ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R06–OAR–2008–0727; FRL–9478–2]

Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing to partially approve and partially disapprove a revision to the Arkansas State Implementation Plan (SIP) submitted by the State of Arkansas through the Arkansas Department of Environmental Quality (ADEQ) on September 23, 2008, August 3, 2010, and supplemented on September 27, 2011, that addresses regional haze (RH) for the first implementation period. These revisions were submitted to address the requirements of the Clean Air Act (CAA or Act) and our rules that require states to prevent any future and remedy any existing man-made impairment of visibility in mandatory Class I areas caused by emissions of air pollutants from numerous sources located over a wide geographic area (also referred to as the ''regional haze program''). EPA is also proposing to partially approve and partially disapprove a portion of a SIP revision submitted by the State of Arkansas on April 2, 2008, and supplemented on September 27, 2011, to address the interstate transport requirements of the CAA that the Arkansas SIP contain adequate provisions to prohibit emissions from interfering with measures required in another state to protect visibility. This action is being taken under section 110 and part C of the CAA.

DATES: Comments must be received on or before November 16, 2011.

ADDRESSES: Submit your comments, identified by Docket No. EPA–R06–OAR–2008–0727, by one of the following methods:

- *Federal e-Rulemaking Portal: http://www.regulations.gov.* Follow the online instructions for submitting comments.
- *E-mail:* Mr. Guy Donaldson at *donaldson.guy@epa.gov.* Please also send a copy by e-mail to the person listed in the **FOR FURTHER INFORMATION CONTACT** section below.
- *Mail:* Mr. Guy Donaldson, Chief, Air Planning Section (6PD–L), Environmental Protection Agency, 1445 Ross Avenue, Suite 1200, Dallas, Texas 75202–2733.
- *Hand or Courier Delivery:* Mr. Guy Donaldson, Chief, Air Planning Section (6PD–L), Environmental Protection Agency, 1445 Ross Avenue, Suite 1200, Dallas, Texas 75202–2733. Such deliveries are accepted only between the hours of 8 a.m. and 4 p.m. weekdays, and not on legal holidays. Special arrangements should be made for deliveries of boxed information.
- *Fax:* Mr. Guy Donaldson, Chief, Air Planning Section (6PD–L), at fax number 214–665–7263.

Instructions: Direct your comments to Docket No. EPA–R06–OAR–2008–0727. Our policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or e-mail. The *http://www.regulations.gov* Web site is an ''anonymous access'' system, which means we will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to us without going through *http://www.regulations.gov* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, we recommend that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If we cannot read your comment due to technical difficulties and cannot contact you for clarification, we may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the Air Planning Section (6PD–L), Environmental Protection Agency, 1445 Ross Avenue, Suite 700, Dallas, Texas 75202–2733. The file will be made available by appointment for public inspection in the Region 6 FOIA Review Room between the hours of 8:30 a.m. and 4:30 p.m. weekdays except for legal holidays. Contact the person listed in the **FOR FURTHER INFORMATION CONTACT** paragraph below or Mr. Bill Deese at 214–665–7253 to make an appointment. If possible, please make the appointment at least two working days in advance of your visit. There will be a 15 cent per page fee for making photocopies of documents. On the day of the visit, please check in at our Region 6 reception area at 1445 Ross Avenue, Suite 700, Dallas, Texas.

The State submittal is also available for public inspection during official business hours, by appointment, at the Arkansas Department of Environmental Quality, 5301 Northshore Drive, North Little Rock, AR 72118–5317.

FOR FURTHER INFORMATION CONTACT: Ms. Dayana Medina, Air Planning Section (6PD–L), Environmental Protection Agency, Region 6, 1445 Ross Avenue, Suite 700, Dallas, Texas 75202–2733, telephone 214–665–7241; fax number 214–665–7263; e-mail address *medina.dayana@epa.gov.*

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

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I. Overview of Proposed Actions

A. Regional Haze

We are proposing to partially approve and partially disapprove Arkansas' RH SIP revision submitted on September 23, 2008, August 3, 2010, and supplemented on September 27, 2011, as discussed in sections IV and VI of this proposed rulemaking. Specifically, we are proposing to approve the following: the State's identification of affected Class I areas; the establishment of baseline and natural visibility conditions; the Uniform Rate of Progress (URP); the State's reasonable progress goal (RPG) consultation and the long-term strategy (LTS) consultation; the regional haze monitoring strategy and other SIP requirements under section 51.308(d)(4); the State's commitment to submit periodic regional haze SIP revisions and periodic progress reports describing progress towards the RPGs; the State's commitment to make a determination of the adequacy of the existing SIP at the time a progress report is submitted; and the State's consultation and coordination with Federal land managers (FLMs).

We are proposing to partially approve and partially disapprove those portions addressing the State's identification of BART-eligible sources and subject to BART sources; the requirements for best available retrofit technology (BART); the State's RH Rule; and the LTS. Specifically, we are proposing to approve the State's identification of BART-eligible sources, with the exception of the 6A Boiler at the Georgia-Pacific Crossett Mill, which we find to be BART-eligible. We are proposing to approve the State's identification of subject to BART sources, with the exception of the 6A and 9A Boilers at the Georgia-Pacific Crossett Mill, which we find to be subject to BART. We are also proposing to approve the following BART determinations made by ADEQ: The PM BART determination for the No. 1 Boiler of the American Electric Power (AEP) Flint Creek plant; the SO_2 and PM BART determinations for the natural gas firing scenario for Unit 4 of the Entergy Lake Catherine plant; the PM BART determinations for both the bituminous and sub-bituminous coal firing scenarios for Units 1 and 2 of the Entergy White Bluff plant; and the PM BART determination for the No. 1 Power Boiler of the Domtar Ashdown Mill. We are proposing to disapprove the following BART determinations made by ADEQ: The SO_2, NO_X, and PM BART determinations for both Unit 1 of the Arkansas Electric Cooperative Corporation (AECC) Bailey plant and Unit 1 of the AECC McClellan plant; the SO_2 and NO_X BART determinations for the No. 1 Boiler of the AEP Flint Creek plant; the NO_X BART determination for the natural gas firing scenario and the SO_2, NO_X, and PM BART determinations for the fuel oil firing scenario for Unit 4 of the Entergy Lake Catherine plant; the SO_2 and NO_X BART determinations for both the bituminous and sub-bituminous coal firing scenarios for Units 1 and 2 of the Entergy White Bluff plant; the BART determination for the Auxiliary Boiler of the Entergy White Bluff Plant; the SO_2 and NO_X BART determinations for the No. 1 Power Boiler of the Domtar Ashdown Mill; and the SO_2, NO_X and PM BART determinations for the No. 2 Power Boiler of the Domtar Ashdown Mill. We are proposing to disapprove these BART determinations because they do not comply with our regulations under 40 CFR 51.308(e). The Arkansas RH Rule, the Arkansas Pollution Control and Ecology Commission (APC&E Commission) Regulation 19, Chapter 15, was submitted by ADEQ on September 23, 2008, as part of the RH SIP. On August 3, 2010, we received a SIP submittal from ADEQ revising several chapters of APC&E Commission Regulation 19, including chapter 15. The revisions to Chapter 15 of APC&E Commission Regulation 19 that we received on August 3, 2010, are mostly non-substantive edits to the original rule we received on September 23, 2008. Therefore, in this proposed rulemaking we are proposing to take action on chapter 15 of APC&E Regulation 19 contained in the submittal we received on September 23, 2008, and as revised by the submittal we received on August 3, 2010. We are proposing to approve the portions of APC&E Commission Regulation 19, chapter 15, which we received on September 23, 2008, and as revised on August 3, 2010, that are consistent with the portions of the Arkansas RH SIP we are proposing to approve and we are proposing to disapprove the portions that are consistent with other portions of the Arkansas RH SIP we are proposing to disapprove. We are proposing to partially approve and partially disapprove the State's LTS because the LTS only partially satisfies the requirements under section 51.308(d)(3), and a portion of it relies on portions of the RH SIP we are proposing to disapprove.

We are proposing to disapprove the reasonable progress goals (RPGs) under section 51.308(d)(1) because Arkansas did not consider the factors that states are required to consider in establishing RPGs under the CAA and section 51.308(d)(1)(A).

Under the CAA,[1] we must, within 24 months following a final disapproval, either approve a SIP or promulgate a Federal Implementation Plan (FIP). At this time, we are not proposing a FIP for the portions of the Arkansas RH SIP we are proposing to disapprove because ADEQ has expressed its intent to revise the Arkansas RH SIP by correcting the deficiencies we have identified in this proposal. We are electing to not propose a FIP at this time in order to provide Arkansas time to correct these deficiencies.

B. Interstate Transport and Visibility

We are proposing to partially approve and partially disapprove a portion of the SIP revision we received from the State of Arkansas on April 2, 2008, for the purpose of addressing the ''good neighbor'' provisions of the CAA section 110(a)(2)(D)(i) for the 1997 8-hour ozone NAAQS and the $PM_{2.5}$ NAAQS. Section 110(a)(2)(D)(i)(II) of the Act requires that states have a SIP, or submit a SIP revision, containing provisions ''prohibiting any source or other type of emission activity within the state from emitting any air pollutant in amounts whichwill * * * interfere with measures required to be included in the applicable implementation plan for any other State under part C [of the CAA] to protect visibility.'' Because of the impacts on visibility from the interstate transport of pollutants, we interpret the ''good neighbor'' provisions of section 110 of the Act described above as requiring states to include in their SIPs either measures to prohibit emissions that would interfere with the reasonable progress goals set to protect Class I areas in other states, or a demonstration that emissions from Arkansas sources and activities will not have the prohibited impacts on other states' existing SIPs.

Arkansas stated in its April 2, 2008 submittal that it is relying on the Arkansas RH Rule, the APC&E Commission Regulation 19, Chapter 15, to satisfy the requirements of section 110(a)(2)(D)(i)(II) that emissions from Arkansas sources not interfere with measures required in the SIP of any other state under part C of the CAA to protect visibility. ADEQ also stated in its April 2, 2008 submittal that it is not possible to assess whether there is any interference with the measures in the applicable SIP for another state designed to protect visibility for the 8-hour ozone and $PM_{2.5}$ NAAQS until ADEQ submits and EPA approves Arkansas' RH SIP.

In developing their Regional Haze SIP and RPGs, Arkansas and potentially impacted States collaborated through the Central Regional Air Planning (CENRAP) association. Each State developed its Regional Haze Plans and RPGs based on the CENRAP modeling. The CENRAP modeling was based in part on the emissions reductions each state intended to achieve by 2018. In the case of Arkansas, some of the emissions reductions included in the modeling, and thus relied upon by other States, were from BART controls on Arkansas subject to BART sources. In the State's September 27, 2011 supplemental submission, ADEQ clarified that the base year modeling inventory used by CENRAP in the 2002 base case modeling was prepared by the CENRAP Modeling Workgroup and its consultants, and was derived primarily from the 2002 National Emissions Inventory (NEI). ADEQ also clarified that it provided the CENRAP Modeling Workgroup with the controlled BART source emission limits contained in the State's RH Rule, the APC&E Commission Regulation 19, Chapter 15, for inclusion in the CENRAP's 2018 future case modeling. The State's RH Rule became effective October 15, 2007, and incorporates BART requirements for Arkansas' subject to BART sources. The current language of the regulation requires Arkansas' subject to BART sources to comply with BART requirements no later than five years after EPA approval of the RH SIP or 6 years after the effective date of the regulation, whichever is first. However, on March 26, 2010, the Arkansas Pollution Control and Ecology Commission, the environmental policy-making body for Arkansas, granted all Arkansas subject to BART sources a variance from the compliance deadline imposed by the State's RH Rule, such that these sources are now required to comply with BART requirements no later than 5 years after EPA approval of the RH SIP. Compliance with these BART requirements will ensure that Arkansas obtains its share of the emission reductions relied upon by other states to meet the RPGs for their Class I areas. Since compliance of Arkansas' subject to BART sources with BART requirements is dependent upon our approval of the RH SIP, and since we are proposing to disapprove the portion of the RH SIP which includes some of Arkansas' BART determinations, a portion of the emission reductions committed to by Arkansas and relied upon by other states will not be realized and, as a consequence, Arkansas' emissions will interfere with other states' SIPs to protect visibility. Therefore, we are proposing to partially approve and partially disapprove the portion of the Arkansas Interstate Transport SIP submittal that addresses the visibility requirement of section 110(a)(2)(D)(i)(II) that emissions from Arkansas sources not interfere with measures required in the SIP of any other state under part C of the CAA to protect visibility.

II. What is the background for our proposed actions?

A. Regional Haze

RH is visibility impairment that is produced by a multitude of sources and activities which are located across a broad geographic area and emit fine particles ($PM_{2.5}$) (*e.g.,* sulfates, nitrates, organic carbon, elemental carbon, and soil dust) and their precursors (*e.g.,* SO_2, nitrogen oxides (NO_X), and in some cases, ammonia (NH_3) and volatile organic compounds (VOCs)). Fine particle precursors react in the atmosphere to form $PM_{2.5}$ (*e.g.,* sulfates, nitrates, organic carbon, elemental carbon, and soil dust), which also impair visibility by scattering and absorbing light. Visibility impairment reduces the clarity, color, and visible distance that one can see. $PM_{2.5}$ also can cause serious health effects and mortality in humans and contributes 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 visibility impairment caused by air pollution occurs virtually all the time at most national park and wilderness areas. The average visual range[2] in many Class I areas (*i.e.,* national parks and memorial parks, wilderness areas, and international parks meeting certain size criteria) in the western United States is 100–150 kilometers, or about one-half to two-thirds of the visual range that would exist without anthropogenic air pollution. 64 FR 35714, 35715 (July 1, 1999). In most of the eastern Class I areas of the United States, the average visual range is less than 30 kilometers, or about one-fifth of the visual range

[1] CAA section 110(c)(1).

[2] Visual range is the greatest distance, in kilometers or miles, at which a dark object can be viewed against the sky.

that would exist under estimated natural conditions. *Id.*

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, impairment of visibility in mandatory Class I Federal areas [3] which impairment results from man-made air pollution.'' CAA § 169A(a)(1). The terms ''impairment of visibility'' and ''visibility impairment'' are defined in the Act to include a reduction in visual range and atmospheric discoloration. *Id.* section 169A(g)(6). In 1980, we promulgated regulations to address visibility impairment in Class I areas that is ''reasonably attributable'' to a single source or small group of sources, *i.e.,* ''reasonably attributable visibility impairment'' (RAVI). 45 FR 80084 (December 2, 1980). These regulations represented the first phase in addressing visibility impairment. We deferred action on RH that emanates from a variety of sources until monitoring, modeling and scientific knowledge about the relationships between pollutants and visibility impairment improved.

Congress added section 169B to the CAA in 1990 to address RH issues, and we promulgated regulations addressing RH in 1999. 64 FR 35714 (July 1, 1999), codified at 40 CFR part 51, subpart P. The Regional Haze Rule (RHR) revised the existing visibility regulations to integrate into the regulations provisions addressing RH impairment and established a comprehensive visibility protection program for Class I areas. The requirements for RH, found at 40 CFR 51.308 and 51.309, are included in our visibility protection regulations at 40 CFR 51.300–309. Some of the main elements of the RH requirements are summarized in section III. The requirement to submit a RH SIP applies to all 50 states, the District of Columbia and the Virgin Islands.[4] States were required to submit the first implementation plan addressing RH visibility impairment no later than December 17, 2007. 40 CFR 51.308(b). We received the Arkansas RH SIP on September 23, 2008.

B. Roles of Agencies in Addressing Regional Haze

Successful implementation of the RH program will require long-term regional coordination among states, tribal governments and various federal agencies. As noted above, pollution affecting the air quality in Class I areas can be transported over long distances, even hundreds of kilometers. Therefore, to address effectively the problem of visibility impairment in Class I areas, states need to develop strategies in coordination with one another, taking into account the effect of emissions from one jurisdiction on the air quality in another.

Because the pollutants that lead to RH can originate from sources located across broad geographic areas, we have encouraged the states and tribes across the United States to address visibility impairment from a regional perspective. Five regional planning organizations (RPOs) were developed to address RH and related issues. The RPOs first evaluated technical information to better understand how their states and tribes impact Class I areas across the country, and then pursued the development of regional strategies to reduce emissions of particulate matter (PM) and other pollutants leading to RH.

The CENRAP is an organization of states, tribes, federal agencies and other interested parties that identifies RH and visibility issues and develops strategies to address them. CENRAP is one of the five RPOs across the U.S. and includes the states and tribal areas of Nebraska, Kansas, Oklahoma, Texas, Minnesota, Iowa, Missouri, Arkansas, and Louisiana.

C. The 1997 NAAQS for Ozone and $PM_{2.5}$ and CAA 110(a)(2)(D)(i)

On July 18, 1997, we promulgated new NAAQS for 8-hour ozone and for $PM_{2.5}$. 62 FR 38652. Section 110(a)(1) of the CAA requires states to submit SIPs to address a new or revised NAAQS within 3 years after promulgation of such standards, or within such shorter period as we may prescribe. Section 110(a)(2) of the CAA lists the elements that such new SIPs must address, including section 110(a)(2)(D)(i), which pertains to the interstate transport of certain emissions. Thus, states were required to submit SIPs that satisfy the applicable requirements under sections 110(a)(1) and (2), including the requirements of section 110(a)(2)(D)(i), by July 2000. States, including Arkansas, did not meet the statutory July 2000 deadline for submission of these SIPs. Accordingly, on April 25, 2005, EPA made findings of failure to submit, notifying all states, including Arkansas, of their failure to make the required SIP submission to address interstate transport under section 110(a)(2)(D)(i). 70 FR 21147. This finding started a 24-month FIP clock under section 110(c). Pursuant to section 110(c), we are required to promulgate a FIP to address the applicable interstate transport requirements, unless the State makes the required submission and we fully approve such submission, within the 24-month period.

On August 15, 2006, we issued our ''Guidance for State Implementation Plan (SIP) Submissions to Meet Current Outstanding Obligations Under Section 110(a)(2)(D)(i) for the 8-Hour Ozone and $PM_{2.5}$ National Ambient Air Quality Standards'' (2006 Guidance). We developed the 2006 Guidance to make recommendations to states for making submissions to meet the requirements of section 110(a)(2)(D)(i) for the 1997 8-hour ozone standards and the 1997 $PM_{2.5}$ standards.

As identified in the 2006 Guidance, the ''good neighbor'' provisions in section 110(a)(2)(D)(i) of the CAA require each state to submit a SIP that prohibits emissions that adversely affect another state in the ways contemplated in the statute. Section 110(a)(2)(D)(i) contains four distinct requirements related to the impacts of interstate transport. The SIP must prevent sources in the state from emitting pollutants in amounts which will: (1) Contribute significantly to nonattainment of the NAAQS in other states; (2) interfere with maintenance of the NAAQS in other states; (3) interfere with provisions to prevent significant deterioration of air quality in other states; or (4) interfere with efforts to protect visibility in other states. In this action, we only address the fourth element regarding visibility.

The 2006 Guidance stated that states may make a simple SIP submission confirming that it is not possible at that time to assess whether there is any

[3] Areas designated as mandatory Class I Federal areas consist of national parks exceeding 6000 acres, wilderness areas and national memorial parks exceeding 5000 acres, and all international parks that were in existence on August 7, 1977. *See* CAA section 162(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. *See* 44 FR 69122, November 30, 1979. The extent of a mandatory Class I area includes subsequent changes in boundaries, such as park expansions. CAA section 162(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'' (FLM). *See* CAA section 302(i). When we use the term ''Class I area'' in this action, we mean a ''mandatory Class I Federal area.''

[4] Albuquerque/Bernalillo County in New Mexico must also submit a regional haze SIP to completely satisfy the requirements of section 110(a)(2)(D) of the CAA for the entire State of New Mexico under the New Mexico Air Quality Control Act (section 74–2–4).

interference with measures in the applicable SIP for another state designed to ''protect visibility'' for the 8-hour ozone and $PM_{2.5}$ NAAQS until RH SIPs are submitted and approved. RH SIPs were required to be submitted by December 17, 2007. *See* 74 FR 2392 (January 15, 2009).

On April 2, 2008, we received a SIP revision from Arkansas to address the interstate transport provisions of CAA 110(a)(2)(D)(i) for the 1997 ozone and $PM_{2.5}$ NAAQS. For the reasons discussed in section V of this proposed rulemaking, a portion of the emission reductions committed to by Arkansas and relied upon by other states will not be realized and Arkansas' emissions will interfere with other states' SIPs to protect visibility. Therefore, we are proposing to partially approve and partially disapprove the portion of the Arkansas Interstate Transport SIP submittal that addresses the requirement that emissions from Arkansas sources not interfere with measures required in the SIP of any other state to protect visibility. *See* CAA section 110(a)(2)(D)(i)(II).

We recognize that we have an outstanding obligation to promulgate a FIP for the portion of the Arkansas Interstate Transport SIP submittal we are proposing to disapprove. However, because we are not proposing a FIP for the portions of the Arkansas RH SIP we are proposing to disapprove at this time in order to provide Arkansas time to correct the deficiencies identified in this proposal, we are likewise not proposing a FIP at this time for the disapproved portion of the Arkansas Interstate Transport SIP. We believe it is appropriate to address the concerns with the Regional Haze SIP and the Interstate Transport SIP at the same time and it is appropriate, in this instance, to allow the state an opportunity to address the deficiencies we have identified in this proposed action before imposing a FIP. If we were to propose a FIP for the disapproved portion of the Arkansas Interstate Transport SIP without also proposing a FIP for the disapproved portions of the Arkansas RH SIP, this could potentially result in Arkansas' subject to BART sources being required to install two successive levels of control measures, the first in order to meet the requirements of section 110(a)(2)(D)(i), and the second in order to meet the requirements of the RH program. This would result in an inefficient use of resources by both the affected sources and us.

III. What are the requirements for regional haze SIPs?

The following is a summary and basic explanation of the regulations covered under the RHR. See 40 CFR 51.308 for a complete listing of the regulations under which this SIP was evaluated.

A. The CAA and the Regional Haze Rule

RH SIPs must assure reasonable progress towards the national goal of achieving natural visibility conditions in Class I areas. Section 169A of the CAA and our implementing regulations require states to establish long-term strategies for making reasonable progress toward meeting this goal. Implementation plans must also give specific attention to certain stationary sources that were in existence on August 7, 1977, but were not in operation before August 7, 1962, and require these sources, where appropriate, to install BART controls for the purpose of eliminating or reducing visibility impairment. The specific RH SIP requirements are discussed in further detail below.

