40 CFR 52.173. Our proposed redesignation of the numbering of these paragraphs is non-substantive and does not mean we are reopening these parts for public comment in this proposed rulemaking.

C. Clean Air Act Section 110(l)

We are proposing to find that an approval of a portion of the Arkansas Regional Haze SO_2 and PM SIP revision and concurrent withdrawal of the corresponding parts of the FIP, as proposed, will meet the Clean Air Act's 110(1) provisions.

IV. Incorporation by Reference

In this action, we are proposing to include in a final rule regulatory text that includes incorporation by reference. In accordance with the requirements of 1 CFR 51.5, we are proposing to incorporate by reference revisions to the Arkansas source specific requirements as described in the Proposed Action section above. We have made, and will continue to make, these documents generally available electronically through *www.regulations.gov* and in hard copy at the EPA Region 6 office (please contact Dayana Medina, 214–665–7241, *medina.dayana@epa.gov* for more information).

V. Statutory and Executive Order Reviews

Under the CAA, the Administrator is required to approve a SIP submission that complies with the provisions of the Act and applicable Federal regulations. 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, the EPA's role is to approve state choices, provided that they meet the criteria of the CAA. Accordingly, this action merely proposes to approve state law as meeting Federal requirements and does not impose additional requirements beyond those imposed by state law. For that reason, this action:

- Is not a "significant regulatory action" subject to review by the Office of Management and Budget under Executive Orders 12866 (58 FR 51735, October 4, 1993) and 13563 (76 FR 3821, January 21, 2011);
- Is not an Executive Order 13771 (82 FR 9339, February 2, 2017) regulatory action because SIP approvals are exempted under Executive Order 12866;

• Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);

• Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);

• Does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);

• Does not have Federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);

• Is not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);

• Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001);

• Is not subject to requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because this action does not involve technical standards; and

• Does not provide EPA with the discretionary authority to address, as appropriate, disproportionate human health or environmental effects, using practicable and legally permissible methods, under Executive Order 12898 (59 FR 7629, February 16, 1994).

In addition, the SIP is not approved to apply on any Indian reservation land or in any other area where EPA or an Indian tribe has demonstrated that a tribe has jurisdiction. In those areas of Indian country, the proposed rule does not have tribal implications and will not impose substantial direct costs on tribal governments or preempt tribal law as specified by Executive Order 13175 (65 FR 67249, November 9, 2000).

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Best available retrofit technology, Incorporation by reference, Intergovernmental relations, Ozone, Particulate matter, regional haze, Reporting and recordkeeping requirements, Sulfur dioxide, Visibility.

Dated: November 21, 2018.

David Gray,

Acting Regional Administrator, Region 6.

Title 40, chapter I, of the Code of Federal Regulations is proposed to be amended as follows:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

■ 1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart E—Arkansas

■ 2. In § 52.170:

■ a. In paragraph (d), the table titled ''EPA-Approved Arkansas Source-Specific Requirements'' is amended by revising the heading ''Permit No.'' to ''Permit or Order No.'' and adding the entries ''Arkansas Electric Cooperative Corporation Carl E. Bailey Plant'', ''Arkansas Electric Cooperative Corporation John L. McClellan'', ''Entergy Arkansas, Inc. Lake Catherine Plant'', ''Entergy Arkansas, Inc. White Bluff Plant'', and ''Entergy Arkansas, Inc. Independence Plant''.

■ b. In paragraph (e), the third table titled ''EPA-Approved Non-Regulatory Provisions and Quasi-Regulatory Measures in the Arkansas SIP'' is amended by adding the entry ''Arkansas Regional Haze SO_2 and PM SIP Revision'' at the end of the third table.

The revision and additions read as follows:

§ 52.170 Identification of plan.

* * * * *

(d) * * *

(e) * * *

* * * * *

EPA-APPROVED ARKANSAS SOURCE-SPECIFIC REQUIREMENTS

Name of source	Permit or order no.	State approval/ effective date	EPA approval date	Comments
Arkansas Electric Cooperative Corporation Carl E. Bailey Plant.	Administrative Order LIS No. 18–071.	8/7/2018	[Date of publication of the final rule in the **Federal Register**] [**Federal Register** citation of the final rule].	Unit 1.
Arkansas Electric Cooperative Corporation John L. McClellan.	Administrative Order LIS No. 18–072.	8/7/2018	[Date of publication of the final rule in the **Federal Register**] [**Federal Register** citation of the final rule].	Unit 1.
Entergy Arkansas, Inc. Lake Catherine Plant.	Administrative Order LIS No. 18–073.	8/7/2018	[Date of publication of the final rule in the **Federal Register**] [**Federal Register** citation of the final rule].	Unit 4.
Entergy Arkansas, Inc. White Bluff Plant.	Administrative Order LIS No. 18–073.	8/7/2018	[Date of publication of the final rule in the **Federal Register**] [**Federal Register** citation of the final rule].	Units 1, 2, and the Auxiliary Boiler.
Entergy Arkansas, Inc. Independence Plant.	Administrative Order LIS No. 18–073.	8/7/2018	[Date of publication of the final rule in the **Federal Register**] [**Federal Register** citation of the final rule].	Units 1 and 2.