B. Determination of Baseline, Natural, and Current Visibility Conditions

The RHR establishes the deciview (dv) as the principal metric for measuring visibility. *See* 70 FR 39104. This visibility metric expresses uniform changes in the degree of haze in terms of common increments across the entire range of visibility conditions, from pristine to extremely hazy conditions. Visibility is sometimes expressed in terms of the visual range, which is the greatest distance, in kilometers or miles, at which a dark object can just be distinguished against the sky. The deciview is a useful measure for tracking progress in improving visibility, because each deciview change is an equal incremental change in visibility perceived by the human eye. Most people can detect a change in visibility of one deciview.[5]

The deciview is used in expressing Reasonable Progress Goals (RPGs) (which are interim visibility goals towards meeting the national visibility goal), defining baseline, current, and natural conditions, and tracking changes in visibility. The RH SIPs must contain measures that ensure ''reasonable progress'' toward the national goal of preventing and remedying visibility impairment in Class I areas caused by man-made air pollution by reducing anthropogenic emissions that cause RH. The national goal is a return to natural conditions, *i.e.,* man-made sources of air pollution would no longer impair visibility in Class I areas.

To track changes in visibility over time at each of the 156 Class I areas covered by the visibility program (40 CFR 81.401–437), and as part of the process for determining reasonable progress, states must calculate the degree of existing visibility impairment at each Class I area at the time of each RH SIP submittal and periodically review progress every five years midway through each 10-year implementation period. To do this, the RHR requires states to determine the degree of impairment (in deciviews) for the average of the 20 percent least impaired (''best'') and 20 percent most impaired (''worst'') visibility days over a specified time period at each of their Class I areas. In addition, states must also develop an estimate of natural visibility conditions for the purpose of comparing progress toward the national goal. Natural visibility is determined by estimating the natural concentrations of pollutants that cause visibility impairment and then calculating total light extinction based on those estimates. We have provided guidance to states regarding how to calculate baseline, natural and current visibility conditions.[6]

For the first RH SIPs that were due by December 17, 2007, ''baseline visibility conditions'' were the starting points for assessing ''current'' visibility impairment. Baseline visibility conditions represent the degree of visibility impairment for the 20 percent least impaired days and 20 percent most impaired days for each calendar year from 2000 to 2004. Using monitoring data for 2000 through 2004, states are required to calculate the average degree of visibility impairment for each Class I area, based on the average of annual values over the five-year period. The comparison of initial baseline visibility conditions to natural visibility conditions indicates the amount of improvement necessary to attain natural visibility, while the future comparison of baseline conditions to the then current conditions will indicate the amount of progress made. In general, the 2000–2004 baseline period is considered the time from which improvement in visibility is measured.

[5] The preamble to the RHR provides additional details about the deciview. 64 FR 35714, 35725 (July 1, 1999).

[6] *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule,* September 2003, EPA–454/B–03–005, *available* at *http://www.epa.gov/ttncaaa1/t1/memoranda/rh_envcurhr_gd.pdf,* (hereinafter referred to as ''our 2003 Natural Visibility Guidance''); and *Guidance for Tracking Progress Under the Regional Haze Rule,* (EPA–454/B–03–004, September 2003, *available* at *http://www.epa.gov/ttncaaa1/t1/memoranda/rh_tpurhr_gd.pdf,* (hereinafter referred to as our ''2003 Tracking Progress Guidance'').

C. Determination of Reasonable Progress Goals

The vehicle for ensuring continuing progress towards achieving the natural visibility goal is the submission of a series of RH SIPs from the states that establish two RPGs (*i.e.,* two distinct goals, one for the ''best'' and one for the ''worst'' days) for every Class I area for each (approximately) 10-year implementation period. *See* 70 FR 3915; *see also* 64 FR 35714. The RHR does not mandate specific milestones or rates of progress, but instead calls for states to establish goals that provide for ''reasonable progress'' toward achieving natural (*i.e.,* ''background'') visibility conditions. In setting RPGs, states must provide for an improvement in visibility for the most impaired days over the (approximately) 10-year period of the SIP, and ensure no degradation in visibility for the least impaired days over the same period. *Id.*

States have significant discretion in establishing RPGs, but are required to consider the following factors established in section 169A of the CAA and in our RHR at 40 CFR 51.308(d)(1)(i)(A): (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 the RPGs for the best and worst days for each applicable Class I area. States have considerable flexibility in how they take these factors into consideration, as noted in our Reasonable Progress Guidance[7]. In setting the RPGs, states must also consider the rate of progress needed to reach natural visibility conditions by 2064 (referred to hereafter as the ''Uniform Rate of Progress (URP)'' and the emission reduction measures needed to achieve that rate of progress over the 10-year period of the SIP. Uniform progress towards achievement of natural conditions by the year 2064 represents a rate of progress, which states are to use for analytical comparison to the amount of progress they expect to achieve. In setting RPGs, each state with one or more Class I areas (''Class I State'') must also consult with potentially ''contributing states,'' *i.e.,* other nearby states with emission sources that may be affecting visibility impairment at the Class I State's areas. 40 CFR 51.308(d)(1)(iv).

D. Best Available Retrofit Technology

Section 169A of the CAA directs states to evaluate the use of retrofit controls at certain larger, often uncontrolled, older stationary sources with the potential to emit greater than 250 tons or more of any pollutant in order to address visibility impacts from these sources. Specifically, section 169A(b)(2)(A) of the Act requires states to revise their SIPs to contain such measures as may be necessary to make reasonable progress towards the natural visibility goal, including a requirement that certain categories of existing major stationary sources[8] built between 1962 and 1977 procure, install, and operate the ''Best Available Retrofit Technology'' (BART), as determined by the state or us in the case of a plan promulgated under section 110(c) of the CAA. Under the RHR, States are directed to conduct BART determinations for such ''BART-eligible'' sources that may be anticipated to cause or contribute to any visibility impairment in a Class I area. 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 greater reasonable progress towards improving visibility than BART.

We promulgated regulations addressing RH in 1999, 64 FR 35714 (July 1, 1999), codified at 40 CFR part 51, subpart P.[9] These regulations require all states to submit implementation plans that, among other measures, contain either emission limits representing BART for certain sources constructed between 1962 and 1977, or alternative measures that provide for greater reasonable progress than BART. 40 CFR 51.308(e).

On July 6, 2005, we published the *Guidelines for BART Determinations Under the Regional Haze Rule* at Appendix Y to 40 CFR part 51 (''BART Guidelines'') to assist states in determining which of their sources should be subject to the BART requirements and in determining appropriate emission limits for each applicable source. 70 FR 39104. In making a BART determination for a fossil fuel-fired electric generating plant with a total generating capacity in excess of 750 megawatts (MW), a state must use the approach set forth in the BART Guidelines. A state is encouraged, but not required, to follow the BART Guidelines in making BART determinations for other types of sources.

The process of establishing BART emission limitations can be logically broken down into three steps: first, states identify those sources which meet the definition of ''BART-eligible source'' set forth in 40 CFR 51.301[10]; second, states determine whether such sources ''emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area'' (a source which fits this description is ''subject to BART,'') and; third, for each source subject to BART, states then identify the appropriate type and the level of control for reducing emissions.

States must address all visibility-impairing pollutants emitted by a source in the BART determination process. The most significant visibility impairing pollutants are SO_2, NO_X, and PM. We have stated that states should use their best judgment in determining whether VOC or ammonia compounds impair visibility in Class I areas.

Under the BART Guidelines, states may select an exemption threshold value for their BART modeling, below which a BART-eligible source would not be expected to cause or contribute to visibility impairment in any Class I area. The state must document this exemption threshold value in the SIP and must state the basis for its selection of that value. Any source with emissions that model above the threshold value would be subject to a BART determination review. The BART Guidelines acknowledge varying circumstances affecting different Class I areas. States should consider the number of emission sources affecting the Class I areas at issue and the magnitude of the individual sources' impacts. Any exemption threshold set by the state should not be higher than 0.5 dv. See also 40 CFR part 51, Appendix Y, section III.A.1.

In their SIPs, states must identify potential BART sources, described as ''BART-eligible sources'' in the RHR, and document their BART control determination analyses. The term ''BART-eligible source'' used in the

[7] *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).

[8] The set of ''major stationary sources'' potentially subject to BART are listed in CAA section 169A(g)(7).

[9] In *American Corn Growers Ass'n* v. *EPA,* 291 F.3d 1 (D.C. Cir. 2002), the U.S Court of Appeals for the District of Columbia Circuit issued a ruling vacating and remanding the BART provisions of the regional haze rule. In 2005, we issued BART guidelines to address the court's ruling in that case. *See* 70 FR 39104 (July 6, 2005).

[10] BART-eligible sources are those sources that have the potential to emit 250 tons or more of a visibility-impairing air pollutant, were put in place between August 7, 1962 and August 7, 1977, and whose operations fall within one or more of 26 specifically listed source categories.

BART Guidelines means the collection of individual emission units at a facility that together comprises the BART-eligible source. In making BART determinations, section 169A(g)(2) of the CAA requires that states consider the following factors: (1) The costs of compliance; (2) the energy and non-air 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. States are free to determine the weight and significance to be assigned to each factor. *See* 40 CFR 51.308(e)(1)(ii).

A RH SIP must include source-specific BART emission limits and compliance schedules for each source subject to BART. Once a state has made its BART determination, the BART controls must be installed and in operation as expeditiously as practicable, but no later than five years after the date of our approval of the RH SIP. CAA section 169(g)(4) and 40 CFR 51.308(e)(1)(iv). In addition to what is required by the RHR, general SIP requirements mandate that the SIP must also include all regulatory requirements related to monitoring, recordkeeping, and reporting for the BART controls on the source. *See* CAA section 110(a). As noted above, the RHR allows states to implement an alternative program in lieu of BART so long as the alternative program can be demonstrated to achieve greater reasonable progress toward the national visibility goal than would BART.

E. Long-Term Strategy (LTS)

Consistent with the requirement in section 169A(b) of the CAA that states include in their regional haze SIP a 10 to 15 year strategy for making reasonable progress, Section 51.308(d)(3) of the RHR requires that states include a LTS in their RH SIPs. The LTS 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. The LTS 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. 40 CFR 51.308(d)(3).

When a state's emissions are reasonably anticipated to cause or contribute to visibility impairment in a Class I area located in another state, the RHR requires the impacted state to coordinate with the contributing states in order to develop coordinated emissions management strategies. 40 CFR 51.308(d)(3)(i). Also, a state with a Class I area impacted by emissions from another state must consult with such contributing state, (*id.*) and must also demonstrate that it has included in its SIP all measures necessary to obtain its share of emission reductions needed to meet the reasonable progress goals for the Class I area. *Id.* at (d)(3)(ii). In such cases, the contributing state must demonstrate that it has included, in its SIP, all measures necessary to obtain its share of the emission reductions needed to meet the RPGs for the Class I area. The RPOs have provided forums for significant interstate consultation, but additional consultations between states may be required to sufficiently address interstate visibility issues. This is especially true where two states belong to different RPOs.

States should consider all types of anthropogenic sources of visibility impairment in developing their LTS, including stationary, minor, mobile, and area sources. At a minimum, states must describe how each of the following seven factors listed below are taken into account in developing their LTS: (1) Emission reductions due to ongoing air pollution control programs, including measures to address RAVI; (2) measures to mitigate the impacts of construction activities; (3) emissions limitations and schedules for compliance to achieve the RPG; (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; (7) the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the LTS. 40 CFR 51.308(d)(3)(v).

F. Coordinating Regional Haze and Reasonably Attributable Visibility Impairment

As part of the RHR, we revised 40 CFR 51.306(c) regarding the LTS for RAVI to require that the RAVI plan must provide for a periodic review and SIP revision not less frequently than every three years until the date of submission of the state's first plan addressing RH visibility impairment, which was due December 17, 2007, in accordance with 40 CFR 51.308(b) and (c). On or before this date, the state must revise its plan to provide for review and revision of a coordinated LTS for addressing RAVI and RH, and the state must submit the first such coordinated LTS with its first RH SIP. Future coordinated LTS and periodic progress reports evaluating progress towards RPGs, must be submitted consistent with the schedule for SIP submission and periodic progress reports set forth in 40 CFR 51.308(f) and 51.308(g), respectively. The periodic review of a state's LTS must report on both RH and RAVI impairment and must be submitted to us as a SIP revision.

G. Monitoring Strategy and Other SIP Requirements

Section 51.308(d)(4) of the RHR includes the requirement for a monitoring strategy for measuring, characterizing, and reporting of RH visibility impairment that is representative of all mandatory Class I Federal areas within the state. The strategy must be coordinated with the monitoring strategy required in section 51.305 for RAVI. Compliance with this requirement may be met through ''participation'' in the Interagency Monitoring of Protected Visual Environments (IMPROVE) network, *i.e.,* review and use of monitoring data from the network. The monitoring strategy is due with the first RH SIP, and it must be reviewed every five (5) years. The monitoring strategy must also provide for additional monitoring sites if the IMPROVE network is not sufficient to determine whether RPGs will be met.

The SIP must also provide for the following:

- Procedures for using monitoring data and other information in a state with mandatory Class I areas to determine the contribution of emissions from within the state to RH visibility impairment at Class I areas both within and outside the state;
- Procedures for using monitoring data and other information in a state with no mandatory Class I areas to determine the contribution of emissions from within the state to RH visibility impairment at Class I areas in other states;
- Reporting of all visibility monitoring data to the Administrator at least annually for each Class I area in the state, and where possible, in electronic format;
- Developing a statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any Class I area. The inventory must include emissions for a baseline year, emissions for the most recent year for which data are available, and estimates of future projected emissions. A state must also make a commitment to update the inventory periodically; and

• Other elements, including reporting, recordkeeping, and other measures necessary to assess and report on visibility.

The RHR requires control strategies to cover an initial implementation period extending to the year 2018, with a comprehensive reassessment and revision of those strategies, as appropriate, every 10 years thereafter. Periodic SIP revisions must meet the core requirements of section 51.308(d) with the exception of BART. The requirement to evaluate sources for BART applies only to the first RH SIP. Facilities subject to BART must continue to comply with the BART provisions of section 51.308(e), as noted above. Periodic SIP revisions will assure that the statutory requirement of reasonable progress will continue to be met.

H. Consultation With States and Federal Land Managers

The RHR requires that states consult with Federal Land Managers (FLMs) before adopting and submitting their SIPs. 40 CFR 51.308(i). States must provide FLMs an opportunity for consultation, in person and at least 60 days prior to holding any public hearing on the SIP. This consultation must include the opportunity for the FLMs to discuss their assessment of impairment of visibility in any Class I area and to offer recommendations on the development of the RPGs and on the development and implementation of strategies to address visibility impairment. Further, a state must include in its SIP a description of how it addressed any comments provided by the FLMs. Finally, a SIP must provide procedures for continuing consultation between the state and FLMs regarding the state's visibility protection program, including development and review of SIP revisions, five-year progress reports, and the implementation of other programs having the potential to contribute to impairment of visibility in Class I areas.

IV. Our Analysis of Arkansas' Regional Haze SIP

On September 23, 2008, we received a RH SIP revision from the State of Arkansas for approval into the Arkansas SIP. We received a supplemental submission to the RH SIP revision on September 27, 2011. In addition, we received a submittal revising several chapters of APC&E Commission Regulation 19, including Chapter 15 (Arkansas' RH Rule), on August 3, 2010. In this proposed rulemaking, the only portions of the August 3, 2010, submittal we are proposing to take action on are those addressing Chapter 15 of APC&E Commission Regulation 19. The following is a discussion of our evaluation of these submissions. The parts of the submittals that are interrelated are discussed together, in order to provide the reader with a more ready understanding of our evaluation. See the Technical Support Document (TSD) for this proposal for a step-wise evaluation of ADEQ's submissions in the order in which the regulations appear in 40 CFR 51.308, and a more comprehensive technical analysis.[11]

A. Affected Class I Areas

In accordance with 40 CFR 51.308(d), ADEQ has identified two Class I areas within its borders, the Caney Creek Wilderness Area (Caney Creek) in Ouachita National Forest and the Upper Buffalo Wilderness Area (Upper Buffalo) in the Ozark National Forest. ADEQ is responsible for developing RPGs for these two Class I areas. ADEQ has also determined that Arkansas emissions cause and contribute to visibility impairment at the two Class I areas in Missouri: Hercules Glades Wilderness Area (Hercules Glades) and Mingo National Wildlife Refuge (Mingo). The TSD for the CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation (TSD for CENRAP modeling) demonstrates Arkansas sources are responsible for a visibility extinction of approximately 7.1 inverse megameters[12] (Mm^{-1}) at Hercules Glades and for a visibility extinction of approximately 4.95 Mm^{-1} at Mingo on the worst 20% days for 2002.[13] As discussed in section IV.C.3 of this proposed rulemaking, ADEQ consulted with the appropriate state air quality agency in Missouri to reach an agreement on whether it is necessary for Arkansas to commit to additional emission reductions that would help Missouri achieve its RPGs for Hercules Glades and Mingo.

B. Determination of Baseline, Natural and Current Visibility Conditions

As required by section 51.308(d)(2)(i) of the RHR and in accordance with EPA's 2003 Natural Visibility Guidance,[14] ADEQ calculated baseline/current[15] and natural visibility conditions for its two Class I areas, Caney Creek and Upper Buffalo, on the most impaired and least impaired days, as summarized below (and further described in the TSD).

1. Estimating Natural Visibility Conditions

Natural background visibility, as defined in EPA's 2003 Natural Visibility Guidance, is estimated by calculating the expected light extinction using default estimates of natural concentrations of fine particle components adjusted by site-specific estimates of humidity. This calculation uses the IMPROVE equation, which is a formula for estimating light extinction from the estimated natural concentrations of fine particle components (or from components measured by the IMPROVE monitors). As documented in EPA's 2003 Natural Visibility Guidance, EPA allows states to use "refined" or alternative approaches to 2003 EPA guidance to estimate the values that characterize the natural visibility conditions of Class I areas. One alternative approach is to develop and justify the use of alternative estimates of natural concentrations of fine particle components. Another alternative is to use the "new IMPROVE equation" that was adopted for use by the IMPROVE Steering Committee in December 2005[16]. The purpose of this refinement to the "old IMPROVE equation" is to provide more accurate estimates of the various factors that affect the calculation of light extinction.

ADEQ opted to use the new IMPROVE equation to calculate the "refined" natural visibility conditions. This is an acceptable approach under our 2003

[11] The TSD can be found in the docket for this proposal at *http://www.regulations.gov*. The docket number is EPA–R06–OAR–2008–0727.

[12] An inverse megameter is the direct measurement unit for visibility impairment data. It is the amount of light scattered and absorbed as it travels over a distance of one million meters. Deciviews (dv) can be calculated from extinction data as follows: $dv = 10 \times \ln(b_{ext}(Mm^{-1})/10)$, where dv stands for "deciviews;" ln stands for "natural logarithm;" and b_{ext} stands for "extinction value."

[13] See Appendix E of the TSD for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation, found in Appendix 8.1 of the Arkansas RH SIP.

[14] Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule, EPA–454/B–03–005, September 2003.

[15] Since this is the first RH SIP submittal, the calculated baseline visibility condition and the current visibility condition will be the same. It is expected that subsequent RH SIP submittals will reflect different calculated numbers for baseline and current visibility conditions due to the change in conditions.

[16] The IMPROVE program is a cooperative measurement effort governed by a steering committee composed of representatives from Federal agencies (including representatives from EPA and the FLMs) and RPOs. The IMPROVE monitoring program was established in 1985 to aid the creation of Federal and State implementation plans for the protection of visibility in Class I areas. One of the objectives of IMPROVE is to identify chemical species and emission sources responsible for existing anthropogenic visibility impairment. The IMPROVE program has also been a key participant in visibility-related research, including the advancement of monitoring instrumentation, analysis techniques, visibility modeling, policy formulation and source attribution field studies.

Natural Visibility Guidance. For Caney Creek, ADEQ used the new IMPROVE equation to calculate the ''refined'' natural visibility value for the 20 percent worst days to be 11.58 deciviews and for the 20 percent best days to be 4.23 deciviews. For Upper Buffalo, ADEQ used the new IMPROVE equation to calculate the ''refined'' natural visibility value for the 20 percent worst days to be 11.57 deciviews and for the 20 percent best days to be 4.18 deciviews. We have reviewed ADEQ's estimates of the natural visibility conditions for Caney Creek and Upper Buffalo and are proposing to find these acceptable using the new IMPROVE equation.

The new IMPROVE equation takes into account the most recent review of the science [17] and it accounts for the effect of particle size distribution on light extinction efficiency of sulfate (SO_4), nitrate (NO_3), and organic carbon. It also adjusts the mass multiplier for organic carbon (particulate organic matter) by increasing it from 1.4 to 1.8. New terms are added to the equation to account for light extinction by sea salt and light absorption by gaseous nitrogen dioxide. Site-specific values are used for Rayleigh scattering (scattering of light due to atmospheric gases) to account for the site-specific effects of elevation and temperature. Separate relative humidity enhancement factors are used for small and large size distributions of ammonium sulfate and ammonium nitrate and for sea salt. The terms for the remaining contributors, elemental carbon (light-absorbing carbon), fine soil, and coarse mass terms, do not change between the original and new IMPROVE equations.

2. Estimating Baseline Visibility Conditions

As required by section 51.308(d)(2)(i) of the RHR and in accordance with EPA's 2003 Natural Visibility Guidance [18], ADEQ calculated baseline visibility conditions for Caney Creek and Upper Buffalo. The baseline condition calculation begins with the calculation of light extinction, using the IMPROVE equation. The IMPROVE equation sums the light extinction [19] resulting from individual pollutants, such as sulfates and nitrates. As with the natural visibility conditions calculation, ADEQ chose to use the new IMPROVE equation.

The period for establishing baseline visibility conditions is 2000–2004, and baseline conditions must be calculated using available monitoring data. 40 CFR 51.308(d)(2). The IMPROVE monitor at Caney Creek was installed between 2000 and 2002, and therefore ADEQ used visibility data for 2002–2004. The resulting baseline conditions represent an average for 2002–2004. ADEQ calculated the baseline conditions at Caney Creek as 26.36 deciviews on the 20 percent worst days, and 11.24 deciviews on the 20 percent best days. In calculating the baseline conditions at Upper Buffalo, ADEQ used visibility data for 2000–2004. ADEQ calculated the baseline conditions at Upper Buffalo as 26.27 deciviews on the 20 percent worst days, and 11.71 deciviews on the 20 percent best days. We have reviewed ADEQ's estimation of baseline visibility conditions at Caney Creek and Upper Buffalo and are proposing to find these estimates acceptable.

3. Natural Visibility Impairment

To address 40 CFR 51.308(d)(2)(iv)(A), ADEQ also calculated the number of deciviews by which baseline conditions exceed natural visibility conditions for the best and worst days at Caney Creek and Upper Buffalo. At Caney Creek for the 20 percent worst days, ADEQ calculated the number of deciviews by which baseline conditions exceed natural visibility conditions to be 14.78 dv (baseline of 26.36 dv − natural conditions of 11.58 dv). For the 20 percent best days at Caney Creek, the baseline conditions exceed natural visibility conditions by 7.01 dv (baseline of 11.24 dv − natural conditions of 4.23 dv). At Upper Buffalo for the 20% worst days, ADEQ calculated the number of deciviews by which baseline conditions exceed natural visibility conditions to be 14.7 dv (baseline of 26.27 dv − natural conditions of 11.57 dv). For the 20 percent best days at Upper Buffalo, the baseline conditions exceed natural visibility conditions by 7.53 dv (baseline of 11.71 dv − natural conditions of 4.18 dv). We have reviewed ADEQ's estimates of the natural visibility impairment at Caney Creek and Upper Buffalo and are proposing to find these estimates acceptable.

4. Uniform Rate of Progress

In setting the RPGs, ADEQ analyzed and determined the Uniform Rate of Progress (URP) needed to reach natural visibility conditions by the year 2064. In so doing, ADEQ compared the baseline visibility conditions to the natural visibility conditions in Caney Creek and compared the baseline visibility conditions to the natural visibility conditions in Upper Buffalo (as described above), and determined the uniform rate of progress needed in order to attain natural visibility conditions by 2064. ADEQ constructed the URP consistent with the requirements of the RHR and our 2003 Tracking Progress Guidance by plotting a straight graphical line from the baseline level of visibility impairment for 2000–2004 to the level of visibility conditions representing no anthropogenic impairment in 2064 for Caney Creek and for Upper Buffalo.

Using a baseline visibility value of 26.36 dv and a ''refined'' natural visibility value of 11.58 dv for the 20 percent worst days for Caney Creek, ADEQ calculated the URP to be approximately 0.246 dv per year. This results in a total reduction of 14.78 dv that are necessary to reach the natural visibility condition of 11.58 dv in 2064 for Caney Creek. The URP results in a visibility improvement of 3.45 dv for Caney Creek for the period covered by this SIP revision submittal (up to and including 2018).

Using a baseline visibility value of 26.27 dv and a ''refined'' natural visibility value of 11.57 dv for the 20 percent worst days for Upper Buffalo, ADEQ calculated the URP to be approximately 0.245 dv per year. This results in a total reduction of 14.70 dv that are necessary to reach the natural visibility condition of 11.57 dv in 2064 for Upper Buffalo. The URP results in a visibility improvement of 3.43 dv for Upper Buffalo for the period covered by this SIP revision submittal (up to and including 2018).

[17] The science behind the revised IMPROVE equation is summarized in Appendix 5.1 of the Arkansas RH SIP and in numerous published papers. See for example: Hand, J.L., and Malm, W.C., 2006, *Review of the IMPROVE Equation for Estimating Ambient Light Extinction Coefficients—Final Report.* March 2006. Prepared for Interagency Monitoring of Protected Visual Environments (IMPROVE), Colorado State University, Cooperative Institute for Research in the Atmosphere, Fort Collins, Colorado, available at *http://vista.cira.colostate.edu/improve/publications/GrayLit/016_IMPROVEeqReview/IMPROVEeqReview.htm* and Pitchford, Marc., 2006, *Natural Haze Levels II: Application of the New IMPROVE Algorithm to Natural Species Concentrations Estimates.* Final Report of the Natural Haze Levels II Committee to the RPO Monitoring/Data Analysis Workgroup. September 2006, available at *http://vista.cira.colostate.edu/improve/Publications/GrayLit/029_NaturalCondII/naturalhazelevelsIIreport.ppt.*

[18] Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule, EPA–454/B–03–005, September 2003.

[19] The amount of light lost as it travels over one million meters. The haze index, in units of deciviews (dv), is calculated directly from the total light extinction, b_{ext} expressed in inverse megameters (Mm^{-1}), as follows: $HI = 10 \ln(b_{ext}/10)$.

TABLE 1—SUMMARY OF UNIFORM RATE OF PROGRESS

Visibility metric	Caney Creek	Upper Buffalo
Baseline Conditions	26.36 dv	26.27 dv.
Natural Visibility	11.58 dv	11.57 dv.
Total Improvement by 2064	14.78 dv	14.70 dv.
Improvement for this SIP by 2018	3.45 dv	3.43 dv.
Uniform Rate of Progress	0.246 dv/year	0.245 dv/year.

We are proposing to find that ADEQ has appropriately calculated the URP and has satisfied the requirement in section 51.308(d)(1)(i)(B).

C. Evaluation of Arkansas' Reasonable Progress Goals

We are proposing to disapprove Arkansas's Reasonable Progress Goals because the State did not establish the RPGs for Caney Creek and Upper Buffalo in accordance with the requirements of the RHR. As a result, ADEQ's RH SIP fails to ensure adequate reasonable progress toward meeting the national visibility goal. Section 169A(g)(1) of the CAA and section 51.308(d)(1)(i)(A) of the RHR require states to take into account certain factors in establishing its reasonable progress goals and to demonstrate how those factors were taken into consideration in selecting the goals. ADEQ did not do so. We do note that ADEQ did consult with other states regarding the development of RPGs in accordance with the RHR, but this is not enough for us to approve the RPGs.

1. Establishment of the Reasonable Progress Goal

ADEQ adopted the CENRAP modeled 2018 visibility conditions as the RPGs for Caney Creek and Upper Buffalo Class I areas. ADEQ established a RPG of 22.48 dv for Caney Creek for 2018 for the 20% worst days. This represents a 3.88 dv improvement over a baseline of 26.36 dv. For Upper Buffalo, ADEQ established a RPG of 22.52 dv for 2018 for the 20% worst days, which represents a 3.75 dv improvement over a baseline of 26.27 dv. ADEQ calculated that under its RPGs, it would attain natural visibility conditions in 2062 for Caney Creek and 2063 for Upper Buffalo. The CENRAP's projections for 2018 for the 20% best days for Caney Creek and Upper Buffalo, which represent ADEQ's RPGs for the 20% best days, are shown in Figures 10.4 and 10.6 of the RH SIP and in Appendix D to the TSD for CENRAP Emissions and Air Quality Modeling to Support RH State Implementation.[20] A comparison of ADEQ's RPGs to baseline conditions on the least impaired days shows that control of Arkansas sources will result in no degradation in visibility conditions in the first planning period. The CENRAP modeling shows that for the 20% best days, there would be a 0.89 dv and a 0.91 dv improvement in visibility from the baseline for Caney Creek and Upper Buffalo, respectively.

ADEQ established RPGs that ensure no degradation in visibility for the least impaired days. See 40 CFR 51.308(d)(1). However, in setting its RPGs for its Class I areas for the 20% worst days, the State relied on the fact that the emission reductions from BART and from the implementation of other requirements of the CAA would result in RPGs that provided for a slightly greater rate of improvement in visibility than would be needed to attain the URP. Based on this fact, ADEQ did not undertake any further analysis. As discussed below, we do not believe this provides sufficient analysis under section 169A of the CAA and our RHR, and discuss it further in the next section.

2. ADEQ's Reasonable Progress ''Four Factor'' Analysis

In establishing a RPG for a Class I Federal area located within a state, the State is required by CAA § 169A(g)(1) and 40 CFR 51.308(d)(1)(i)(A) to ''[c]onsider 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, and include a demonstration showing how these factors were taken into consideration in selecting the goal.'' In addition to this explicit statutory requirement, the RHR also establishes an analytical requirement to ensure that each State considers carefully the suite of emission reduction measures necessary to attain the URP. The RHR provides that EPA will consider both the State's consideration of the four factors in section 51.308(d)(1)(i)(A) and its analysis of the URP ''[i]n determining whether the State's goal for visibility improvement provides for reasonable progress.'' 40 CFR 51.308(d)(1)(iii). As explained in the preamble to the RHR, the URP analysis was adopted to ensure that States use a common analytical framework and to ensure an informed and equitable decision making process to ensure a transparent process that would, among other things, ensure that the public would be provided with the information necessary to understand the emission reductions needed, the costs of such measures, and other factors associated with improvements in visibility. 64 FR at 35733. The preamble to the Rule (64 FR 35732) also makes clear that the URP does not establish a ''safe harbor'' for the State in setting its progress goals:

> If the State determines that the amount of progress identified through the [URP] analysis is reasonable based upon the statutory factors, the State should identify this amount of progress as its reasonable progress goal for the first long-term strategy, unless it determines that additional progress beyond this amount is also reasonable. If the State determines that additional progress is reasonable based on the statutory factors, the State should adopt that amount of progress as its goal for the first long-term strategy.

In establishing its RPGs for 2018 for the 20% worst days, ADEQ relied on the improvements in visibility that are anticipated to result from federal, State, and local control programs that are either currently in effect or with mandated future-year emission reduction schedules that predate 2018, including BART emission limitations established by ADEQ. Based on the emissions reductions from these measures, CENRAP modeled the projected visibility conditions anticipated at each Class I area in 2018 and ADEQ used these results to establish RPGs.

ADEQ argued that because this rate of progress, if sustained, will result in a return to natural visibility prior to 2064, no additional analysis was required and would be an unnecessary exercise. We consistently informed States, including Arkansas, throughout the regional haze development process that the above interpretation of the statute and our regulations is incorrect. ADEQ cannot rely solely on meeting the URP to justify

[20] The TSD for CENRAP Emissions and Air Quality Modeling to Support RH State Implementation is found in Appendix 8.1 of the Arkansas RH SIP.

the conclusion that its goals provide for reasonable progress. We provided comments to ADEQ on the draft Arkansas RH SIP to that effect.[21]

States do have discretion in setting RPGs, but are required to go beyond the URP analysis in establishing RPGs. ADEQ made no attempt to determine whether additional progress would be reasonable based on the statutory factors. It does not appear that such an analysis would have been an unnecessary exercise, as claimed by ADEQ. As discussed in section IV.D.2 of this proposed rulemaking, there are at least two point sources in Arkansas not subject to the BART requirements that contribute to visibility impairment at Arkansas' Class I areas. This conclusion is based on the information in the RH SIP indicating that these sources have predicted impacts exceeding the 0.5 dv threshold ADEQ used to determine whether BART sources contribute to visibility impairment. Given their contribution to visibility impairment, these two sources are potential candidates for emissions controls under reasonable progress, as may be other Arkansas point sources whose visibility impact was not evaluated by ADEQ. Also, as discussed in section IV.E.3 of this proposed notice, Arkansas sources are projected to remain significant contributors to visibility impairment in 2018 and thus providing further support that additional analysis should have been performed according to the statutory factors.

Given that ADEQ did not provide an analysis that considered the four statutory factors under 40 CFR 51.308(d)(1)(i)(A) to evaluate the potential of controlling certain sources or source categories for addressing visibility impacts from man-made sources, it is not possible to assess whether any additional control measures for improving visibility are reasonable. Section 51.308(d)(1)(iii) requires that in determining whether the State's goal for visibility improvement provides for reasonable progress towards natural visibility conditions, the Administrator will evaluate the demonstrations developed by the State pursuant to paragraphs (d)(1)(i) and (d)(1)(ii) of this section. Consequently, for the reasons outlined above, we are proposing to find that Arkansas has not satisfied the requirements to establish reasonable progress goals under section 51.308(d)(1)(i)(A).

3. Reasonable Progress Consultation

ADEQ worked with the Missouri Department of Natural Resources (MDNR) and CENRAP to jointly develop the consultation strategy. Consultations were held jointly by Arkansas and Missouri. ADEQ used CENRAP as the main vehicle for facilitating collaboration with FLMs and other states in developing its RH SIP. ADEQ was able to use CENRAP generated products, such as regional photochemical modeling results and visibility projections, and source apportionment modeling to assist in identifying neighboring states' contributions to the visibility impairment at Caney Creek and Upper Buffalo.

ADEQ determined that in addition to Arkansas, the following states have a significant contribution to decreased visibility in one or both of Arkansas' Class I areas: Illinois, Indiana, Kentucky, Missouri, Ohio, Oklahoma, Tennessee, and Texas. ADEQ sent a letter dated February 26, 2007, to these states, requesting that they participate in the consultation process for the Arkansas RH SIP. These states complied with ADEQ's request and participated in the consultation process for the Arkansas RH SIP. ADEQ and MDNR jointly conducted three consultations in the form of conference calls on April 3, May 11, and June 7, 2007. Participants in the consultation process included states and tribes, CENRAP and other Regional Planning Organizations (RPOs), EPA, and FLMs.

At the three consultations held by ADEQ and MDNR, a URP was developed for each Class I area in Arkansas and Missouri (Caney Creek and Upper Buffalo in Arkansas, and Hercules Glades and Mingo in Missouri). The participating states also determined that regional modeling and other findings based on existing and proposed controls arising from local, state, and federal requirements indicated that the two Class I areas in Arkansas and the two Class I areas in Missouri are on the glidepath and are expected to meet the rate of progress goals for the first implementation period ending in 2018. ADEQ determined that additional emissions reductions from other States are not necessary to address visibility impairment at Caney Creek and the Upper Buffalo for the first implementation period ending in 2018, and all states participating in its consultations agreed with this. Therefore, we are proposing to find that Arkansas has satisfied the requirement under section 308(d)(1)(iv) to consult with other States which may reasonably be anticipated to cause or contribute to visibility impairment at Arkansas' two Class I areas.

D. Evaluation of Arkansas' BART Determinations

Arkansas' RH Rule, APC&E Commission Regulation 19, chapter 15, was included in the Arkansas RH SIP submittal, and became effective on October 15, 2007. On August 3, 2010, we received a SIP revision from ADEQ containing amendments to several chapters of APC&E Commission Regulation 19, including Chapter 15. The revisions to Chapter 15 of APC&E Commission Regulation 19, contained in the August 3, 2010 submittal, are mostly non-substantive amendments to the rule we received on September 23, 2008. Chapter 15 of Regulation 19 incorporates by reference the definitions contained in section 40 CFR 51.301 of the Act, as in effect on June 22, 2007. Chapter 15 also identifies the Arkansas BART-eligible sources, the subject to BART sources and their BART requirements, and the BART compliance provisions. The rules further provide that the source's air quality permit be revised to incorporate the resulting source-specific requirements. The State's RH Rule and our proposed action on it are discussed in section IV.D.4 of this proposed rulemaking.

BART is an element of Arkansas' LTS for the first implementation period. As discussed in more detail in section III.D. of this preamble, the BART evaluation process consists of three components: (1) An identification of all the BART-eligible sources, (2) an assessment of whether those BART-eligible sources are in fact subject to BART and (3) a determination of any BART controls. ADEQ addressed these steps as follows:

1. Identification of BART–Eligible Sources

The first step of a BART evaluation is to identify all the BART-eligible sources within the state's boundaries. ADEQ identified the BART-eligible sources in Arkansas by utilizing the three eligibility criteria in the BART Guidelines (70 FR 39158) and our regulations (40 CFR 51.301): (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 was in existence on August 6, 1977; and (3) potential emissions of any visibility-impairing pollutant from subject units are 250 tons or more per year. ADEQ initially screened its emissions inventory and permitting database to identify major facilities with emission units in one or more of the 26 BART source categories. Following this, ADEQ used its databases

[21] See Appendix 2.1 of the Arkansas RH SIP

and records to identify facilities in these source categories with potential emissions of 250 tons per year (tpy) or more of the following visibility impairing pollutants: sulfur dioxide (SO_2), nitrogen dioxide (NO_X), particulate matter equal to or smaller than ten microns (PM_{10}), volatile organic compounds (VOC) or ammonia (NH_3). Using its databases and records, ADEQ then determined which of these facilities had units that were in existence on August 7, 1977 and began operation after August 7, 1962. ADEQ contacted the sources, when necessary, to obtain or confirm this information. From this, ADEQ determined there are 18 facilities with BART-eligible units. Table 2 lists Arkansas' BART-eligible sources, as identified by Arkansas in Table 9.1 of the RH SIP:

TABLE 2—FACILITIES WITH BART-ELIGIBLE UNITS IN ARKANSAS

BART source category	Facility name	County	Unit description
Fossil fuel-fired steam electric plants of more than 250 MMBTU/hr heat input.	AEP Flint Creek Power Plant	Benton	Boiler
	AECC Carl E. Bailey Generating	Woodruff	Boiler
	AECC John L. McClellan Generating	Ouachita	Boiler
	Entergy Lake Catherine Plant	Hot Spring	Unit 4 Boiler
	Entergy Robert E. Ritchie Plant	Phillips	Unit 2
	Entergy White Bluff Plant	Jefferson	Unit 1
			Unit 2
			Auxiliary Boiler
Kraft pulp mills	Domtar Ashdown Mill	Little River	No. 1 Power
			No. 2 Power
	Delta Natural Kraft	Jefferson	Recovery Boiler
	Evergreen Packaging/International	Jefferson	No. 4 Recovery
	Georgia-Pacific Crossett Mill	Ashley	9A Boiler
	Green Bay Packaging	Conway	Recovery Boiler
	Potlatch Forest Products/Clearwater	Desha	Power Boiler
Petroleum	Lion Oil Company	Union	No. 7 Catalyst
Sulfur recovery	Albermarle Corporation South Plant	Columbia	Tail Gas
Sintering plants	Big River Industries—Arkalite	Crittenden	Kiln A
Chemical process plants	Albermarle Corporation South Plant	Columbia	No. 1 Boiler
			No. 2 Boiler
	Future Fuels/Eastman Chemical	Independence	3 Coal Boilers
	El Dorado Chemical Company	Union	West Nitric Acid
			East Nitric Acid
			Nitric Acid

We note that in chapter 15 of APC&E Regulation 19, contained in the RH SIP submittal we received on September 23, 2008, and as revised by the submittal we received on August 3, 2010, ADEQ identified one more unit (not listed in Table 2), the 6A Boiler at the Georgia-Pacific Crossett Mill, as being BART-eligible. ADEQ did not identify the 6A Boiler as BART-eligible in the RH SIP narrative. Appendix 9.1A states the 6A Boiler began operation prior to August 7, 1962, and that it falls out of the BART eligibility criteria because of its start of operations date. On September 27, 2011, ADEQ submitted supplemental information clarifying that the Georgia-Pacific Crossett Mill provided ADEQ a copy of a boiler inspection report for the 6A Boiler, which states that the inspection of the new boiler took place on August 6, 1962, to determine if the boiler complied with the State and American Society of Mechanical Engineers (ASME) codes.[22] However, ADEQ stated it cannot say with certainty whether the 6A boiler was in operation as of August 6, 1962, or at a later date.[23] Since there is not sufficient

[22] A copy of the boiler inspection report for the 6A Boiler at the Georgia-Pacific Crossett Mill can be found in the docket for this proposed rulemaking.

[23] The BART Guidelines define ''in operation'' as ''engaged in activity related to the primary design function of the source.''

information to determine the date of start of operations of the 6A Boiler, we cannot make the determination that the boiler is not BART-eligible. Therefore, we are proposing to find that the 6A Boiler at the Georgia-Pacific Crossett Mill is BART-eligible.

In the RH SIP, ADEQ identified one unit (the No. 4 recovery boiler) at International Paper/Evergreen Packaging as BART-eligible (shown in Table 2). ADEQ included two other units (the No. 1 and 2 Power Boilers) at International Paper/Evergreen Packaging in its evaluation to determine what sources are subject to BART. The International Paper/Evergreen Packaging No. 1 and No. 2 Power Boilers are not BART-eligible because they were constructed and were in operation prior to August 7, 1962.[24] We agree that the No. 1 and 2 Power Boilers at International Paper/Evergreen Packaging are not BART-eligible.

In the RH SIP, ADEQ did not identify Boilers SN–301A and SN–302A at the Great Lakes Chemical Plant as BART-eligible, but since these units were at one point believed to be BART-eligible, ADEQ included these units in its evaluation to determine what sources are subject to BART. EPA reviewed the federally enforceable operating permit for the Great Lakes Chemical Plant and determined that Boilers SN–301A and SN–302A are not BART-eligible because they are boilers with a heat input rating less than 250 MMBtu/hr and are not integral to the process, as the permit states they are used to supply heat to the process.[25] The BART Guidelines provide that an individual fossil fuel boiler smaller than 250 MMBtu/hr that does not fall into source Category 1 (*i.e.,* Fossil-fuel fired steam electric plants of more than 250 MMBtu/hr heat input), falls into one of the other source categories for BART eligibility only if it is an integral part of a process description at a plant. If the boiler is integral to the process description at a plant, it falls into the source category of the process which it serves. In general, if the boiler serves the process in any way beyond contributing heat, it is integral to the process. Based on information in the current operating air permit for the Great Lakes Chemical Plant, we agree that Boilers SN–301A and SN–302A are not BART-eligible.

As discussed above, there is a discrepancy between the BART-eligible sources identified in the RH SIP narrative, and those identified in the State's RH Rule. Because ADEQ submitted supplemental information on September 27, 2011, clarifying that it did not know with certainty the startup date of operations of the 6A Boiler at the Georgia-Pacific Crossett Mill, we are proposing to find that the 6A Boiler is BART-eligible. We are proposing to approve ADEQ's identification of the remaining BART-eligible sources.

2. Identification of Sources Subject to BART

The second step of the BART evaluation is to identify those BART-eligible sources that may reasonably be anticipated to cause or contribute to visibility impairment at any Class I area, i.e. those sources that are subject to BART. The BART Guidelines allow states to consider exempting some BART-eligible sources from further BART review because they may not reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area. Consistent with the BART Guidelines, ADEQ required each of its BART-eligible sources to develop and submit dispersion modeling to assess the extent of their contribution to visibility impairment at surrounding Class I areas.