EPA-APPROVED NON-REGULATORY PROVISIONS AND QUASI-REGULATORY MEASURES IN THE ARKANSAS SIP

Name of SIP provision	Applicable geographic or nonattainment area	State submittal/ effective date	EPA approval date	Explanation
*	*	* *	*	* *
Arkansas Regional Haze SO_2 and PM SIP Revision.	Statewide	August 8, 2018	[Date of publication of the final rule in the **Federal Register**] [**Federal Register** citation of the final rule].	Regional Haze SIP submittal addressing SO_2 and PM BART requirements for Arkansas EGUs, NO_X BART requirement for the White Bluff Auxiliary Boiler, and reasonable progress requirements for SO_2 for the first implementation period.

■ 3. Section 52.173 is amended by:
■ a. Revising the introductory text of paragraph (c) and paragraph (c)(1);
■ b. In paragraph (c)(2) revising the definition "*Boiler-operating-day*";
■ c. Removing paragraphs (c)(3) through (12), and (22) through (24);
■ d. Redesignating paragraphs (c)(13) through (21) as paragraphs (c)(3) through (11);
■ e. Redesignating paragraphs (c)(25) through (27) as paragraphs (c)(12) through (14);
■ f. Revising newly redesignated paragraphs (c)(4), (c)(5),(c)(7), (c)(8), (c)(10), (c)(11), and (c)(12);
■ g. Adding paragraphs (g) and (h).

The revisions and additions read as follows:

§ 52.173 Visibility protection.

* * * * *

(c) *Federal implementation plan for regional haze.* Requirements for Domtar Ashdown Paper Mill Power Boilers No. 1 and 2 affecting visibility.

(1) *Applicability.* The provisions of this section shall apply to each owner or operator, or successive owners or operators of the sources designated as Domtar Ashdown Paper Mill Power Boilers No. 1 and 2.

(2) * * *

Boiler-operating-day means a 24-hr period between 6 a.m. and 6 a.m. the following day during which any fuel is fed into and/or combusted at any time in the power boiler.

* * * * *

(4) *Compliance dates for Domtar Ashdown Mill Power Boiler No. 1.* The owner or operator of the boiler must comply with the SO_2 and NO_X emission limits listed in paragraph (c)(3) of this section by November 28, 2016.

(5) *Compliance determination and reporting and recordkeeping requirements for Domtar Ashdown Paper Mill Power Boiler No. 1.* (i)(A) SO_2 emissions resulting from combustion of fuel oil shall be determined by assuming that the SO_2 content of the fuel delivered to the fuel inlet of the combustion chamber is equal to the SO_2 being emitted at the stack. The owner or operator must maintain records of the sulfur content by weight of each fuel oil shipment, where a "shipment" is considered delivery of the entire amount of each order of fuel purchased. Fuel sampling and analysis may be performed by the owner or operator, an outside laboratory, or a fuel supplier. All records pertaining to the sampling of each shipment of fuel oil, including the results of the sulfur content analysis, must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives. SO_2 emissions resulting from combustion of bark shall be determined by using the following site-specific curve equation, which accounts for the SO_2 scrubbing capabilities of bark combustion: $Y= 0.4005 * X - 0.2645$

Where:

Y = pounds of sulfur emitted per ton of dry fuel feed to the boiler.

X = pounds of sulfur input per ton of dry bark.

(B) The owner or operator must confirm the site-specific curve equation through stack testing. By October 27, 2017, the owner or operator must provide a report to EPA showing confirmation of the site specific-curve equation accuracy. Records of the quantity of fuel input to the boiler for each fuel type for each day must be compiled no later than 15 days after the end of the month and must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives. Each boiler-operating-day of the 30-day rolling average for the boiler must be determined by adding together the pounds of SO_2 from that boiler-operating-day and the preceding 29 boiler-operating-days and dividing the total pounds of SO_2 by the sum of the total number of boiler operating days (*i.e.,* 30). The result shall be the 30 boiler-operating-day rolling average in terms of lb/day emissions of SO_2. Records of the total SO_2 emitted for each day must be compiled no later than 15 days after the end of the month and must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives. Records of the 30 boiler-operating-day rolling averages for SO_2 as described in this paragraph (c)(5)(i) must be maintained by the owner or operator for each boiler-operating-day and made available upon request to EPA and ADEQ representatives.

(ii) If the air permit is revised such that Power Boiler No. 1 is permitted to burn only pipeline quality natural gas, this is sufficient to demonstrate that the boiler is complying with the SO_2 emission limit under paragraph (c)(3) of this section. The compliance determination requirements and the reporting and recordkeeping requirements under paragraph (c)(5)(i) of this section would not apply and confirmation of the accuracy of the site-specific curve equation under paragraph (c)(5)(i)(B) of this section through stack testing would not be required so long as Power Boiler No. 1 is only permitted to burn pipeline quality natural gas.

(iii) To demonstrate compliance with the NO_X emission limit under paragraph (c)(3) of this section, the owner or operator shall conduct stack testing using EPA Reference Method 7E, found at 40 CFR part 60, Appendix A, once every 5 years, beginning 1 year from the effective date of our final rule, which corresponds to October 27, 2017. Records and reports pertaining to the stack testing must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives.

(iv) If the air permit is revised such that Power Boiler No. 1 is permitted to burn only pipeline quality natural gas, the owner or operator may demonstrate compliance with the NO_X emission limit under paragraph (c)(3) of this section by calculating NO_X emissions using fuel usage records and the applicable NO_X emission factor under AP–42, Compilation of Air Pollutant Emission Factors, section 1.4, Table 1.4–1. Records of the quantity of natural gas input to the boiler for each day must be compiled no later than 15 days after the end of the month and must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives. Records of the calculation of NO_X emissions for each day must be compiled no later than 15 days after the end of the month and must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives. Each boiler-operating-day of the 30-day rolling average for the boiler must be determined by adding together the pounds of NO_X from that day and the preceding 29 boiler-operating-days and dividing the total pounds of NO_X by the sum of the total number of hours during the same 30 boiler-operating-day period. The result shall be the 30 boiler-operating-day rolling average in terms of lb/hr emissions of NO_X. Records of the 30 boiler-operating-day rolling average for NO_X must be maintained by the owner or operator for each boiler-operating-day and made available upon request to EPA and ADEQ representatives. Under these circumstances, the compliance determination requirements and the reporting and recordkeeping requirements under paragraph (c)(5)(iii) of this section would not apply.

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(7) *SO_2 and NO_X Compliance dates for Domtar Ashdown Mill Power Boiler No. 2.* The owner or operator of the boiler must comply with the SO_2 and NO_X emission limits listed in paragraph (c)(6) of this section by October 27, 2021.

(8) *SO_2 and NO_X Compliance determination and reporting and recordkeeping requirements for Domtar Ashdown Mill Power Boiler No. 2.* (i) NO_X and SO_2 emissions for each day shall be determined by summing the hourly emissions measured in pounds of NO_X or pounds of SO_2. Each boiler-operating-day of the 30-day rolling average for the boiler shall be determined by adding together the pounds of NO_X or SO_2 from that day and the preceding 29 boiler-operating-days and dividing the total pounds of NO_X or SO_2 by the sum of the total number of hours during the same 30 boiler-operating-day period. The result shall be the 30 boiler-operating-day rolling average in terms of lb/hr emissions of NO_X or SO_2. If a valid NO_X pounds per hour or SO_2 pounds per hour is not available for any hour for the boiler, that NO_X pounds per hour shall not be used in the calculation of the 30 boiler-operating-day rolling average for NO_X. For each day, records of the total SO_2 and NO_X emitted for that day by the boiler must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives. Records of the 30 boiler-operating-day rolling average for SO_2 and NO_X for the boiler as described in this paragraph (c)(8)(i) must be maintained by the owner or operator for each boiler-operating-day and made available upon request to EPA and ADEQ representatives.

(ii) The owner or operator shall continue to maintain and operate a CEMS for SO_2 and NO_X on the boiler listed in paragraph (c)(6) of this section in accordance with 40 CFR 60.8 and 60.13(e), (f), and (h), and appendix B of 40 CFR part 60. The owner or operator shall comply with the quality assurance procedures for CEMS found in 40 CFR part 60. Compliance with the emission limits for SO_2 and NO_X shall be determined by using data from a CEMS.