The BART Guidelines direct states to address SO_2, NO_X and direct PM (including both PM_{10} and $PM_{2.5}$) emissions as visibility-impairing pollutants, and States must exercise their ''best judgment to determine whether VOC or ammonia emissions from a source are likely to have an impact on visibility in an area.'' *See* 70 FR 39162. CENRAP modeling demonstrated that VOCs from anthropogenic sources are not significant visibility-impairing pollutants at Caney Creek and Upper Buffalo. Ammonia emissions in Arkansas are primarily due to area sources, such as livestock and fertilizer application. Because these are not point sources, they are not subject to BART. The emissions inventory prepared for the CENRAP modeling demonstrates that ammonia from point sources are not significant visibility-impairing pollutants in Arkansas. ADEQ further argued that only specific VOCs form secondary organic aerosols that affect visibility and that these compounds are a fraction of the total VOCs reported in Arkansas' emissions inventory. ADEQ does not have the breakdown of VOC emissions necessary to model only those that impair visibility. Because CALPUFF, EPA's prescribed screening model, cannot simulate formation of particles from anthropogenic VOCs, nor their visibility impacts, ADEQ did not evaluate emissions of VOCs in making BART determinations. We have reviewed this information and propose to agree with ADEQ's decision to address only SO_2, NO_X, and PM as visibility impairing pollutants because VOC emissions from anthropogenic sources are not significant visibility-impairing pollutants at Caney Creek and Upper Buffalo and ammonia emissions in Arkansas are primarily due to area sources.

a. Modeling Methodology

The BART Guidelines provide that states may choose to use the CALPUFF[26] modeling system or another appropriate model to predict the visibility impacts from a single source on a Class I area and to therefore, determine whether an individual source is anticipated to cause or contribute to impairment of visibility in Class I areas, *i.e.,* ''is subject to BART''. The Guidelines state that we believe CALPUFF is the best regulatory modeling application currently available for predicting a single source's contribution to visibility impairment (70 FR 39162). ADEQ used the CALPUFF modeling system to determine whether individual sources in Arkansas were subject to or exempt from BART.

The BART Guidelines also recommend that states develop a modeling protocol for making individual source attributions, and suggest that states may want to consult with us and their RPO to address any issues prior to modeling. The CENRAP states, including Arkansas, developed the ''CENRAP BART Modeling Guidelines''.[27] Stakeholders, including

[24] On May 27, 1958, the Arkansas Department of Labor performed an annual inspection of the International Paper No. 1 and 2 Boilers. On June 26, 1958, the Arkansas Department of Labor issued an inspection certificate to the International Paper Company for the No. 1 and 2 Boilers. Since the No. 1 and 2 Boilers were in operation prior to August 7, 1962, they fall out of the startup date criteria for BART eligibility. The inspection certificate for the can be viewed in the docket for this proposed rulemaking.

[25] ADEQ Operating Air Permit for the Great Lakes Chemical Corporation—Central Plant (Permit No. 1077–AOP–R1). This permit can be viewed at *http://www.adeq.state.ar.us/ftproot/pub/WebDatabases/PermitsOnline/Air/1077-AOP-R1.pdf.*

[26] Note that our reference to CALPUFF encompasses the entire CALPUFF modeling system, which includes the CALMET, CALPUFF, and CALPOST models and other pre and post processors. The different versions of CALPUFF have corresponding versions of CALMET, CALPOST, etc. which may not be compatible with previous versions (*e.g.,* the output from a newer version of CALMET may not be compatible with an older version of CALPUFF). The different versions of the CALPUFF modeling system are *available* from the model developer at *http://www.src.com/verio/download/download.htm.*

[27] CENRAP BART Modeling Guidelines, T. W. Tesche, D. E. McNally, and G. J. Schewe (Alpine Geophysics LLC), December 15, 2005, *available* at *http://www.deq.state.ok.us/aqdnew/RulesAndPlanning/Regional_Haze/SIP/Appendices/index.htm.*

EPA, FLMs, industrial sources, trade groups, and other interested parties, actively participated in the development and review of the CENRAP protocol. CENRAP provided readily available modeling data bases for use by states to conduct their analyses. We note that the original meteorological databases generated by CENRAP did not include observations as EPA guidance recommends, therefore sources were evaluated using the 1st High values instead of the 8th High values. The use of the 1st High modeling values was agreed to by EPA, representatives of the Federal Land Managers, and CENRAP stakeholders. We are proposing to find the chosen model and the general modeling methodology for screening modeling acceptable.

b. Contribution Threshold

For states using modeling to determine the applicability of BART to single sources, the BART Guidelines note that the first step is to set a contribution threshold to assess whether the impact of a single source is sufficient to cause or contribute to visibility impairment at a Class I area. The BART Guidelines state that, ''[a] single source that is responsible for a 1.0 deciview change or more should be considered to 'cause' visibility impairment.'' 70 FR 39104, 39161. The BART Guidelines also state that ''the appropriate threshold for determining whether a source contributes to visibility impairment may reasonably differ across states,'' but, ''[a]s a general matter, any threshold that you use for determining whether a source 'contributes' to visibility impairment should not be higher than 0.5 deciviews.'' *Id.* Further, in setting a contribution threshold, states should ''consider the number of emissions sources affecting the Class I areas at issue and the magnitude of the individual sources' impacts. The Guidelines affirm that states are free to use a lower threshold if they conclude that the location of a large number of BART-eligible sources in proximity of a Class I area justifies this approach. Considering the number of sources affecting Arkansas' Class I areas and the magnitude of each source's impact, ADEQ used a contribution threshold of 0.5 dv for determining which sources are subject to BART. We agree with the State's selection of this threshold value.

c. Sources Identified by ADEQ as Subject to BART

Following the elimination of those sources that were found to have visibility impacts well below the 0.5 dv threshold, ADEQ identified the sources contained in Table 3 as being subject to BART.

TABLE 3—SOURCES IN ARKANSAS SUBJECT TO BART

Facility name	BART emission units	Source category	Pollutants evaluated
AECC Carl E. Bailey Generating Station	Unit 1	fossil fuel-fired steam electric plants	SO_2
			NO_X
			PM_{10}
AECC John L. McClellan Generating Station.	Unit 1	fossil fuel-fired steam electric plants	SO_2
			NO_X
			PM_{10}
AEP Flint Creek Power Plant	Boiler No. 1	fossil fuel-fired steam electric plants	SO_2
			NO_X
			PM_{10}
Entergy Lake Catherine Plant	Unit 4	fossil fuel-fired steam electric plants	SO_2
			NO_X
			PM_{10}
Entergy White Bluff Plant	Units 1, 2, and Auxiliary Boiler	fossil fuel-fired steam electric plants	SO_2
			NO_X
			PM_{10}
Domtar Ashdown Mill	Power Boilers No. 1 and 2	kraft pulp mill	SO_2
			NO_X
			PM_{10}

In Appendix 9.2B of the RH SIP, ADEQ provided screening modeling results for all sources identified in the RH SIP as BART-eligible sources, as well as for the SN–301A and SN–302A Boilers at the Great Lakes Chemical plant, the No. 1 and No. 2 Power Boilers at International Paper/Evergreen Packaging, and the 6A and 9A Boilers at the Georgia-Pacific Crossett Mill (as discussed above). Our evaluation of these results showed that four facilities that ADEQ did not identify as subject to BART had modeled visibility impacts that exceed the 0.5 dv contribution threshold used by ADEQ to determine what sources are subject to BART. Our evaluation to determine whether these sources are subject to BART or not is discussed below:

- As discussed in section V.D.1., ADEQ included the No. 1 and No. 2 Power Boilers at International Paper/Evergreen Packaging and the SN–301A and SN–302A Boilers at the Great Lakes Chemical plant in its modeling evaluation to determine what sources are subject to BART. As already discussed elsewhere in this proposed notice, we are proposing to approve ADEQ's identification of these two sources as not BART-eligible and not subject to BART.
- As discussed in section IV.D.2.a. of this proposed rulemaking, the original meteorological databases generated by CENRAP did not include observations as EPA guidance recommends. Therefore, in their evaluation to determine if a source exceeds the 0.5 dv contribution threshold at nearby Class I areas, states used the 1st high values (*i.e.*, maximum value) of modeled visibility impacts instead of the 8th high values (*i.e.*, 98th percentile value). The use of the 1st high modeled values was agreed to by EPA, representatives of the Federal Land Managers, and CENRAP stakeholders. ADEQ's modeling shows that Future Fuels/Eastman Chemical has a modeled visibility impact of 0.711 dv at Hercules-Glade. Further examination of the modeling results reveals that only one day of the three years modeled exceeds the 0.5 dv contribution threshold value at any Class I area. Since only one day is projected above the threshold, we believe it is very unlikely that a refined modeling approach using updated meteorological data, which would allow for the use of the 98th percentile modeled visibility impact rather than the maximum impact, would show modeled impacts above the threshold. Therefore, we are proposing that this facility is not subject to BART.
- The visibility modeling provided in Appendix 9.2B of the Arkansas RH SIP shows that the 9A Boiler of the Georgia-Pacific Crossett Mill has visibility impacts exceeding the 0.5 dv contribution threshold, with a visibility impact above 1 dv at Caney Creek and Hercules-Glade. EPA also reviewed ADEQ's revised modeling for this source, which looked at the visibility impacts of both the 6A and 9A Boilers at the Georgia-Pacific Crossett Mill. Using updated emission rates, ADEQ's revised modeling showed projected visibility impacts of the two boilers combined below the 0.5 dv threshold. The revised emission rates were based on stack test results and assumptions based on worst case monthly fuel usage, from the perspective of total emissions. However, from the data provided, it is unclear if the modeled emissions are representative of the actual maximum 24 hour emissions from the highest emitting day over the modeled period. There is no supporting technical analysis discussing the assumptions made in the revised emission estimates and explaining how stack test data was used to estimate maximum emissions nor is fuel usage information provided for the modeled period. We are proposing to disapprove ADEQ's determination that the Georgia-Pacific Crossett Mill's 6A and 9A Boilers are not subject to BART because ADEQ has not modeled the visibility impact of the 6A and 9A Boilers using acceptable estimates of maximum 24 hour emissions, and as a result we do not know if the boilers have a combined visibility impact below the 0.5 dv contribution threshold or not. Based on the permit allowables and available information, the two boilers are subject to BART and require a full BART analysis.

We are proposing to approve ADEQ's identification of subject to BART sources, except for ADEQ's determination that the Georgia-Pacific Crossett Mill 6A and 9A Boilers are not subject to BART.

3. BART Determinations

The third step of a BART evaluation is to perform the BART analysis. BART is a source-specific control determination, based on consideration of several factors set out in section 169A(g)(2) of the CAA. These factors include the costs of compliance and the degree of improvement in visibility associated with the use of possible control technologies. EPA issued BART Guidelines (Appendix Y to Part 51) in 2005 to clarify the BART provisions based on the statutory and regulatory BART requirements (70 FR 39164). The BART Guidelines describe the BART analysis as consisting of the following five basic steps:

- 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.

We note the BART Guidelines (Appendix Y to part 51) provide that states must follow the guidelines in making BART determinations on a source-by-source basis for 750 MW power plants but are not required to use the process in the guidelines when making BART determinations for other types of sources. States with subject to BART units with a generating capacity less than 750 MW are strongly encouraged to follow the BART Guidelines in making BART determinations, but they are not required to do so. However, the requirement to perform a BART analysis that considers ''the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology,'' is found in section 51.308(e)(1)(ii)(A) and the RHR, and applies to all subject to BART sources.

All of the sources that are subject to BART presented in Table 3 are fossil fuel fired electricity generating units, with the exception of the Domtar Ashdown Mill, which is a kraft pulp mill. ADEQ performed BART determinations for these sources for NOx, SO_2, and PM.

We have found several problems in these BART determinations, which lead us to propose disapproval of some of ADEQ's BART determinations. We discuss these problems in detail in the individual BART determination sections, and we summarize some general issues in the paragraphs that follow.

For some sources, ADEQ did not adequately consider whether retrofit controls should be required based on a flawed analysis of the source's potential visibility impacts. ADEQ assumed that if pre-control modeling [28] conducted on the basis of a single pollutant showed that the source's emissions of the pollutant in question did not ''contribute'' to visibility impairment, then further BART analysis for that pollutant was unnecessary. This approach is unacceptable. Due to the nonlinear nature and complexity of atmospheric chemistry and chemical transformation among pollutants, ideally all relevant pollutants should be modeled together to predict the total visibility impact at each Class I area receptor.[29] At a minimum, NO_X and SO_2

[28] Throughout this document, any reference to ''ADEQ modeling'' refers to modeling performed or reviewed by ADEQ.

[29] Memo from Joseph Paisie (Geographic Strategies Group, OAQPS) to Kay Prince (Branch Chief EPA Region 4) on Regional Haze Regulations

emissions should be modeled together to determine the visibility impacts attributable to these pollutants when evaluating controls and combinations of controls in determining BART for a source. Predicting the impacts of PM on visibility is relatively straight-forward, unlike predicting the impacts of SO_2 and NO_X. Using CALPUFF on a pollutant specific basis to model only the impact of PM emissions on visibility is an acceptable approach to determine whether a source should be subject to review for PM controls, or alternatively, that the source is not subject to BART for PM. ADEQ applied a threshold of 0.5 dv for determining whether a source ''contributes'' to visibility impairment on a per-pollutant basis. As discussed above, the State selected a threshold of 0.5 dv for the initial screening modeling that included all pollutants. Clearly, a lower threshold value is needed in evaluating pollutant-specific modeling for sources that emit more than one visibility impairing pollutant. Furthermore, this approach is only acceptable for PM-specific modeling. We note that a State may establish *de minimis* levels of emissions (applicable on a plant-wide basis) of visibility impairing pollutants to exclude some sources from further evaluation when the emissions are so minimal that they are unlikely to contribute to regional haze.[30]

For some BART determinations, ADEQ did not properly determine BART, but instead concluded that the presumptive limits in the BART Guidelines could be adopted in place of a careful source-specific analysis of the appropriate level of controls. As noted above, EPA issued BART Guidelines in 2005 that address the BART determination process by laying out a step by step process for taking into consideration the factors relevant to a BART determination. In that rulemaking, EPA also established presumptive BART limits for certain electric generating units (EGUs) located at power plants 750 MW or greater in size based variously on the size of the unit, the type of unit, the type of fuel used, and the presence or absence of controls.[31] Having identified controls that the Agency considered to be generally cost-effective across all affected units, the EPA took into account the substantial degree of visibility improvement anticipated to result from the use of such controls on these EGUs and concluded that such BART-eligible sources should at least meet the presumptive limits. The presumptive limits accordingly are the starting point in a BART determination for these units—unless the State determines that the general assumptions underlying EPA's analysis are not applicable in a particular case. EPA did not provide that States could avoid a source-specific BART determination by adopting the presumptive limits. In fact, nothing on the record would support the conclusion that the presumptive limits represent the ''best available retrofit controls'' for all EGUs at these large power plants. EPA did not address the question of whether in specific cases more stringent controls would be called for but rather simply concluded that it could not reach a generalized conclusion as to the appropriateness of more stringent controls for categories of EGUs. As a result, the BART Rule does not establishing a ''safe harbor'' from more stringent regulation under the BART provisions. We have consistently informed ADEQ in comments to its draft SIP and in conversations that foregoing a BART analysis is not acceptable.

For the BART determinations for which ADEQ did perform a full BART analysis that considered the statutory factors under section 51.308(e)(1)(ii)(A), we are proposing to find that ADEQ did not adequately consider one or more of the factors it is required to consider in determining whether retrofit controls should be required.

For more details, please see our evaluation of the BART determination for each subject to BART unit, below, and the TSD.

a. AECC Bailey Unit 1 and AECC McClellan Unit 1 BART Determinations

The AECC Bailey Unit 1 and the AECC McClellan Unit 1 are BART-eligible sources. The AECC Bailey Unit 1 is a boiler with a gross output of 122 MW and a maximum heat input rate of 1350 MMBtu/hr, and is currently permitted to burn both natural gas and fuel oil. The fuel oil burned at the plant is subject to an operating air permit sulfur content limit of 2.3% by weight. The AECC McClellan Unit 1 is a boiler with a gross output of 134 MW and a maximum heat input rate of 1436 MMBtu/hr, and is currently permitted to burn both natural gas and fuel oil. The fuel oil burned at the plant is subject to an operating air permit sulfur content limit of 2.8% by weight.

Regarding BART for NO_X and PM, ADEQ conducted pollutant specific pre-control CALPUFF[32] modeling for the AECC Bailey Unit 1 and the AECC McClellan Unit 1. AECC stated that the results of the NO_X modeling show that NO_X does not cause or contribute to visibility impacts.[33] Based on this, AECC determined and ADEQ agreed it was not necessary to make a BART determination for NO_X for either the AECC Bailey Unit 1 or AECC McClellan Unit 1. However, the ADEQ's modeling results presented indicate that the predicted visibility impacts from NO_X are as high as 0.347 dv at Mingo due to emissions from the AECC Bailey Unit 1, and 0.421 dv at Caney Creek due to emissions from the AECC McClellan Unit 1. As stated above, NO_X and SO_2 emissions should be modeled together due to the nonlinear nature and complexity of atmospheric chemistry and chemical transformation among pollutants. Evaluation of the screening modeling results for these units reveals that on some of the most impacted days, NO_X is a significant contributor to the visibility impairment due to these units. Post-control modeling performed by ADEQ, applying the use of 1% sulfur fuel, show that these units would continue to cause or contribute to visibility impairment at a number of Class I areas, with NO_X emissions responsible for over 50% of the impairment on some days under this control scenario. In light of the relatively high impacts due to NO_X, a combination of NO_X and SO_2 controls may prove to be cost-effective and provide for substantial visibility improvement and should therefore be evaluated.

For PM BART, AECC decided and ADEQ agreed that PM does not cause visibility impacts because the PM emissions are less than those of NO_X at these units. This conclusion is not supported in the record by PM visibility modeling results, additional technical analysis, or reference to a permit limit for PM that restricts emissions below a level that will impact visibility. Neither the State nor AECC have completed a BART analysis that considers the

and Guidelines for Best Available Retrofit Technology (BART) Determinations, July 19, 2006.

[30] ''States may choose to identify de minimis levels of pollutants at BART-eligible sources (but are not required to do so). De minimis values should be identified with the purpose of excluding only those emissions so minimal that they are unlikely to contribute to regional haze. Any de minimis values that you adopt must not be higher than the PSD applicability levels: 40 tons/yr for SO_2 and NO_X and 15 tons/yr for PM_{10}. These de minimis levels may only be applied on a plant-wide basis.'' 40 CFR Appendix Y to part 51.

[31] 70 FR at 39131–39136.

[32] The CALPUFF modeling system consists of a meteorological data pre-processor (CALMET), an air dispersion model (CALPUFF), and post-processor programs (POSTUTIL, CALSUM, CALPOST). The CALPUFF modeling system is the recommended model for conducting BART visibility analysis.

[33] Arkansas Electric Cooperative Corporation Best Available Retrofit Technology Engineering Analysis prepared by Stephen Cain, October 20, 2006.

statutory factors under section 51.308(e)(1)(ii)(A) that states are required to consider in determining what type and level of control is BART for a source for NO_X and PM, or fully demonstrated that these units have sufficient pollution controls in place for these pollutants such that additional controls would likely achieve very low emissions reductions, have minimal visibility benefit, and not be cost-effective. Therefore, we are proposing to disapprove the NO_X and PM BART determinations for these two units.

Regarding BART for SO_2 for the two sources, AECC performed a BART analysis to determine what retrofit controls are BART for AECC Bailey Unit 1 and AECC McClellan Unit 1. In Step 1 of this BART analysis, AECC identified use of fuel oil with 1% sulfur content and installation of a scrubber as the only two control options available. This is a problem because 1% sulfur fuel oil is not the maximum level of control available when it comes to the use of low sulfur fuel as a control strategy for SO_2 emissions. After completing the remaining steps of the BART analysis, AECC determined and ADEQ agreed that BART for the AECC Bailey Unit 1 and the AECC McClellan Unit 1 is use of fuel oil with 1% sulfur content. Our evaluation of AECC's BART analysis beyond Step 1 can be found in the TSD. We are not discussing in this proposed notice our evaluation of AECC's BART analysis for the AECC Bailey Unit 1 and the AECC McClellan Unit 1 beyond Step 1, as we are proposing that AECC did not properly complete the first step of the BART analysis and thus we find that AECC and ADEQ did not properly follow the requirements of section 51.308(e)(1)(ii)(A) in determining BART. Specifically, we are proposing that AECC and ADEQ did not properly ''take into consideration the technology available'' by failing to consider the maximum level of control each control option is capable of achieving. The BART Guidelines (Appendix Y to Part 41) provide that in identifying all options, you must identify the most stringent option (*i.e.,* maximum level of control each technology is capable of achieving) as well a reasonable set of options for analysis. The requirement to consider the most stringent level of control when making BART determinations is also found in the RHR (64 FR 35740), which provides that in establishing source specific BART emission limits, the State should identify and consider in the BART analysis the maximum level of emission reduction that has been achieved in other recent retrofits at existing sources in the source category. The visibility regulations define BART as ''an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction.'' Since recent retrofits at existing sources provide a good indication of the current ''best system'' for controlling emissions, these controls must be considered in the BART analysis. In considering use of fuel oil with low sulfur content as a control option in the BART analysis, AECC did not identify and consider the maximum level of control achievable from the use of low sulfur fuel oil, and thus the BART analysis is flawed.

Sulfur content in fuel oil currently can be found in industry to be 0.5% by weight or less. AECC should have considered the use of fuel oil with 0.5% sulfur content or less in the BART analysis for the two units in question. We are aware of several fossil-fuel fired steam electric plants throughout the country that are currently limited by permit to burn fuel oil with a sulfur content of 0.5% or less by weight. Connecticut limits the sulfur content of fuel oil to a maximum 0.3% [34] and New York requires facilities to comply with the use of fuel oil with varying sulfur content limits, with facilities in New York City being required to use fuel oil with a maximum 0.3% sulfur content.[35] Lowering the sulfur content in fuel oil is also a part of the long-term strategy recommended by the Mid-Atlantic/Northeast Visibility Union (MANE–VU) states to reduce and prevent regional haze.[36] The MANE–VU states in the inner zone (New Jersey, New York, Delaware, and Pennsylvania) plan to reduce the sulfur content of No. 6 residual fuel oil to 0.3–0.5% sulfur by weight by no later than 2012.[37] Therefore, the use of fuel oil with a 0.5% sulfur content or lower is technically feasible and either AECC or ADEQ should have evaluated its cost effectiveness for the AECC Bailey Unit 1 and the AECC McClellan Unit 1. In addition, an operating air permit restriction to use only natural gas as the fuel source for the two units would have also been acceptable. As part of the BART analysis, ADEQ and/or AECC must perform a cost analysis in which all cost estimates are properly documented and must evaluate the visibility impacts of all technically feasible control options considered before making a BART determination.

Therefore, for the reasons expressed above, we are proposing to disapprove the SO_2, NO_X, and PM BART determinations for the AECC Bailey Unit 1 and the AECC McClellan Unit 1.

b. AEP Flint Creek No. 1 Boiler BART Determination

The AEP Flint Creek No. 1 Boiler is a BART-eligible source. The unit has a gross output of 558 MW and a maximum heat input rate of 6324 MMBtu/hr, and burns primarily low sulfur western coal, but can also combust fuel oil and tire derived fuels (TDF). Fuel oil firing is only allowed during startup and shutdown of the boiler, startup and shutdown of the pulverizer mills, for flame stabilization when the coal is frozen, for fuel oil tank maintenance, to prevent boiler tube failure in extreme cold weather, and when the unit is offline for maintenance.

Regarding BART for PM, ADEQ conducted pre-control CALPUFF modeling for the AEP Flint Creek No. 1 Boiler showing that PM_{10} and $PM_{2.5}$ emissions from the source have minimal visibility impacts at each Class I area within 300 km. Based on this, AEP decided and ADEQ agreed that the existing PM emission limit in the operating air permit, which is achievable through the use of the existing electrostatic precipitator (ESP), is BART for PM for AEP Flint Creek No. 1 Boiler. We reviewed the CALPUFF visibility modeling submitted by ADEQ for AEP Flint Creek No. 1 Boiler, and agree that PM_{10} and $PM_{2.5}$ emissions from the source have minimal visibility impacts at each Class I area within 300 km. As explained in section IV.D.3 of this proposed rulemaking, using CALPUFF on a pollutant specific basis to model only the impact of PM emissions on visibility is an acceptable approach to determine whether a source should be subject to review for PM controls. In the case of the AEP Flint Creek No. 1 Boiler, we have found that the visibility impact due to PM emissions alone is so minimal such that the installation of any additional PM controls on the unit would likely

[34] Connecticut Department of Environmental Protection (DEP). ''22a–174–19a: Control of Sulfur Dioxide Emissions from Power Plants and Other Large Stationary Sources of Air Pollution,'' Regulations of Connecticut State Agencies, Title 22a: Abatement of Air Pollution, December 28, 2000. *http://www.dep.state.ct.us/air2/regs/mainregs/sec19a.pdf.*

[35] New York State Department of Environmental Conservation (DEC). ''Subpart 225–1: Fuel Composition and Use-Sulfur Limitations,'' Environmental Conservation Rules and Regulations, May 8, 2005. *http://www.dec.state.ny.us/website/regs/subpart225_1.html.*

[36] MANE–VU is an RPO that includes the following states: Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Maryland, Delaware, and also the District of Columbia.

[37] *See* 76 FR 27973.

achieve very low emissions reductions, have minimal visibility benefit, and not be cost-effective. Therefore, we are proposing to approve ADEQ's determination that PM BART for AEP Flint Creek No. 1 Boiler is the existing PM emission limit. The federally enforceable operating air permit for the source sets the PM emission limit for the unit at 0.1 lb/MMBtu.[38]

Regarding BART for SO_2 and NO_X, neither AEP nor ADEQ performed a BART analysis that considered the statutory factors states are required to consider in determining what retrofit controls are BART for the AEP Flint Creek No. 1 Boiler. Instead, AEP determined and ADEQ agreed that BART for SO_2 is the presumptive limit of 0.15 lb/MMBtu and that BART for NO_X is the presumptive limit of 0.23 lb/MMBtu for AEP Flint Creek No. 1 Boiler.[39] We are aware that the AEP Flint Creek Power Plant has a 558 MW generating capacity, and is therefore not required to follow the BART Guidelines in making BART determinations for the No. 1 Boiler. However, this facility and/or the State must still conduct a BART analysis as specified in 40 CFR 51.308(e)(1)(ii)(A), which provides that:

> The determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART within the State. In this analysis, the State must take into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

Therefore, we are proposing to disapprove ADEQ's BART finding since neither AEP nor ADEQ conducted a BART analysis considering the best system of controls for BART for SO_2 and NO_X for AEP Flint Creek No. 1 Boiler. The source and/or ADEQ should have performed a BART analysis for SO_2 and NO_X. Controls achieving more than the SO_2 and NO_X presumptive limits are available and should be considered in the BART analysis, especially considering the magnitude of the visibility impact of the AEP Flint Creek No. 1 Boiler on the Class I areas within 300 km.[40] For instance, selective catalytic reduction (SCR) controls are routinely designed and have routinely achieved a NO_X control efficiency of 90% and a NO_X emission rate as low as 0.04 lb/MMBtu,[41] based on a 30-day rolling average. Furthermore, SCR system designers analyzed EPA's Clean Air Market's CEMS data to determine the NO_X levels that are currently being achieved by over 100 SCR-equipped coal-fired boilers, and found that 25 of these units are achieving NO_X emissions less than 0.05 lb/MMBtu on an hourly average basis.[42] Flue gas desulfurization (FGD) units (*i.e.,* wet and dry scrubbers), are a type of post-combustion control for SO_2 emissions. In a report for the National Lime Association, Sargent & Lundy stated that vendors guarantee SO_2 reduction efficiencies of up to 95%, or as low as 0.06 lb/MMBtu SO_2 for dry scrubbers.[43] The Longleaf Energy Station in Georgia has two 600 MW boilers that burn coal and are equipped with a dry scrubber capable of achieving SO_2 emissions of 0.065 lb/MMBtu on a 30-day rolling average when the uncontrolled SO_2 emission rate is less than or equal to 1 lb/MMBtu.[44] The Desert Rock Energy Company, a 1500 MW coal fired power plant in New Mexico, is equipped with a wet scrubber and has an SO_2 emission limit of 0.060 lb/MMBtu, averaged over a 24-hour period.[45] We note that a 24-hour average is much more stringent than a 30-day rolling average.

Therefore, for the reasons expressed above, we are proposing to disapprove ADEQ's determination of SO_2 and NO_X BART for the AEP Flint Creek No. 1 Boiler.

c. Entergy Lake Catherine Unit 4 BART Determination

The Entergy Lake Catherine Unit 4 is a BART-eligible source. Unit 4 is a combustion engineering tilting tangential fired boiler powering a 552 MW generator. The unit has a maximum heat input rate of 5850 MMBtu/hr and burns primarily natural gas with No. 6 fuel oil as the secondary fuel. There is currently no emission control equipment connected to the boiler. Class I areas within 300 km of the facility include Caney Creek, Upper Buffalo, and Hercules Glades.

Since Unit 4 is permitted to burn both natural gas and No. 6 fuel oil, ADEQ made BART determinations for both natural gas firing and fuel oil firing scenarios. The Arkansas RH SIP contains the CALPUFF pre-control modeling files for the natural gas firing scenario, and ADEQ also provided the modeling files for the fuel oil firing scenario. CALPUFF post-control modeling results for both gas and oil firing were also included in the Arkansas RH SIP. In the State's September 27, 2011 supplemental submittal, ADEQ brought to our attention that per an inspection report dated July 28, 2011, Entergy Lake Catherine Unit 4 is no longer capable of burning fuel oil. ADEQ noted that the fuel tanks at the source have been emptied and the pipework necessary to burn fuel oil is in the process of being removed. ADEQ stated the source does maintain the ability to burn natural gas. We note that since the source has not modified its permit and ADEQ has not revised its RH SIP to reflect this change, we are not disregarding the BART emission limits for the source for fuel oil firing in this proposed rulemaking.

Regarding BART for SO_2 and PM for the natural gas firing scenario, Entergy stated that most of the visibility-causing emissions from Unit 4 are due to NO_X since SO_2 and PM emissions from natural gas-fired boilers are generally very low. Therefore, for the natural gas

[38] ADEQ Operating Air Permit for AEP-Flint Creek Power Plan (Permit No. 0276–AOP–R5). This permit can be viewed at *http://www.adeq.state.ar.us/ftproot/pub/WebDatabases/PermitsOnline/Air/0276-AOP-R5.pdf.*

[39] The "presumptive limits" are the rebuttable specific limits established in the BART Rule for SO_2 and NO_X for certain EGUs based on fuel type, unit size, cost effectiveness, and the presence or absence of pre-existing controls.

[40] ADEQ's CALPUFF visibility modeling indicates the highest modeled visibility impact of AEP Flint Creek No. 1 Boiler on nearby Class I areas is: 3.970 Δdv at Caney Creek; 3.781 Δdv at Upper Buffalo; 3.983 Δdv at Hercules Glade; 2.596 Δdv at Mingo; 1.420 Δdv at Sipsey. ADEQ's post-control visibility modeling shows that the State's BART determinations would result in the source still causing visibility impairment at Caney Creek (1.573 Δdv), Upper Buffalo (2.089 Δdv), and Hercules Glade (1.541 Δdv), and contributing to visibility impairment at Mingo (0.927) (Appendix 9.2B of the Arkansas Regional Haze SIP).

[41] See, *e.g.,* William J. Gretta and others, The SCR Retrofit Design for the Seminole Generating Station, PowerGen, 2008, Hitachi SCR at Seminole Electric Delivers 0.04 lb/MMBtu NO_X (Preliminary Results), FGD and $DeNO_X$ Newsletter, December 2009, No. 380, and NO_X CEMS data reported to Clean Air Markets.

[42] Clay Erickson, Robert Lisauskas, and Anthony Licata, What New in SCRs, DOE's Environmental Control Conference, May 16, 2006, p. 28. Available here: *http://www.netl.doe.gov/publications/proceedings/06/ecc/pdfs/Licata.pdf;* LG&E Energy, Selective Catalytic Reduction: From Planning to Operation, Competitive Power College, December 2005, p. 75–77.

[43] See also Sargent & Lundy, IPM Model—Revisions to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, Final, August 2010, p. 1 ("It should be noted that the lowest available SO_2 emission guarantees, from the original equipment manufacturers of SDA FGD systems, are 0.06 lb/MMBtu.").

[44] Georgia Environmental Protection Division, Longleaf Energy Station, Permit No. 4911–099–0033–P–01–0, April 9, 2010. Available at: *http://airpermit.dnr.state.ga.us/gaairpermits/PermitPDF.aspx?id=PDF-PI-18499.*

[45] U.S. EPA, Region 9, Prevention of Significant Deterioration Permit, Desert Rock Energy Company, July 31, 2008. Available at: *http://www.regulations.gov/search/Regs/home.html#docketDetail?R=EPA-R09-OAR-2007-1110.*

firing scenario for Unit 4, Entergy made no BART determination for SO_2, and determined that BART for PM is the existing PM emission limit in the operating air permit. ADEQ agreed with the Entergy's determination. Revisions to the State's RH Rule, Chapter 15 of APC&E Commission Regulation 19, which were submitted to us on August 3, 2010, state the existing PM emission limit as of October 15, 2007 is PM BART for the natural gas firing scenario for Entergy Lake Catherine Unit 4. This corresponds to an emission limit of 45 lb/hr PM.[46] We agree that SO_2 and PM emissions from natural gas-fired boilers are generally very low, and therefore we are proposing to approve ADEQ's decision not to make a BART determination for SO_2 for the natural gas firing scenario for Unit 4. Since we have found that the visibility impact of Unit 4 due to PM emissions alone (from natural gas firing) is so minimal such that the installation of any additional PM controls on the unit would likely achieve very low emissions reductions, have minimal visibility benefits, and not be cost-effective, we are also proposing to approve ADEQ's determination that BART for PM for Unit 4 for the natural gas firing scenario is the existing PM emission limit as of October 15, 2007, or 45.0 lb/hr.

Regarding BART for NO_X for the natural gas firing and fuel oil firing scenarios, Entergy conducted a BART analysis to determine what retrofit controls are BART for Lake Catherine Unit 4. In Step 1 of the BART analysis for NO_X, Entergy considered a combination of the following NO_X combustion controls for the natural gas firing scenario: boiler tuning, burners out of service (BOOS), induced flue gas recirculation (IFGR), overfire air (OFA), and low NO_X burners (LNB). Entergy considered a combination of the following NO_X combustion controls for the fuel oil firing scenario: boiler tuning, boiler modifications, BOOS, and forced flue gas recirculation (FFGR). However, Entergy did not consider post-combustion controls for NO_X, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR), even though these controls are technically feasible and available technologies for reducing NO_X emissions currently used by similar facilities. We provided comments to ADEQ to this effect on May 1, 2007.[47] In response to our comments, Arkansas included in its RH SIP submittal the results of a computerized model it obtained from Entergy, which according to the source, evaluated Unit 4's performance and the capital and operation and maintenance costs associated with each identified control technology. Entergy reported that the results of the computerized model showed that post-combustion controls, such as SCR and SNCR, had a cost that would be uneconomical to install. The results of this computer model are discussed further in our discussion of Step 4 of the BART analysis.

For Step 3 of the NO_X BART analysis, Entergy evaluated the control effectiveness of the control options considered in Step 1 for both the natural gas and fuel oil firing scenarios. We generally agree with Entergy's evaluation of the control effectiveness of all control options considered. In Step 4 of the BART analysis, Entergy considered the costs of compliance for each control option. In evaluating the costs of compliance, Entergy analyzed the cost-effectiveness in annualized dollars per ton of NO_X removed ($/ton) of the control options identified in Step 1 of the BART analysis for NO_X for the natural gas and fuel oil firing scenarios. We note there are two flaws in Entergy's cost-analysis. Entergy provided no documentation or detailed breakdown of the cost estimates. The results of the computer model the source used to determine the cost-effectiveness of post-combustion controls also did not provide documentation or a detailed breakdown of the cost estimates. We have no basis to verify the validity of neither the cost estimates nor Entergy's determination based on the cost estimation analysis for BART. The basis for cost estimates should be documented either with data supplied by a vendor (*i.e.,* budget estimates or bids) or by a referenced source. This was not done in the BART analysis. Furthermore, Unit 4 is a peaking unit,[48] and Entergy attempted to account for this by assuming a 10% capacity factor[49] in the calculation of the metrics for tons removed and $/ton removed for all control options considered in Step 1 of the BART analysis. The computer model Entergy used to estimate the cost effectiveness of post-combustion controls likewise assumed a 10% capacity factor in the calculation of the metrics for tons removed and $/ton removed. Given that there are no permit requirements in place that would limit the operation of this unit to 10% capacity, the facility can legally be operated well above the 10% capacity factor assumed by Entergy. Thus, any cost effectiveness analysis based on a 10% capacity factor is likely to significantly inflate the cost per ton of controlling this unit. In support of the 10% capacity utilization factor, Entergy stated that the unit has operated, on average, at a capacity of 6.9% for the past three years. However, past use of this unit was much higher—approximately 46% on average—over the 2001–2005 period.[50] Given the variability in capacity utilization of this unit over the past ten years, the assumed 10% capacity utilization should be supported by an enforceable limit. Therefore, we are proposing to disapprove ADEQ's NO_X BART determination for both the natural gas and fuel oil firing scenarios for Lake Catherine Unit 4.

For SO_2 BART for the fuel oil-firing scenario, Entergy identified only one available control option in Step 1 of the BART analysis- use of fuel oil with low sulfur content. ADEQ agreed with the source's decision. Entergy only considered the use of fuel oil with 1%, 0.5%, and 0.2% sulfur content by weight. We note use of fuel oil with 1% sulfur content is the base case, as Entergy stated the source's current Title V permit limits the sulfur content of fuel oil used to 1%. Entergy did not consider any post-combustion SO_2 controls in the BART analysis, even though post-combustion control technologies, such as wet and dry scrubbers, are currently being used by comparable facilities to control SO_2 emissions. As such, Entergy did not identify and consider control technologies that are capable of the maximum level of control that is achievable, as is required by the BART guidelines and the RHR. In Step 3 of the

[46] See ADEQ Operating Air Permit for Entergy Arkansas Inc.-Lake Catherine Plant (Permit No. 1717–AOP–R4). This permit can be viewed at *http://www.adeq.state.ar.us/ftproot/pub/WebDatabases/PermitsOnline/Air/1717-AOP-R4.pdf.*

[47] Our comments on this matter are documented in Appendix 9.3B of the Arkansas RH SIP.

[48] 40 CFR 72.2 defines a peaking unit as ''[a] unit that has (i) An average capacity factor of no more than 10.0 percent during the previous three calendar years and (ii) A capacity factor of no more than 20.0 percent in each of those calendar years.''

[49] 40 CFR 72.2 defines capacity factor as either ''(1) The ratio of a unit's actual annual electric output (expressed in MWe/hr) to the unit's nameplate capacity (or maximum observed hourly gross load (in MWe/hr) if greater than the nameplate capacity) times 8760 hours; or (2) The ratio of a unit's annual heat input (in million British thermal units or equivalent units of measure) to the unit's maximum rated hourly heat input rate (in million British thermal units per hour or equivalent units of measure) times 8,760 hours.

[50] Table 2–1 of the ''BART Analysis for Lake Catherine Plant- Unit 4,'' prepared by Robert Paine, December 2006 notes that Unit 4 was operated 6,988 hours in 2001 (79.7% utilization); 5,651 hours in 2002 (64.5% utilization); 3,972 hours in 2003 (45.3% utilization); 1,534 hours in 2004 (17.5% utilization); and 2,059 hours in 2005 (23.5% utilization).

BART analysis, Entergy considered the control effectiveness of all technically feasible control options identified in Step 1 by using AP–42 factors for 1%, 0.5%, and 0.2% sulfur residual oil to determine the amount of sulfur dioxide emissions that would be eliminated by use of low sulfur fuel oil. Entergy found that based on a 10% capacity factor, use of 0.5% sulfur fuel oil would result in 1,059 tpy SO_2 removed from the baseline and use of 0.2% sulfur fuel oil would result in 1,802 tpy SO_2 removed from the baseline. In Step 4 of the BART analysis, Entergy considered the costs of compliance for each control option. Entergy provided no documentation or detailed breakdown of the costs estimates for low sulfur fuel oil. Therefore, we have no basis to verify the validity of either the cost estimates or ADEQ's BART determination based on the cost estimation. The basis for cost estimates should be documented, and should clearly indicate the amount of fuel oil that corresponds to the annual cost listed in the cost-analysis. After conducting post-control visibility modeling, Entergy determined and ADEQ agreed that SO_2 BART for the fuel oil firing scenario is an SO_2 emission limit of 0.562 lb/MMBtu on a 30 day rolling average. The RH SIP provides conflicting information on whether this emission limit corresponds to use of 1% or 0.5% sulfur fuel oil. On September 27, 2011, ADEQ submitted a supplemental submittal clarifying that the 0.562 lb/MMBtu emission limit corresponds to use of 0.5% sulfur content fuel oil. However, for the reasons discussed above, we are proposing to find that the source and ADEQ did not properly follow the requirements of section 51.308(e)(1)(ii)(A) in determining SO_2 BART for the fuel oil firing scenario. Specifically, we are proposing that ADEQ did not properly take into consideration ''the technology available'' and ''the costs of compliance.''

Regarding BART for PM for the fuel oil firing scenario, Entergy identified the PM_{10} emission rates associated with use of 1%, 0.5%, and 0.2% sulfur fuel oil. Entergy determined PM BART for Unit 4 for the fuel oil firing scenario is 0.037 lb/MMBtu on a 30 day rolling average. ADEQ's September 27, 2011 supplemental submittal clarified that this PM emission limit corresponds to use of 0.5% sulfur content fuel oil. ADEQ and Entergy did not consider any post-combustion controls in the BART analysis for PM for the fuel oil firing scenario. We note the use of a wet scrubber system that controls both SO_2 and PM emissions may prove to be cost-effective and provide for substantial visibility improvement and should therefore be considered in Unit 4's BART analysis.

We are proposing to find that Entergy and ADEQ did not properly follow the requirements of section 51.308(e)(1)(ii)(A) in determining BART for NO_X for both the natural gas and fuel oil firing scenarios and BART for SO_2 and PM for the fuel oil firing scenario for the Entergy Lake Catherine Unit 4. Specifically, we are proposing that ADEQ did not properly take into consideration ''the technology available'' and ''the costs of compliance.'' For the reasons identified above, we are proposing to disapprove ADEQ's BART determinations for PM, NO_X, and SO_2 under oil firing conditions, and NO_X under natural gas firing conditions. We are proposing to approve ADEQ's BART determination for the Entergy Lake Catherine Unit 4 for PM under gas firing conditions and ADEQ's decision to make no BART determination for SO_2 under gas firing conditions.

d. Entergy White Bluff Units 1, 2, and Auxiliary Boiler BART Determinations

The White Bluff Units 1 and 2 and the Auxiliary Boiler are BART-eligible sources. Units 1 and 2 are coal fired boilers with a maximum power rating of 850 MW each and a heat input rate of 8700 MMBtu/hr each. Units 1 and 2 are permitted to burn both sub-bituminous and bituminous coal as the primary fuel and No. 2 fuel oil or bio-diesel as the start-up fuel. The Auxiliary Boiler is a 183 MMBtu/hr boiler that is permitted to burn only No. 2 fuel oil or biodiesel. The Class I areas located within 300 km of the facility are Caney Creek, Upper Buffalo, and Hercules Glades. Since Units 1 and 2 are permitted to burn both bituminous and sub-bituminous coal, ADEQ made separate BART determinations for bituminous sub-bituminous coal firing.

Regarding BART for PM for Units 1 and 2, neither Entergy nor ADEQ performed a BART analysis to determine what retrofit controls are BART for Units 1 and 2. The source's rationale for this, which ADEQ agreed with, was its belief that most of the visibility-causing emissions from Units 1 and 2 are due to SO_2 and NO_X, and PM_{10} emissions are well-controlled with existing electrostatic precipitators (ESPs). We reviewed the CALPUFF visibility modeling submitted by ADEQ for Entergy White Bluff, and agree that PM emissions from the source have minimal visibility impacts at each Class I area within 300 km. Revisions to the Arkansas RH Rule (APC&E Commission Regulation 19, chapter 15) that were submitted to us by ADEQ on August 3, 2010, state the PM BART emission limit for White Bluff Units 1 and 2 is the existing PM emission limit in the air permit as of October 15, 2007. The federally enforceable operating air permit states the PM emissions from the two units are controlled with ESPs and requires that the two units comply with a PM emission standard of 0.10 lb/MMBtu.[51] Since we have found that the visibility impact of the source due to PM emissions alone is so minimal such that the installation of any additional PM controls on the units would likely achieve very low emissions reductions, have minimal visibility benefits, and not be cost-effective, we are proposing to approve ADEQ's determination that PM BART for both the bituminous and sub-bituminous coal firing scenarios is the existing PM emission limit for Units 1 and 2.