(iii) Continuous emissions monitoring shall apply during all periods of operation of the boiler listed in paragraph (c)(6) of this section, including periods of startup, shutdown, and malfunction, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments. Continuous monitoring systems for measuring SO_2 and NO_X and diluent gas shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Hourly averages shall be computed using at least one data point in each fifteen-minute quadrant of an hour. Notwithstanding this requirement, an hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant in an hour) if data are unavailable as a result of performance of calibration, quality assurance, preventive maintenance activities, or backups of data from data acquisition and handling system, and recertification events. When valid SO_2 or NO_X pounds per hour emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks, or zero and span adjustments, emission data must be obtained by using other monitoring systems approved by the EPA to provide emission data for a minimum of 18 hours in each 24-hour period and at least 22 out of 30 successive boiler operating days.

(iv) If the air permit is revised such that Power Boiler No. 2 is permitted to burn only pipeline quality natural gas, this is sufficient to demonstrate that the boiler is complying with the SO_2 emission limit under paragraph (c)(6) of this section. Under these circumstances, the compliance determination requirements under paragraphs (c)(8)(i) through (iii) of this section would not apply to the SO_2 emission limit listed in paragraph (c)(6) of this section.

(v) If the air permit is revised such that Power Boiler No. 2 is permitted to burn only pipeline quality natural gas and the operation of the CEMS is not required under other applicable requirements, the owner or operator may demonstrate compliance with the NO_X emission limit under paragraph (c)(6) of this section by calculating NO_X emissions using fuel usage records and the applicable NO_X emission factor under AP–42, Compilation of Air Pollutant Emission Factors, section 1.4, Table 1.4–1. Records of the quantity of natural gas input to the boiler for each day must be compiled no later than 15 days after the end of the month and must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives. Records of the calculation of NO_X emissions for each day must be compiled no later than 15 days after the end of the month and must be maintained and made available upon request to EPA and ADEQ representatives. Each boiler-operating-day of the 30-day rolling average for the boiler must be determined by adding together the pounds of NO_X from that day and the preceding 29 boiler-operating-days and dividing the total pounds of NO_X by the sum of the total number of hours during the same 30 boiler-operating-day period. The result shall be the 30 boiler-operating-day rolling average in terms of lb/hr emissions of NO_X. Records of the 30 boiler-operating-day rolling average for NO_X must be maintained by the owner or operator for each boiler-operating-day and made available upon request to EPA and ADEQ representatives. Under these circumstances, the compliance determination requirements under paragraphs (c)(8)(i) through (iii) of this section would not apply to the NO_X emission limit.

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(10) *PM compliance dates for Domtar Ashdown Mill Power Boiler No. 2.* The owner or operator of the boiler must comply with the PM BART requirement listed in paragraph (c)(9) of this section by November 28, 2016.

(11) Alternative *PM Compliance Determination for Domtar Ashdown Paper Mill Power Boiler No.2.* If the air permit is revised such that Power Boiler No. 2 is permitted to burn only pipeline quality natural gas, this is sufficient to demonstrate that the boiler is complying

with the PM BART requirement under paragraph (c)(9) of this section.

(12) *Reporting and recordkeeping requirements.* Unless otherwise stated, all requests, reports, submittals, notifications, and other communications to the Regional Administrator required under paragraph (c) of this section shall be submitted, unless instructed otherwise, to the Director, Multimedia Division, U.S. Environmental Protection Agency, Region 6, to the attention of Mail Code: 6MM, at 1445 Ross Avenue, Suite 1200, Dallas, Texas 75202–2733. For each unit subject to the emissions limitation under paragraph (c) of this section, the owner or operator shall comply with the following requirements, unless otherwise specified:

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(g) *Measures addressing best available retrofit technology (BART) for electric generating unit (EGU) emissions of sulfur dioxide (SO_2) and particulate matter.* The BART requirements for SO_2 and PM emissions from EGUs in Arkansas and NO_X emissions from the White Bluff Auxiliary Boiler are satisfied by the Arkansas Regional Haze SO_2 and PM SIP Revision approved [Date 30 days after date of publication of the final rule in the **Federal Register**].

(h) *Other measures addressing reasonable progress.* The reasonable progress requirements for SO_2 and PM emissions are satisfied by the Arkansas Regional Haze SO_2 and PM SIP Revision approved [Date 30 days after date of publication of the final rule in the **Federal Register**], the Arkansas Regional Haze FIP, and the 2008 Arkansas Regional Haze SIP.

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