Regarding SO_2 BART for White Bluff Units 1 and 2, Entergy performed a BART analysis and determined that the presumptive limits of 0.15 lb/MMBtu for both the sub-bituminous and bituminous coal firing scenarios for SO_2 for Units 1 and 2 apply to the two units because they are greater than 200 MW each. Although Entergy performed a BART analysis for BART for SO_2, it considered only those control options that meet the presumptive limit of 0.15 lb/MMBtu, without considering whether a more stringent SO_2 emission limit is BART for Units 1 and 2. As stated elsewhere in this proposed rulemaking, the BART guidelines and the RHR require consideration of the most stringent control technology in the BART analysis. Because the control technology options considered in the BART analysis are capable of achieving a lower emission limit than the presumptive limit for this facility, and these controls are being currently used by similar facilities to control SO_2 emissions to an emission limit lower than the presumptive limit, consideration of these technologies and the lowest emission limit achievable must be included in the BART analysis.

In Step 1 of the SO_2 BART analysis for Units 1 and 2, Entergy identified two available options to control the units to the presumptive SO_2 limit: limestone forced oxidation (wet scrubbing) and lime spray dryer (dry scrubbing). Entergy did not identify either control option as technically infeasible. In Step

[51] ADEQ Operating Air Permit for Entergy Services Inc.—White Bluff Plant (Permit No. 0263–AOP–R6). This permit can be viewed at *http://www.adeq.state.ar.us/ftproot/pub/WebDatabases/PermitsOnline/Air/0263-AOP-R6.pdf.*

3 of the BART analysis, Entergy evaluated the control effectiveness of the two control options, stating the wet scrubber can achieve up to 95% control efficiency while the dry scrubber can achieve up to 92% control efficiency. In Step 4 of the BART analysis, Entergy evaluated the costs of compliance for the two control options. Entergy determined the installation of a wet scrubber would have an annualized cost of $17,023,735 with a cost effectiveness of $620/ton SO_2 removed at Unit 1 and an annualized cost of $17,159,021 with a cost-effectiveness of $620/ton SO_2 removed at Unit 2. Entergy also determined the installation of a dry scrubber would have an annualized cost of $34,035,909 with a cost effectiveness of $1280/ton SO_2 removed at Unit 1 and an annualized cost of $34,306,388 with a cost-effectiveness of $1280/ton SO_2 removed at Unit 2. In Step 5 of the BART analysis, Entergy evaluated the visibility impacts of the two control options. However, Entergy's modeling underestimated the visibility benefit anticipated from the use of wet or dry scrubbers because it modeled both control options at the same SO_2 emission rate of 0.15 lb/MMBtu, rather than at the achievable control effectiveness of 92% removal for dry scrubbing and 95% for wet scrubbing. We also note that Entergy deviated from the modeling protocol and used the 98th percentile (8th highest modeled day) in this analysis instead of the maximum modeled visibility impact. Entergy's post-control modeling showed that the visibility benefits for dry scrubbers and wet scrubbers is nearly the same (with dry scrubbing being slightly better due to a hotter plume and lower sulfuric acid emissions), while the annualized cost of a dry scrubber is nearly twice that of a wet scrubber. Entergy determined and ADEQ agreed that BART for SO_2 for Units 1 and 2 is installation and operation of a wet scrubber at each unit to achieve the presumptive BART limit of 0.15 lb/MMBtu for both the sub-bituminous and the bituminous coal firing scenarios. Entergy considered a wet scrubber achieving 0.15 lb/MMBtu to be the most stringent technology available. But as discussed elsewhere, wet scrubbers and dry scrubbers have been documented to achieve much lower emissions, including emissions as low as .065 lbs/MMBtu for dry scrubbers. Therefore, the evaluation is not acceptable. In addition, we note that the 0.15 lb/MMBtu presumptive BART limit established by ADEQ corresponds to 82% control removal of the wet scrubber at Unit 1 and 80% control removal at Unit 2, as indicated by ADEQ in the Arkansas RH SIP narrative.[52] Table A–1 in Appendix A of the BART analysis indicates the cost-effectiveness of installing and operating a wet scrubber is $620/ton SO_2 removed. Although Table A–1 indicates such cost-effectiveness value corresponds to operation of the wet scrubber at 95% control efficiency, neither ADEQ nor Entergy provided a breakdown of the cost estimates and we were therefore unable to verify whether it in fact corresponds to 95% control efficiency or if it corresponds to 80% control efficiency at Unit 2 and 82% control efficiency at Unit 1. Even if the $620/ton SO_2 removed cost-effectiveness value corresponds to only 82% control efficiency for Unit 1 and 80% control efficiency for Unit 2, we believe that the incremental cost of operating the wet scrubber at 95% vs. 80% and 82% control efficiency is relatively minimal, and is likely cost-effective. Since Entergy and ADEQ considered only the 0.15 lb/MMBtu SO_2 presumptive limit in the BART analysis for Units 1 and 2, even though a lower limit is technically achievable and more than likely cost-effective, we are proposing to disapprove ADEQ's determination that BART for SO_2 for Units 1 and 2 is the presumptive limit of 0.15 lb/MMBtu on a 30-day rolling average for both the sub-bituminous and bituminous coal firing scenarios.

Regarding NO_X BART for White Bluff Units 1 and 2, Entergy performed a BART analysis in which available combustion control technologies to control NO_X to the presumptive limit of 0.15 lb/MMBtu for the sub-bituminous coal-firing scenario and 0.28 lb/MMBtu for the bituminous coal-firing scenario were considered. As in the SO_2 BART analysis for Units 1 and 2, Entergy did not consider establishing NO_X BART emission limits more stringent than the NO_X presumptive limits. In Step 1 of the NO_X BART analysis, Entergy considered the following control options: boiler tuning, OFA, and LNB. Entergy did not evaluate post-combustion controls such as SCR and SNCR or any other NO_X control options capable of emission limits more stringent than the presumptive limits, when these are technically feasible and available and are currently being used by comparable facilities to control NO_X emissions at rates more stringent than the presumptive limit. Since Entergy did not identify the maximum control technology available as a control option in Step 1 of the BART analysis, the subsequent analysis in the remaining steps was incomplete. However, for the sake of providing a fuller picture of our evaluation of Entergy's BART analysis for NO_X for White Bluff Units 1 and 2, we discuss the remaining steps of the BART analysis.

Entergy did not identify any of the NO_X controls it listed in Step 1 of the BART analysis as being technically infeasible. In Step 3 of the BART analysis, Entergy evaluated the control effectiveness of the control options. Entergy determined boiler tuning will result in 37% control removal; a combination of boiler tuning and OFA will result in 53.6% control removal; and a combination of boiler tuning, OFA, and LNB will result in 69% control efficiency at each unit. In Step 4 of the BART analysis, Entergy evaluated the costs of compliance for the control options considered and determined that a combination of boiler tuning, OFA, and LNB has a control effectiveness of $463/ton NO_X removed for Unit 1 and $437/ton NO_X removed for Unit 2. We note Entergy's cost analysis of the NO_X control options included no documentation or detailed breakdown of the costs. We have no basis to verify the validity of neither the cost estimates nor Entergy and ADEQ's determination based on the analysis of cost estimation for BART. The basis for cost estimates must be documented either with data supplied by an equipment vendor (*i.e.,* budget estimates or bids) or by a referenced source. This was not done. Without either ADEQ or Entergy providing a breakdown of costs of material, labor, operation and maintenance, *etc,* we cannot verify the accuracy of Entergy's cost effectiveness determination. Furthermore, the cost-effectiveness analysis is problematic because Entergy assumed, and ADEQ agreed with, an 85% utilization of the two units when the units are capable of 100% utilization and there is no federally enforceable limit of 85% utilization in place.[53] Since the two units are technically and legally capable of operating at 100% utilization, a cost estimate assuming 85% utilization may underestimate the amount of emission reductions achieved by the controls and therefore under-represent the potential cost-effectiveness of such controls. In Step 5 of the BART analysis, Entergy evaluated the visibility impacts of the control options and subsequently determined that a combination of boiler

[52] See Table 9.3a of the Arkansas RH SIP.

[53] Based on operating hours provided by Entergy for Units 1 and 2, Unit 1 was operated 92.5% of the time in 2003, and Unit 2 was operated 92.7% of the time in 2004. See Table 2–1, under Section 2.2 of the BART analysis for Entergy White Bluff Units 1 and 2 (found in Appendix 9.3A of the RH SIP).

tuning, OFA, and LNB is BART for NO_X for Units 1 and 2, achieving an emission limit of 0.15 lb/MMBtu for the sub-bituminous coal firing scenario and 0.28 lb/MMBtu for the bituminous coal firing scenario. ADEQ agreed with the Entergy's determination.

As already explained in our evaluation of BART for SO_2 for Units 1 and 2, we disagree with Entergy and ADEQ's approach of not considering an emission limit more stringent than the presumptive limit when comparable facilities have used control technologies to reduce emissions below the presumptive limit. Also, as explained elsewhere in this notice, the BART Rule does not suggest the presumptive limits should be viewed as establishing a safe harbor from more stringent regulation under the BART provisions. ADEQ's CALPUFF pre-control modeling indicates the three subject to BART units at White Bluff together cause visibility impairment at Caney Creek, Upper Buffalo, Hercules Glade, Mingo, and Sipsey.[54] A considerable portion of this visibility impairment is due to NO_X emissions. ADEQ's post-control modeling indicates the three subject to BART units at White Bluff combined would still cause visibility impairment at all five Class I areas modeled (Caney Creek, Upper Buffalo, Hercules Glade, Mingo and Sipsey), and that a considerable portion of the post-control modeled visibility impairment is due to NO_X emissions. In light of the post-control modeling results, ADEQ and/or Entergy should have considered additional post-combustion controls, such as SNCR and SCR, that are capable of achieving NO_X emission limits well below the NO_X presumptive limits, and have been widely used by similar facilities to achieve emissions at rates below the presumptive limit. Therefore, we are proposing to disapprove ADEQ's determination that BART for NO_X for White Bluff Units 1 and 2 is 0.15 lb/MMBtu for the sub-bituminous coal firing scenario and 0.28 lb/MMBtu for the bituminous coal firing scenario.

With regard to the Auxiliary Boiler, neither ADEQ nor Entergy conducted a BART analysis that considered the statutory factors states are required to consider in determining what level of control is BART for a source, whether this be an emission limit or a work practice standard. The Arkansas RH SIP narrative states ADEQ decided to establish work practice standards for this source pursuant to 40 CFR 51.308(e)(1)(iii), rather than establish BART emission limits for SO_2, NO_X, and PM. APC&E Commission Regulation 19, Chapter 15, established that BART for the Auxiliary Boiler is a restriction to operate no more than 4360 hours annually. Since ADEQ's pre and post-control visibility modeling shows the visibility impact on surrounding Class I areas of all three units at the facility combined, we are not able to assess the visibility impact on Class I areas of the Auxiliary Boiler alone. The operating permit indicates the Auxiliary Boiler combusts No. 2 fuel oil or biodiesel to provide steam for Unit 1 and 2 start-up activities. The restriction established by ADEQ as BART would allow the Auxiliary Boiler to operate 50% of the time on an annual basis. In practice, an auxiliary boiler that is only needed for start-up is typically operated much less than that. We are proposing to find that ADEQ did not properly follow the requirements of section 51.308(e)(1)(ii)(A) because neither ADEQ nor Entergy performed a BART analysis for the Auxiliary Boiler for their chosen work practice standard. We are proposing to disapprove ADEQ's determination that BART for the White Bluff Auxiliary Boiler is a restriction to operate no more than 4360 hours annually.

e. Domtar Power Boilers No. 1 and 2 BART Determinations

The Domtar Power Boilers No. 1 and 2 are BART-eligible sources. The Power Boilers generate steam and electricity for the other processes within the Domtar kraft pulp mill. The No. 1 Power Boiler has a heat input rating of 580 MMBtu/hr and is permitted to burn bark, wood waste, municipal yard waste, recycled sanitary products composed of cellulose and polypropylene, pelletized paper fuel (PPF), No. 6 fuel oil, used oil generated on site, reprocessed fuel oil, tire derived fuel (TDF), and natural gas. The No. 1 Power Boiler is equipped with a traveling grate, a combustion air system, and a wet ESP for removal of PM emissions. According to the operating air permit, the No. 1 Power Boiler's permitted emission rate for PM/PM_{10} is 0.07 lb/MMBtu. The operating air permit provides that the sulfur content of the fuel oil used at the No.1 Power Boiler shall not exceed 3.0% by weight and that the No. 1 Power Boiler shall not use more than 2,700,000 gallons of fuel oil for any consecutive 12-month period. The permit also limits the total amount of TDF used at the Power Boilers No. 1, 2, and 3 combined to 220 tons in any 24-hour period.

The No. 2 Power Boiler has a heat input rating of 820 MMBtu/hr and burns primarily pulverized bituminous coal, but is also permitted to burn non-condensable gases (NCGs), bark and wood chips used to absorb oil spills, wood waste, municipal yard waste, natural gas, used oil generated on site, recycled sanitary products based on cellulose and polypropylene, No. 6 fuel oil, reprocessed fuel oil, TDF, and petroleum coke. The No. 2 Power Boiler is equipped with a traveling grate, combustion air system including OFA, multiclones for removal of PM emissions, and two venturi scrubbers in parallel for removal of remaining PM emissions and SO_2. According to the operating air permit, the No. 2 Power Boiler's permitted emission rate for PM/PM_{10} is 0.1 lb/MMBtu.

Regarding BART for PM, Domtar stated the No. 1 and 2 Power Boilers were at the time subject to the Boiler Maximum Achievable Control Technology (MACT) PM emission standard of 0.07 lb/MMBtu. A wet ESP was installed at the No. 1 Power Boiler to meet the 0.07 lb/MMBtu Boiler MACT PM emission standard. Domtar also stated that the No. 2 Power Boiler's existing wet scrubber is capable of meeting the Boiler MACT PM emission standard. Domtar noted that in the BART Guidelines, EPA encourages the use of streamlined approaches for BART determinations and elected to forego a BART analysis and to presumptively rely on the 0.07 lb/MMBtu Boiler MACT PM emission standard in existence at the time to meet the BART PM requirements for both the No. 1 and No. 2 Power Boilers. We note the BART Guidelines (Appendix Y to Part 51) provide that for VOC and PM sources subject to MACT standards, States may streamline the BART analysis by including a discussion of the MACT controls and whether any major new technologies have been developed subsequent to the MACT standards. The guidelines provide that unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, sources may rely on the MACT standards for purposes of BART.

Concerning Power Boiler No. 1, Domtar provided a discussion of other PM control technologies available at the time, and determined that a wet ESP with a PM emission limit of 0.07 lb/MMBtu on a 30-day rolling average is BART for Power Boiler No. 1. ADEQ agreed with Domtar's determination. We agree that ADEQ's determination for BART for PM for Power Boiler No. 1 is consistent with the BART Guidelines and are proposing to approve it.

[54] The maximum modeled pre-control Δdv values at surrounding Class I areas due to the three subject-to-BART units at White Bluff are: Caney Creek= 8.816 Δdv; Upper Buffalo= 7.750 Δdv; Hercules Glade=6.314 Δdv; Mingo=5.617; and Sipsey=5.843. See Appendix 9.2C of the Arkansas RH SIP.

Concerning Power Boiler No. 2, Domtar stated that the unit was subject to the Boiler MACT [55] PM emission standard in existence at the time (0.07 lb/MMBtu), and indicated its intent to presumptively rely on such standard to meet BART PM requirements for Power Boiler No. 2. However, instead of adopting 0.07 lb/MMBtu as the BART PM emission limit for Power Boiler No. 2, ADEQ adopted 0.10 lb/MMBtu as the BART PM emission limit. Since ADEQ did not select the Boiler MACT PM emission standard current at the time the BART determination was made as the BART PM emission limit for Power Boiler No. 2, ADEQ cannot elect to take the streamlined approach provided in the BART Guidelines. If ADEQ chooses to take the streamlined approach provided in the BART Guidelines, ADEQ must select the Boiler MACT PM standard if it determines there are no new and cost-effective technologies or available upgrades developed subsequent to the MACT standard. Otherwise, ADEQ and/or Domtar must perform a complete BART analysis that considers the statutory factors under section 51.308(e)(ii)(A) to determine BART for PM for Power Boiler No. 2. Furthermore, ADEQ's pre-control visibility modeling indicates a considerable portion of the combined visibility impact of No. 1 and 2 Power Boilers at Caney Creek is due to PM emissions.[56] Therefore, we are proposing to disapprove ADEQ's determination that BART for PM_{10} for Power Boiler No. 2 is 0.10 lb/MMBtu on a 30-day rolling average, and we are proposing to approve ADEQ's determination that BART for PM_{10} for Power Boiler No. 1 is 0.07 lb/MMBtu on a 30-day rolling average.

Regarding BART for SO_2 for Power Boiler No. 1, Domtar noted pre-combustion controls such as fuel switching/blending and fuel cleaning are ineffective, as wood has low sulfur content. Domtar also noted post-combustion controls such as flue gas desulfurization (FGD) and (*i.e.,* wet and dry scrubbers) have not been installed on wood-fired boilers because of the relatively low SO_2 emissions from wood combustion. Domtar determined that due to the low sulfur content of wood, SO_2 emissions from wood combustion are inherently low and ''have a negligible impact on visibility impairment.'' Domtar determined SO_2 BART for Power Boiler No. 1 is no additional SO_2 controls beyond the existing fuel restrictions (fuel oil with a maximum 3.0% sulfur content and a usage limitation of 2,700,000 gallons of fuel oil per consecutive 12-month period) are necessary. ADEQ agreed with Domtar's determination and decided that an emission limit of 1.12 lb/MMBtu on a 30-day rolling average is BART for SO_2 for Power Boiler No. 1. We note that ADEQ's CALPUFF pre-control modeling demonstrates the No. 1 Power Boiler emits more than one-third of the total modeled emissions of SO_2 from the two sources.

We agree that due to the low sulfur content of wood, SO_2 emissions from wood-fired boilers are generally relatively low. Table 1.6–2 of EPA's *Compilation of Air Pollutant Emission Factors* indicates the combustion of wood waste has a typical SO_2 emission rate of 0.025 lb/MMBtu.[57] In light of this, we question the appropriateness of an SO_2 emission limit of 1.12 lb/MMBtu for Power Boiler No. 1. Neither ADEQ nor Domtar provided any support for this emission limit. Domtar stated that approximately 75 percent of the heat input for Power Boiler No. 1 is supplied by bark. A unit combusting primarily bark should be capable of achieving an SO_2 emission rate much lower than 1.12 lb/MMBtu. The facility's current permit for this unit limits its annual SO_2 emissions to 214 tons per year (tons/year), which is a low figure. Therefore, there appears to be a mismatch between ADEQ's relatively high BART SO_2 emission limit and what the facility actually needs, based on its current permit. As part of its BART analysis, ADEQ and/or Domtar should have conducted a fuel inventory of this boiler in order to explore this issue. Other sources of potential sulfur emissions should have been investigated, including emissions resulting from burning fuel oil and TDF. ADEQ should also have considered lowering the sulfur content of fuel oil burned at the source, and/or lowering the limit on fuel oil usage. If Power Boiler No. 1 truly needs such a high SO_2 emission limit, then ADEQ and/or the Domtar should have investigated the feasibility, effectiveness, and cost of SO_2 controls. Therefore, we are proposing to find that ADEQ did not properly follow the requirements of section 51.308(e)(1)(ii)(A) in determining BART. We are proposing to disapprove ADEQ's determination that BART for SO_2 for Power Boiler No. 1 is 1.12 lb/MMBtu on a 30-day rolling average.

Regarding BART for SO_2 for Power Boiler No. 2, neither ADEQ nor Domtar performed a BART analysis that considered the statutory factors under section 51.308(e)(ii)(A). Domtar stated the unit is equipped with a wet scrubber for control of SO_2 and PM emissions. According to Domtar, the existing wet scrubber currently achieves an SO_2 control efficiency of approximately 90%. Domtar indicated that the BART Guidelines provide an option to skip the comprehensive BART analysis for subject to BART units already equipped with the most stringent controls available, including all possible improvements to control devices, as long as these are made federally enforceable for the purpose of implementing BART for the source. Domtar stated that since wet scrubbing is the most effective method of controlling SO_2 emissions and it has not identified any feasible upgrades to the existing wet scrubber, no BART analysis is necessary. ADEQ agreed with Domtar, and determined that no additional SO_2 removal is needed for the No. 2 Power Boiler, and BART for SO_2 is 1.20 lb/MMBtu on a 30-day rolling average using the existing wet scrubber.

We agree that the BART Guidelines allow sources to forego the BART analysis when the source already has the most stringent controls available in place and all possible improvements to control devices have been made. However, we disagree that a 1.20 lb/MMBtu SO_2 emissions rate corresponds to the most stringent control available. We note FGD systems are capable of SO_2 reduction efficiencies up to 98%.[58] Therefore, the 90% reduction efficiency claimed by Domtar does not correspond to the highest SO_2 control efficiency wet scrubbers are capable of achieving. The highest SO_2 control efficiency issue aside, although Domtar stated it did not identify any feasible upgrades to the existing wet scrubber, it provided no documentation of what upgrades were considered and why they were found to be technical infeasible. In considering all possible improvements to the scrubber, Domtar should have evaluated options that not only improve the design removal efficiency of the scrubber vessel itself, but also considered upgrades that can improve the overall SO_2 removal efficiency of the scrubber system. For example, the

[55] The MACT standards are part of the National Emission Standards for Hazardous Air Pollutants for Source Categories (NESHAP), provided under 40 CFR 63.

[56] ADEQ's pre-control modeling files are found in Appendix 9.2B of the Arkansas RH SIP. Since ADEQ's visibility modeling shows the visibility impact of No. 1 and 2 Power Boilers combined, we were unable to assess the visibility impact of No. 2 Power Boiler individually on surrounding Class I areas.

[57] Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources, AP–42, 5th Edition, January 1995.

[58] See EPA's *Air Pollution Control Fact Sheet* on FGD control technology, available at *http://www.epa.gov/ttn/catc/dir1/ffdg.pdf.*

BART Guidelines state that improving maintenance practices, adjusting scrubber chemistry, and increasing auxiliary equipment redundancy are some ways to improve average SO_2 removal efficiencies. For the reasons discussed above, we are proposing to find that ADEQ did not properly follow the requirements of section 51.308(e)(1)(ii)(A) in determining BART for SO_2 for Power Boiler No. 2. We are proposing to disapprove ADEQ's determination that BART for SO_2 for the No. 2 Power Boiler is 1.20 lb/MMBtu on a 30-day rolling average using the existing wet scrubber.

Regarding BART for NO_X for Power Boilers No. 1 and 2, Domtar performed a BART analysis to determine what controls are BART for the two boilers. In Step 1 of the NO_X BART analysis, Domtar identified the following control technologies: boiler tuning/optimization, fuel blending, FGR, LNB, OFA, SCR, SNCR, and reburning/methane de-NO_X. Domtar stated the source has employed and intends to continue to employ the latest boiler optimization and tuning techniques, and that such control technologies are considered part of the base case for Power Boilers No. 1 and 2. Similarly, Domtar explained it historically mixes 10–15% (heat input basis) wood with coal in the No. 2 Power Boiler and therefore fuel blending is considered part of the base case for the No. 2 Power Boiler. In Step 3 of the BART analysis, Domtar evaluated the technical feasibility of each control option. Domtar explained that since wood is inherently low in nitrogen content, fuel blending is not technically feasible for wood-fired boilers, and therefore eliminated this as a control option for Power Boiler No. 1. Regarding FGR, Domtar asserted that only thermal NO_X can be controlled by FGR. As most NO_X emissions from the No. 1 and No. 2 Power Boilers are due to fuel NO_X rather than thermal NO_X, Domtar determined FGR is technically infeasible for both power boilers. Domtar stated that combustion modification with LNB is used in both gas/oil-fired and coal fired units, but is not used for wood-fired boilers. Therefore, Domtar determined use of LNB is technically infeasible for Power Boiler No. 1. Regarding use of OFA, Domtar stated the source was informed by one OFA vendor that while OFA results in decreased NO_X emissions, the primary purpose is combustion optimization, and implementation of OFA can actually increase NO_X emissions in certain circumstances. Based on this, Domtar determined an OFA system upgrade at Power Boilers No. 1 and 2 is technically infeasible and eliminated this as a control option for both units in question. Domtar determined that methane de-NO_X is the only technically feasible NO_X control option for Power Boiler No. 1 and methane de-NO_X and LNB are the only two technically feasible NO_X control options for Power Boiler No. 2. In so doing, Domtar determined that SCR and SNCR are technically infeasible control options for No. 1 and 2 Power Boilers because they are not suited for power boilers that experience wide temperature variances and high load swings. We note a review of the RACT/BACT/LAER Clearinghouse (Process types 11.120 and 11.190) indicates there are several wood-fired utility boilers that employ SNCR. In particular, a similar source, the bark boiler at Temple Inland Kraft Linerboard Mill in Orange, Texas, employs SNCR, Low Excess Air (LEA), and low NO_X gas burners.[59] The Temple Inland Kraft boiler has a NO_X emission limit of 0.166 lb/MMBtu on a 30 day rolling average. Like the Domtar Power Boilers No. 1 and 2, the Temple Inland Kraft boiler exhibits load swing. We also note there are other similarities in the operating parameters of the bark boiler at Temple Inland Kraft and Power Boiler No. 1 (the bark boiler) at Domtar. Like Power Boiler No. 1 at Domtar, the bark boiler at Temple Inland Kraft is permitted to burn, among other fuel sources, bark/wood biomass, natural gas, and tire-derived fuel. The Temple Inland Kraft bark boiler has a maximum heat input rating of 656 MMBtu/hr, while Domtar Power Boiler No. 1 has a maximum heat input rating of 580 MMBtu/hr. In conducting its BART analysis, ADEQ and/or Domtar should have more carefully considered the use of post-combustion control technologies, such as SNCR, for both power boilers at Domtar, since SNCR is a control technology that has been used at similar facilities to control NO_X emissions. Because ADEQ eliminated some of the control options as being technically infeasible in Step 2 of the BART analysis, the subsequent analysis in remaining steps was incomplete. However, for the sake of providing a fuller picture of our evaluation of Domtar's BART analysis for NO_X for Domtar Power Boilers No. 1 and 2, we discuss the remaining steps of the BART analysis.

In Step 3 of the BART analysis, Domtar evaluated the control effectiveness of the control options it considered technically feasible. Domtar determined that methane de-NO_X has a potential control efficiency of 50%, whereas LNB has a potential control efficiency of 30%. In Step 4 of the BART analysis, Domtar evaluated the cost of compliance for each control option. Domtar determined the cost-effectiveness of methane de-NO_X is $7,262/ton NO_X removed at Power Boiler No. 1 and $4,259/ton NO_X removed at Power Boiler No. 2, while the cost-effectiveness of LNB is $1,465/ton NO_X removed at Power Boiler No. 1. Domtar eliminated consideration of methane de-NO_X at Power Boilers No. 1 and 2 due to its high cost. Since Domtar eliminated the only control option considered for Power Boiler No. 1 prematurely (before evaluating visibility impacts), it determined, and ADEQ agreed, that there are no NO_X controls available for Power Boiler No. 1 and ADEQ established a BART NO_X emission limit of 0.46 lb/MMBtu on a 30-day rolling average for Power Boiler No. 1. This would result in no additional NO_X emission reductions at Power Boiler No. 1 beyond baseline conditions.

Also based on the cost-effectiveness analysis, Domtar determined that BART for Power Boiler No. 2 is LNB and ADEQ established a BART NO_X emission limit of 0.45 lb/MMBtu on a 30-day rolling average for Power Boiler No. 2. After making BART determinations for the No. 1 and 2 Power Boilers, ADEQ modeled the visibility impacts of the controls it selected as BART. We note Domtar and ADEQ's approach for making NO_X BART determinations for the No. 1 and 2 Power Boilers is flawed, as the RHR and the BART Guidelines provide that the visibility impacts of all technically feasible control options, which corresponds to Step 5 of the BART analysis, must be considered before a BART determination is made. ADEQ and Domtar eliminated methane de-NO_X in the BART analysis for Power Boilers No. 1 and 2 due to high cost before evaluating the visibility impacts of this control option. Thereby, ADEQ modeled only the visibility impacts of LNB for Power Boiler No. 2.

ADEQ stated its post-control visibility modeling demonstrates the BART determinations for PM, SO_2, and NO_X for Power Boilers No. 1 and 2 will result in a combined visibility improvement of 9.9% at Caney Creek and 12.9% at Upper Buffalo.[60] We note this is very

[59] See the docket for this rulemaking to view the Title V permit for the Temple Inland Kraft Linerboard Mill.

[60] ADEQ's post-control modeling, showing the visibility improvement resulting from BART controls, demonstrates that the visibility impact of

Continued

minimal visibility improvement and that there is ample room for the additional visibility improvement that would result from BART controls more stringent than those selected by ADEQ and Domtar.

We are proposing to find that ADEQ did not properly follow the requirements of section 51.308(e)(1)(ii)(A) in determining NO_X BART for Power Boilers No.1 and 2. Specifically, we are proposing that ADEQ did not properly take into consideration ''the technology available'' and ''the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.'' We disagree with Domtar and ADEQ's assessment that use of SNCR at the two power boilers is technically infeasible. In addition, ADEQ did not model the visibility impacts of all technically feasible control options before making NO_X BART determinations. For these reasons, we are proposing to disapprove ADEQ's determination that BART for NO_X for Power Boiler No. 1 is a NO_X emission limit of 0.46 lb/MMBtu (which would achieve no NO_X emission reductions beyond the baseline) and that BART for NO_X for Power Boiler No. 2 is a NO_X emission limit of 0.45 lb/MMBtu (achieved by use of LNB).

f. ADEQ BART Results and Summary

We have reviewed ADEQ's BART determinations for the sources listed in Table 3, above. For the reasons discussed above, and as discussed in more detail in the TSD, we are proposing to find that ADEQ has partially satisfied the BART requirement of section 51.308(e). We are proposing to find that the BART determinations listed in Table 4 satisfy the BART requirement of section 51.308(e). We are proposing to find that the BART determinations listed in Table 5 do not satisfy the BART requirement of section 51.308(e). We are also proposing to find that the 6A and 9A Boilers at the Georgia-Pacific Crossett Mill are subject to BART and require a full BART analysis to satisfy the BART requirement of section 51.308(e).

TABLE 4—BART DETERMINATIONS SATISFYING SECTION 51.308(e)

Facility name	BART emission unit	Pollutant		BART emission limit[61]
American Electric Power Flint Creek Power Plant	Boiler No. 1	PM_{10}		existing PM emission limit (0.1 lb/MMBtu).
Entergy Lake Catherine Plant	Unit 4	natural gas firing.	SO_2	No BART Determination.
			PM_{10}	existing PM emission limit (45 lb/hr).
Entergy White Bluff Plant	Unit 1	bituminous coal firing.	PM_{10}	existing PM emission limit (0.1 lb/MMBtu).
		sub-bituminous coal firing.	PM_{10}	existing PM emission limit (0.1 lb/MMBtu).
	Unit 2	bituminous coal firing.	PM_{10}	existing PM emission limit (0.1 lb/MMBtu).
		sub-bituminous coal firing.	PM_{10}	existing PM emission limit (0.1 lb/MMBtu).
Domtar Ashdown Mill	No. 1 Power Boiler	PM_{10}		0.07 lb/MMBtu.

TABLE 5—BART DETERMINATIONS NOT SATISFYING SECTION 51.308(e)

Facility name	BART emission unit	Pollutant	BART emission limit[62]
Arkansas Electric Cooperative Corporation Carl E. Bailey Generating Station.	Unit 1	SO_2	Use of fuel oil with 1% sulfur content.
		NO_X	No BART Determination.
		PM	No BART Determination.
Arkansas Electric Cooperative Corporation John L. McClellan Generating Station.	Unit 1	SO_2	Use of fuel oil with 1% sulfur content.
		NO_X	No BART Determination.
		PM	No BART Determination.
American Electric Power Flint Creek Power Plant	Boiler No. 1	SO_2	0.15 lb/MMBtu.

Power Boilers No. 1 and 2 combined will be 2.038 Δdv at Caney Creek and 1.029 Δdv at Upper Buffalo after ADEQ's BART controls are put in place.

[61] Emission limits are based on a 30-day rolling average.

TABLE 5—BART DETERMINATIONS NOT SATISFYING SECTION 51.308(e)—Continued

Facility name	BART emission unit	Pollutant		BART emission limit [62]
		NO_X		0.23 lb/MMBtu.
Entergy Lake Catherine Plant	Unit 4	natural gas firing.	NO_X	0.15 lb/MMBtu.
		fuel oil firing	SO_2	0.562 lb/MMBtu.
			NO_X	0.25 lb/MMBtu.
			PM	0.037 lb/MMBtu.
Entergy White Bluff Plant	Unit 1	bituminous coal firing.	SO_2	0.15 lb/MMBtu.
			NO_X	0.28 lb/MMBtu.
		sub-bituminous coal firing.	SO_2	0.15 lb/MMBtu.
			NO_X	0.15 lb/MMBtu.
	Unit 2	bituminous coal firing.	SO_2	0.15 lb/MMBtu.
			NO_X	0.28 lb/MMBtu.
		sub-bituminous coal firing.	SO_2	0.15 lb/MMBtu.
			NO_X	0.15 lb/MMBtu.
	Auxiliary Boiler	All		Boiler to be operated no more than 4360 hrs annually.
Domtar Ashdown Mill	No. 1 Power Boiler	SO_2		1.12 lb/MMBtu.
		NO_X		0.46 lb/MMBtu.
	No. 2 Power Boiler	SO_2		1.2 lb/MMBtu.
		NO_X		0.45 lb/MMBtu.
		PM_{10}		0.1 lb/MMBtu.

4. Arkansas' Regional Haze Rule

APC&E Commission Regulation 19, Chapter 15 requires each source subject to BART to install and operate BART no later than 6 years after the effective date of ADEQ's regulation or 5 years after we approve this RH SIP, which ever comes first.[63]

ADEQ originally submitted Arkansas' RH Rule, the APC&E Commission Regulation 19, Chapter 15, along with the Arkansas RH SIP, which we received on September 23, 2008. On August 3, 2010, we received a SIP revision submittal from ADEQ revising several chapters of APC&E Commission Regulation 19, including chapter 15. The revisions to Chapter 15 of APC&E Commission Regulation 19 that we received on August 3, 2010 are mostly non-substantive amendments that revise the original version of the rule we received on September 23, 2008. Therefore, in this proposed rulemaking we are proposing to take action on the version of Chapter 15 of APC&E Regulation 19 contained in the submittal we received on September 23, 2008, as revised by the submittal received on August 3, 2010. The only portion of the August 3, 2010 SIP submittal we are proposing to take action on in this rulemaking is that portion revising chapter 15 of APC&E Regulation 19. In this proposed rulemaking, we are not proposing to take action on the portions of the August 3, 2010 SIP submittal that revise other chapters of APC&E Commission Regulation 19, as those chapters are not related to regional haze. We will take action on the revisions to other chapters of APC&E Commission Regulation 19 at a later time.

We are proposing to partially approve and partially disapprove chapter 15 of APC&E Commission Regulation 19. We are proposing to approve those portions of chapter 15 of APC&E Commission Regulation 19 that incorporate the BART determinations we are proposing to approve and those portions that are consistent with our overall action on the Arkansas RH SIP. Specifically, we are proposing to approve the following sections of chapter 15 of APC&E Commission Regulation 19: Reg. 19.1501, which establishes the purpose

[62] Emission limits are based on a 30-day rolling average.

[63] See Arkansas Pollution Control and Ecology Commission Reg. 19.1504(B).

of the rule; Reg. 19.1502, which incorporates by reference the definitions contained in 40 CFR 51.301, as in effect on June 22, 2007; Reg. 19.1503, which identifies the State's BART-eligible sources; the portion of Reg. 19.1504(A) that identifies AECC Bailey Generating Station (Unit 1), AECC McClellan Generating Station (Unit 1), Domtar Ashdown Mill (Power Boilers No. 1 and 2), Lake Catherine (Unit 4), White Bluff (Units 1, 2, and the Auxiliary Boiler), and AEP Flint Creek (Boiler No. 1) as subject to BART sources; Reg. 19.1504(B), which requires each source subject to BART to install and operate BART as expeditiously as possible, but no later than 6 years after the effective date of the State's regulation or 5 years after EPA approval of the RH SIP (whichever comes first);[64] Reg. 19.1504(C), which requires each source subject to BART to maintain the control equipment required by chapter 15, and establish procedures to ensure such equipment is properly operated and maintained; Reg. 19.1505(A)(3), which establishes PM BART for AEP Flint Creek Power Plant, Boiler 1; Reg. 19.1505(D)(3), which establishes PM BART for Domtar Ashdown Mill, Power Boiler No. 1; Reg. 19.1505(F)(3), which establishes PM BART (bituminous coal) for Entergy White Bluff, Unit 1; Reg. 19.1505(G)(3), which establishes PM BART (sub-bituminous coal) for Entergy White Bluff, Unit 1; Reg. 19.1505(I)(3), which establishes PM BART (bituminous coal) for Entergy White Bluff, Unit 2; Reg. 19.1505(J)(3), which establishes PM BART (sub-bituminous coal) for Entergy White Bluff, Unit 2; Reg. 19.1505(M)(2), which establishes PM BART (natural gas) for Entergy Lake Catherine Unit 4; Reg.19.1506, which provides the compliance provisions for the subject to BART sources; and Reg. 19.1507, which provides that the Part 70 permit of each facility subject to BART shall be subject to re-opening.

We are proposing to disapprove the portion of Chapter 15 of APC&E Commission Regulation 19 that fails to identify the 6A and 9A Boilers at the Georgia-Pacific Mill as subject to BART sources, and the portions that incorporate the State's BART determinations we are proposing to disapprove. Specifically, we are proposing to disapprove the following sections of Chapter 15 of the Arkansas Pollution Control and Ecology Commission Regulation 19: the portion of Reg. 19.1504(A) that fails to identify the 6A and 9A Boilers at the Georgia-Pacific Crossett Mill as subject to BART sources; Reg. 19.1505(A)(1), which establishes SO_2 BART for AEP Flint Creek Power Plant, Boiler 1; Reg. 19.1505(A)(2), which establishes NO_X BART for AEP Flint Creek Power Plant, Boiler 1; Reg. 19.1505(B), which establishes SO_2 BART for AECC Bailey Generating Station, Unit 1; Reg. 19.1505(C), which establishes SO_2 BART for AECC McClellan Generating Station, Unit 1; Reg 19.1505(D)(1), which establishes SO_2 BART for Domtar Ashdown Mill, Power Boiler No. 1; Reg. 19.1505(D)(2), which establishes NO_X BART for Domtar Ashdown Mill, Power Boiler No. 1; Reg. 19.1505(E)(1), which establishes SO_2 BART for Domtar Ashdown Mill, Power Boiler No. 2; Reg. 19.1505(E)(2), which establishes NO_X BART for Domtar Ashdown Mill, Power Boiler No. 2; Reg. 19.1505(E)(3), which establishes PM BART for Domtar Ashdown Mill, Power Boiler No. 2; Reg. 19.1505(F)(1), which establishes SO_2 BART (bituminous coal) for Entergy White Bluff, Unit 1; Reg. 19.1505(F)(2), which establishes NO_X BART (bituminous coal) for Entergy White Bluff, Unit 1; Reg. 19.1505(G)(1), which establishes SO_2 BART (sub-bituminous coal) for Entergy White Bluff, Unit 1; Reg. 19.1505(G)(2), which establishes NO_X BART (sub-bituminous coal) for Entergy White Bluff, Unit 1; Reg. 19.1505(H), which provides that when burning a mix of bituminous and sub-bituminous coal at White Bluff Unit 1, the NO_X BART limits shall be prorated using the percentage of each coal being used; Reg. 19.1505(I)(1), which establishes SO_2 BART (bituminous coal) for Entergy White Bluff, Unit 2; Reg. 19.1505(I)(2), which establishes NO_X BART (bituminous coal) for Entergy White Bluff, Unit 2; Reg. 19.1505(J)(1), which establishes SO_2 BART (sub-bituminous coal) for Entergy White Bluff, Unit 2; Reg. 19.1505(J)(2), which establishes NO_X BART (sub-bituminous coal) for Entergy White Bluff, Unit 2; Reg. 19.1505(K), which provides that when burning a mix of bituminous and sub-bituminous coal at White Bluff Unit 2, the NO_X BART limits shall be prorated using the percentage of each coal being used; Reg. 19.1505(L), which establishes BART for Entergy White Bluff, Auxiliary Boiler; Reg. 19.1505(M)(1), which establishes NO_X BART (natural gas) for Entergy Lake Catherine Unit 4; Reg. 19.1505(N)(1), which establishes SO_2 BART (fuel oil) for Entergy Lake Catherine Unit 4; Reg. 19.1505(N)(2), which establishes NO_X BART (fuel oil) for Entergy Lake Catherine Unit 4; and Reg. 19.1505(N)(3), which establishes PM BART (fuel oil) for Entergy Lake Catherine Unit 4.

E. Long-Term Strategy

As described in section IV.E of this action, the LTS is a compilation of state-specific control measures relied on by the state for achieving its RPGs. Arkansas' LTS for the first implementation period addresses the emissions reductions from federal, state, and local controls that take effect in the state from the end of the baseline period starting in 2004 until 2018. The Arkansas LTS was developed by ADEQ, in coordination with the CENRAP RPO, through an evaluation of the following components: (1) Construction of a CENRAP 2002 baseline emission inventory; (2) construction of a CENRAP 2018 emission inventory, including reductions from CENRAP member state controls required or expected under federal and state regulations, (including BART); (3) modeling to determine visibility improvement and apportion individual state contributions; (4) state consultation; and (5) application of the LTS factors.

1. Emissions Inventories

Section 51.308(d)(3)(iii) requires that Arkansas document the technical basis, including modeling, monitoring and emissions information, on which it relied upon to determine its apportionment of emission reduction obligations necessary for achieving reasonable progress in each mandatory Class I Federal area it affects. Arkansas must identify the baseline emissions inventory on which its strategies are based. Section 51.308(d)(3)(iv) requires that Arkansas identify all anthropogenic sources of visibility impairment considered by the state in developing its long-term strategy. This includes major and minor stationary sources, mobile sources, and area sources. Arkansas met these requirements by relying on technical analyses developed by its RPO, CENRAP, and approved by all state participants, as described below.

The emissions inventory used in the RH technical analyses was developed by CENRAP with assistance from Arkansas. ADEQ provided a statewide emissions inventory for 2002- representing the mid-point of the 2000–2004 baseline period, and a projected emissions inventory for 2018, the end of the first 10-year planning period. The 2018 inventory is based on visibility modeling conducted by CENRAP. The 2018 emissions inventory was

[64] On March 26, 2010, the Arkansas Pollution Control & Ecology Commission, Arkansas' rulemaking body, granted all Arkansas subject-to-BART sources a variance from the compliance deadline imposed by the State's RH Rule, such that these sources are now required to comply with BART requirements no later than 5 years after EPA approval of the RH SIP.

developed by projecting 2002 emissions and applying reductions expected from federal and state regulations affecting the emissions of the visibility-impairing pollutants NO_X, PM, SO_2, and VOCs.

a. Arkansas' 2002 Emission Inventory

ADEQ and CENRAP developed an emission inventory for five inventory source classifications: Point, area, non-road and on-road mobile sources, and biogenic sources for the baseline year of 2002. Arkansas' 2002 emissions inventory provides estimates of annual emissions for haze producing pollutants by source category as summarized in Table 6, based on information in section 7.0 of Arkansas' RH SIP.

TABLE 6—ARKANSAS' 2002 EMISSIONS INVENTORY

[Tons/year]

	SO_2	NH_3	NO_X	VOCs	PM_{10}	$PM_{2.5}$
Point	92,205	1	72,419	44,329	12,406	7,837
Area	29,889	152,436	27,450	93,548	148,433	68,000
Non-road mobile	5,490	49	62,472	54,785	5,673	5,220
On-road mobile	3,902	2,480	141,894	48,599	3,784	3,021
Biogenic	0	0	18,960	1,385,666	0	0
Total	131,485	154,967	323,195	1,626,927	170,296	84,078

See the TSD for details on how the 2002 emissions inventory was constructed. We are proposing that Arkansas' 2002 emission inventory is acceptable.

b. Arkansas' 2018 Emission Inventory

In constructing Arkansas' 2018 emission inventory, ADEQ used a combination of our Economic Growth Analysis System (EGAS 6), our mobile emissions factor model (MOBILE 6), our off-road emissions factor model (NONROAD), and the Integrated Planning Model (IPM) for electric generating units. CENRAP developed emissions for five inventory source classifications: point, area, non-road and on-road mobile sources, and biogenic sources. CENRAP used the 2002 emission inventory, described above, to estimate emissions in 2018. All control strategies expected to take effect prior to 2018 are included in the projected emission inventory. Arkansas' 2018 emissions inventory provides estimates of annual emissions for haze producing pollutants by source category as summarized in Table 7, based on information in section 7.0 of the Arkansas RH SIP.

TABLE 7—ARKANSAS' 2018 EMISSIONS INVENTORY

	SO_2	NH_3	NO_X	VOCs	PM_{10}	$PM_{2.5}$
Point	106,461	2,575	71,107	55,603	19,799	13,775
Area	31,169	201,722	31,531	107,387	148,592	69,585
Non-road mobile	211	49	34,305	31,475	3,678	3,387
On-road mobile	442	3,412	33,640	19,924	949	949
Biogenic	0	0	18,960	1,385,666	0	0
Total	138,283	207,758	189,542	1,600,055	173,019	87,695

See the TSD for details on how the 2018 emissions inventory was constructed. CENRAP and ADEQ used this and other state's 2018 emission inventories to construct visibility projection modeling for 2018. We are proposing that Arkansas' 2018 emission inventory is acceptable.

2. Visibility Projection Modeling

CENRAP performed modeling for the RH LTS for its member states, including Arkansas. The modeling analysis is a complex technical evaluation that began with selection of the modeling system. CENRAP used (1) The Mesoscale Meteorological Model (MM5) meteorological model, (2) the Sparse Matrix Operator Kernel Emissions (SMOKE) modeling system to generate hourly gridded speciated emission inputs, (3) the Community Multiscale Air Quality (CMAQ) photochemical grid model and (4) the Comprehensive Air Quality model with extensions (CAMx), as a secondary corroborative model. CAMx was also utilized with its Particulate Source Apportionment Technology (PSAT) tool to provide source apportionment for both the baseline and future case visibility modeling.

The photochemical modeling of RH for the CENRAP states for 2002 and 2018 was conducted on the 36-km resolution national regional planning organization domain that covered the continental United States, portions of Canada and Mexico, and portions of the Atlantic and Pacific Oceans along the east and west coasts. The CENRAP states' modeling was developed consistent with our guidance.[65]

CENRAP examined the model performance of the regional modeling for the areas of interest before determining whether the CMAQ model results were suitable for use in the RH assessment of the LTS and for use in the modeling assessment. The 2002 modeling efforts were used to evaluate air quality/visibility modeling for a historical episode—in this case, for calendar year 2002—to demonstrate the suitability of the modeling systems for subsequent planning, sensitivity, and emissions control strategy modeling. Model performance evaluation is performed by comparing output from

[65] Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze, (EPA–454/B–07–002), April 2007, located at *http://www.epa.gov/scram001/guidance/guide/final-03-pm-rh-guidance.pdf* Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations, August 2005, updated November 2005 (''our Modeling Guidance''), located at *http://www.epa.gov/ttnchie1/eidocs/eiguid/index.html,* EPA–454/R–05–001

model simulations with ambient air quality data for the same time period to determine whether the model's performance is sufficiently accurate to justify using the model for simulating future conditions. Once CENRAP determined the model performance to be acceptable, it used the model to determine the 2018 RPGs using the current and future year air quality modeling predictions, and compared the RPGs to the URP. The results of CENRAP's visibility projection modeling are discussed in the section that follows.

3. Sources of Visibility Impairment

Visibility impairment in Class I areas is the result of local air pollution as well as transport of regional pollution across long distances. CENRAP used CAMx with its Particulate Source Apportionment Technology (PSAT) tool to provide source apportionment by geographic region and major source category. The pollutants causing the highest levels of light extinction are associated with the sources causing the most visibility impairment.

a. Sources of Visibility Impairment in Caney Creek

Tables 8 and 9 show the modeled contributions to total extinction at Caney Creek for each source category and species for 2002 and 2018, respectively.[66] Visibility impairment at Caney Creek in 2002 on the worst 20% days is largely due to SO_4 from point sources that contributes over half (75.1 Mm^{-1}) of the total extinction of 133.93 Mm^{-1}. The largest contributions of SO_4 come from Texas (11.55 Mm^{-1} from all source categories) and the eastern United States (17.98 Mm^{-1}). Overall, the largest source region contributions to visibility impairment in 2002 are from the eastern United States (19.16 Mm^{-1}), Texas (14.89 Mm^{-1}), and Arkansas (13.57 Mm^{-1}).

In 2018, Arkansas sources will contribute the most to visibility impairment at Caney Creek, as large reductions in impairment from point sources in East Texas and the eastern U.S. will occur while SO_4 emissions, particularly from point sources, are expected to increase in Arkansas. The 2018 projection shows the total extinction at Caney Creek for the worst 20% days is estimated to be 85.84 Mm^{-1}, a reduction of approximately 36% from 2002 levels. Anticipated reductions of SO_4 emissions from point sources in Texas, the eastern United States, Indiana, and Ohio will account for a decrease of 24.41 Mm^{-1} in total light extinction, which is approximately half of the total expected reduction between 2002 and 2018. Even with such large expected reductions in SO_4 emissions from point sources in 2018, extinction due to point sources will still be the highest contributor to visibility impairment on the worst 20% days, accounting for over half of the total extinction. Visibility impairment from all Arkansas sources will decrease by 2.32 Mm^{-1}, almost entirely due to expected reductions from mobile sources. Total reductions in NO_3 emissions from mobile sources will contribute a decrease in total extinction of approximately 9 Mm^{-1}. There is an under-prediction bias in the model that must be considered when examining source apportionment results for SO_4. Use of a 12 km resolution modeling grid in CAMX reduced the summertime SO_4 bias but required large computational expense. The use of higher resolution modeling should be reconsidered in future modeling efforts.

TABLE 8—PROJECTED LIGHT EXTINCTION FOR 20% WORST DAYS AT CANEY CREEK WILDERNESS AREA IN 2002

[Mm^{-1}]

	Total [1]	Point	Natural	On-road	Non-road	Area
SO4	87.05	75.10	0.09	1.19	1.70	5.66
NO3	13.78	4.06	0.64	4.70	2.45	1.37
POA	10.50	1.29	1.33	0.46	1.34	5.32
EC	4.80	0.19	0.33	0.86	1.79	1.40
SOIL	1.12	0.19	0.01	0.01	0.01	0.87
CM	3.73	0.21	0.04	0.03	0.02	3.19
Sum	*133.93*	*81.04*	*2.45*	*7.26*	*7.31*	*17.81*

[1] Totals include contributions from boundary conditions and secondary organic matter.

TABLE 9—PROJECTED LIGHT EXTINCTION FOR 20% WORST DAYS AT CANEY CREEK WILDERNESS AREA IN 2018

[Mm^{-1}]

	Total [1]	Point	Natural	On-road	Non-road	Area
SO4	48.95	39.83	0.07	0.12	0.44	5.31
NO3	7.57	2.84	0.53	0.97	1.33	1.37
POA	9.93	1.76	1.18	0.14	1.03	5.09
EC	3.17	0.24	0.30	0.16	0.94	1.31
SOIL	1.29	0.35	0.01	0.01	0.01	0.87
CM	3.58	0.24	0.04	0.03	0.01	3.02
Sum	*85.84*	*45.27*	*2.12*	*1.44*	*3.76*	*16.96*

[1] Totals include contributions from boundary conditions and secondary organic matter.

[66] The species contributing to visibility extinction at Caney Creek and Upper Buffalo, shown on Tables 8–11, are the following: sulfate (SO_4), nitrate (NO_3), primary organic aerosols (POA), elemental carbon (EC), soil dust, and coarse mass (CM). These species' precursors are SO_2, NO_X, and in some cases, NH_3 and VOCs.

b. Sources of Visibility Impairment in Upper Buffalo

Tables 10 and 11 show the contributions to total extinction at Upper Buffalo for each source category and species for 2002 and 2018, respectively. Visibility impairment at Upper Buffalo in 2002 on the worst 20% days is largely due to SO_4 from point sources that contributes over half (72.17 Mm^{-1}) of the total extinction of 131.79 Mm^{-1}. The largest contributions of visibility impairment due to SO_4 come from the eastern United States (18.56 Mm^{-1}), Indiana (9.79 Mm^{-1}), Illinois (8.06 Mm^{-1}), and Kentucky (6.93 Mm^{-1}). Overall, the largest source region contributions to visibility impairment in 2002 are from the eastern United States (20.00 Mm^{-1}), Arkansas (13.47 Mm^{-1}), Indiana (10.20 Mm^{-1}), Illinois (9.64 Mm^{-1}), and Missouri (9.60 Mm^{-1}).

In 2018, Arkansas sources will contribute the most to visibility impairment at Upper Buffalo, as large reductions in impairment from point sources in Indiana, Illinois, Ohio and the eastern U.S. will occur while SO_4 emissions, particularly from point sources, are expected to increase in Arkansas. The 2018 projection shows the total extinction at Upper Buffalo for the worst 20% days is estimated to be 86.16 Mm^{-1}, a reduction of approximately 35% from 2002 levels. Anticipated reductions of SO_4 emissions from point sources in the eastern United States, Indiana, Illinois, Kentucky and Ohio will account for a decrease of 28.43 Mm^{-1} in total light extinction, more than 60% of the total expected reduction in impairment between 2002 and 2018. Even with such large expected reductions in SO_4 emissions from point sources in 2018, extinction due to point sources will still be the highest contributor to visibility impairment on the worst 20% days, accounting for approximately half of the total extinction. Visibility impairment from all Arkansas sources will decrease by 1.45 Mm^{-1}, due to expected reductions from mobile sources. Total reductions in NO_3 emissions from mobile sources will contribute a decrease in total extinction of approximately 8.5 Mm^{-1}. There is an under-prediction bias in the model that must be considered when examining source apportionment results forSO_4. Use of a 12 km resolution modeling grid in CAMX reduced the summertime sulfate bias but required large computational expense. The use of higher resolution modeling should be reconsidered in future modeling efforts.

TABLE 10—PROJECTED LIGHT EXTINCTION FOR 20% WORST DAYS AT UPPER BUFFALO WILDERNESS AREA IN 2002

[Mm^{-1}]

	Total [1]	Point	Natural	On-road	Non-road	Area
SO_4	83.18	72.17	0.08	1.15	1.67	5.24
NO_3	13.30	3.93	0.61	4.14	2.71	1.23
POA	10.85	1.06	1.33	0.47	1.38	5.75
EC	4.72	0.16	0.31	0.80	1.93	1.30
SOIL	1.21	0.20	0.02	0.01	0.01	0.93
CM	6.85	0.29	0.05	0.05	0.02	6.02
Sum	*131.79*	*77.80*	*2.39*	*6.62*	*7.72*	*20.46*

[1] Totals include contributions from boundary conditions and secondary organic matter.

TABLE 11—PROJECTED LIGHT EXTINCTION FOR 20% WORST DAYS AT UPPER BUFFALO WILDERNESS AREA IN 2018

[Mm^{-1}]

	Total [1]	Point	Natural	On-road	Non-road	Area
SO_4	45.38	37.09	0.06	0.12	0.42	4.95
NO_3	9.22	3.48	0.63	1.10	1.81	1.48
POA	10.17	1.48	1.20	0.14	1.01	5.49
EC	3.07	0.21	0.28	0.15	0.99	1.21
SOIL	1.40	0.40	0.01	0.01	0.01	0.93
CM	6.53	0.36	0.05	0.04	0.02	5.65
Sum	*86.16*	*43.02*	*2.24*	*1.57*	*4.25*	*19.71*

[1] Totals include contributions from boundary conditions and secondary organic matter.

c. Arkansas' Contribution to Visibility Impairment in Class I Areas Outside the State

CAMx PSAT results were also utilized to evaluate the impact of Arkansas emission sources in 2002 and 2018 on visibility impairment at Class I areas outside of the state. Arkansas sources are modeled to have contributions to the Class I areas in Missouri (Hercules-Glades and Mingo). Outside of Arkansas and Missouri, the largest contribution from Arkansas sources is at the Wichita Mountains Class I area in Oklahoma, amounting to 2.0% of the visibility impairment at Wichita Mountains in 2002 and 2.3% in 2018. Arkansas is also projected to contribute a small amount of visibility degradation at Class I areas in other states listed in Table 12. We agree that additional emission reductions in Arkansas, beyond those controlled through BART requirements, are not necessary to protect visibility at Class I areas outside of the state at this time. Table 12 summarizes the projected contribution from Arkansas emissions on visibility degradation at 9 Class I areas for the 20 percent worst days in 2002 and 2018, as modeled by CENRAP.[67]

[67] See Appendix E of the TSD for CENRAP Emissions and Air Quality Modeling To Support Regional Haze State Implementation, found in Appendix 8.1 of the Arkansas RH SIP.

TABLE 12—PERCENT CONTRIBUTION FROM ARKANSAS EMISSIONS TO TOTAL VISIBILITY IMPAIRMENT AT CLASS I AREAS ON 20% WORST DAYS [68]

Class I area	State	2002 (percent)	2018 (percent)
Upper Buffalo	Arkansas	10.2	14.0
Caney Creek	Arkansas	10.1	13.1
Hercules Glades	Missouri	5.9	7.6
Mingo	Missouri	3.3	4.4
Wichita Mountains	Oklahoma	2.0	2.3
Mammoth Cave	Kentucky	1.0	1.8
Bondville	Illinois	1.2	1.5
Breton Island	Louisiana	1.1	1.3
Cadiz	Kentucky	0.9	1.2

4. Consultation and Emissions Reductions for Other States' Class I Areas

As in the development of Arkansas' RPGs for Caney Creek and Upper Buffalo, ADEQ used CENRAP as its main vehicle for facilitating collaboration with FLMs and other states in satisfying its LTS consultation requirement. This helped ADEQ and other state environmental agencies analyze emission apportionments at Class I areas and develop coordinated RH SIP strategies.

Section 51.308(d)(3)(i) requires that Arkansas consult with other states if its emissions are reasonably anticipated to contribute to visibility impairment at that state's Class I area(s), and that Arkansas consult with other states if those states' emissions are reasonably anticipated to contribute to visibility impairment at Caney Creek and Upper Buffalo. ADEQ's consultations with other states are described in section V.C.3 above. The CENRAP visibility modeling demonstrates Arkansas sources are responsible for a visibility extinction of approximately 7.1 inverse megameters [69] (Mm^{-1}) at Hercules Glades and for a visibility extinction of approximately 4.95 Mm^{-1} at Mingo on the worst 20% days for 2002.[70] ADEQ consulted with Missouri, as well as with several other states whose emissions have a potential visibility impact at Caney Creek and Upper Buffalo. As already discussed elsewhere in this proposed notice, ADEQ neither requested additional emission reductions from other states, nor made a commitment to other states for additional emission reductions beyond those already factored in to the CENRAP's photochemical modeling for the 2018 visibility projections. All states participating in ADEQ's consultation process agreed with this decision.

We are proposing to find that ADEQ's consultations satisfy the requirements under section 51.308(d)(3)(i) and (ii).

5. Mandatory Long Term Strategy Factors

Section 51.308(d)(3)(v) requires that Arkansas consider certain factors in developing its long-term strategy (the LTS factors). These include: (1) Emission reductions due to ongoing air pollution control programs, including measures to address 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. For the reasons outlined below, we are proposing to find that Arkansas has not satisfied all the requirements of Section 51.308(d)(3)(v).

a. Reductions Due to Ongoing Air Pollution Programs

In addition to its BART determinations, Arkansas' LTS incorporates emission reductions due to a number of ongoing air pollution control programs. This includes EPA's Clean Air Interstate Rule (CAIR), which was expected to cap Arkansas' ozone season trading budget for annual NOx allocations at 9,596 tons by 2015. Consistent with EPA guidance and regulations (see 70 FR 39104, 39106 (July 6, 2005)), many states relied on EPA's Clean Air Interstate Rule (CAIR) to satisfy key elements of Regional Haze SIPs. The D.C. Circuit, however, found CAIR to be inconsistent with the requirements of the Act and remanded the rule to the Agency. *North Carolina* v. *EPA,* 531 F.3d 896, 929–30 (D.C. Cir. 2008); modified on rehearing, *North Carolina* v. *EPA,* 550 F.3d 1176, 1178 (D.C. Cir. 2008). In response to the remand of the CAIR rule, on July 6, 2011, EPA finalized the Transport Rule, also known as the Cross-State Air Pollution Rule (CSAPR), a rule intended to reduce the interstate transport of fine particulate matter and ozone (see 76 FR 48208). Since Arkansas was subject to CAIR only for ozone season NOx, its Regional Haze SIP did not rely on CAIR to meet the requirements for BART or for attaining the in-state emissions reductions necessary to ensure reasonable progress. Instead, Arkansas evaluated controls for its potential BART sources. Arkansas made BART determinations for its subject to BART sources, including Electric Generating Units (EGUs) that might have been controlled under CAIR. Controls on these sources are an element of Arkansas' LTS for attaining the RPGs at Caney Creek and Upper Buffalo. In terms of the LTS, EPA anticipates that the Transport Rule will result in similar or better improvements in visibility than those predicted from CAIR at Class I areas in Arkansas. As a result, we do not expect the remand of CAIR to have a significant negative effect on the ability of Arkansas' LTS to ensure that Caney Creek and Upper Buffalo meet the RPGs in the State's RH SIP. We note that to assess whether a state's current strategies will be sufficient to meet its RPGs, the RHR requires a midcourse review by each state and, if necessary, a correction of the state's regional haze plan. *See* 40 CFR 52.308(g). If for a particular Class I area, the emissions reductions resulting from the Transport

[68] Contributions less than 1% were excluded from Table 12.

[69] An inverse megameter is the direct measurement unit for visibility impairment data. It is the amount of light scattered and absorbed as it travels over a distance of one million meters. Deciviews (dv) can be calculated from extinction data as follows: $dv = 10 \times \ln (b_{ext}(Mm^{-1})/10)$.

[70] See Appendix E of the TSD for CENRAP Emissions and Air Quality Modeling To Support Regional Haze State Implementation, found in Appendix 8.1 of the Arkansas RH SIP.

Rule do not provide similar or greater benefits than CAIR and if meeting the RPGs at one of its Class I areas is in jeopardy, the State will be required to address this circumstance in its five year review.

ADEQ also considered the Tier 2 Vehicle Emission Standards in developing its LTS. Federal Tier 2 Vehicle Emission Standards for passenger cars and light trucks were fully implemented in 2007 and similar rules for heavy trucks were scheduled to be implemented by 2009. These federal standards will result in reductions of emissions of PM, ozone precursors, and non-methane organic compounds. In developing its LTS, ADEQ also considered the Highway Diesel and Nonroad Diesel Rules, which mandated the use of lower sulfur fuels in diesel engines beginning in 2006 for highway diesel fuel, and 2007 for nonroad diesel fuel. These federal rules have resulted in more effective control of PM emissions from diesel engines by allowing the installation of control devices that were technically infeasible for fuels with higher sulfur content.

We approved Arkansas' Visibility Protection SIP on February 10, 1986 (51 FR 4910). We approved Arkansas' Part II Visibility Protection SIP, which addresses reasonably attributable visibility impairment (RAVI) at Caney Creek and Upper Buffalo, on July 21, 1988 (53 FR 27514). As we note in section IV.H of this proposed notice, the FLMs did not identify any integral vistas in Arkansas. In addition, Caney Creek and Upper Buffalo are not experiencing RAVI, nor are any Arkansas sources affected by the RAVI provisions. For this reason, the Arkansas RH SIP does not incorporate any measures to specifically address RAVI.

b. Measures To Mitigate the Impacts of Construction Activities

Section 51.308(d)(3)(v)(B) requires that Arkansas consider measures to mitigate the impacts of construction activities in developing its LTS. Construction-related activities are believed to be a small contributor to fine and coarse particulates. ADEQ notes that since the Arkansas Water and Air Pollution Control Act does not apply to land clearing, land grading, or road construction operations, ADEQ has limited opportunities to mitigate air emissions resulting from construction activities. However, ADEQ notes the federal General Conformity program requires assessment of the potential impacts of any construction-related emissions of criteria pollutants from federal projects in areas that have been designated as not attaining the National Ambient Air Quality Standards (NAAQS) for that pollutant. ADEQ also participates in the Blue Skyways Collaborative, a regional group that works collaboratively on the introduction of innovative, regional-scale, transportation-related programs and projects. The State has directed grant funds to fleet managers and equipment suppliers as a means of subsidizing diesel retrofits and the biodiesel market.

c. Emissions Limitations and Schedules of Compliance

Section 51.308(d)(3)(v)(C) requires that in developing its LTS, Arkansas consider emissions limitations and schedules of compliance to achieve the RPGs. The SIP contains emission limits and schedules of compliance for those sources subject to BART: the AECC Bailey Unit 1; the AECC McClellan Unit 1; the AEP Flint Creek Boiler No. 1; the Entergy Lake Catherine Unit 4; the Entergy White Bluff Units 1, 2, and the Auxiliary Boiler; and the Domtar Power Boilers No. 1 and 2. The schedules for implementation of BART for these sources are identified in Section 9.3 of the RH SIP and in the State's RH Rule included in Appendix 9.3C of the SIP. The BART emission limits established by ADEQ are an element of the LTS, and since we are proposing to disapprove a portion of ADEQ's BART determinations, we cannot propose to approve this element of the LTS.

d. Source Retirement and Replacement Schedules

Section 51.308(d)(3)(v)(D) requires that Arkansas consider source retirement and replacement schedules in developing its LTS. ADEQ stated retirement and replacement will be managed in conformance with existing SIP requirements pertaining to the Prevention of Significant Deterioration (PSD) and the New Source Review (NSR) programs. ADEQ notes source retirement and replacement will be tracked through on-going point source inventories.

e. Agricultural and Forestry Smoke Management Techniques

Section 51.308(d)(3)(v)(E) requires that Arkansas consider smoke management techniques for agricultural and forestry management purposes in developing its LTS. ADEQ considered smoke management techniques for the purposes of agricultural and forestry management in its LTS. Regulation 18 of the Arkansas Pollution Control and Ecology Commission contains a general prohibition on ''open burning of refuse, garbage, trade waste, or other waste material,'' but exempts controlled fires used for forest and wildlife management and certain agricultural activities (ADEQ Reg. 18.602–18.603). In 2007, the Arkansas Forestry Commission approved revisions to the Arkansas Smoke Management Program (SMP). The Arkansas SMP is designed to assure that prescribed fires are planned and executed in a manner designed to minimize impacts associated with the smoke produced by prescribed fires. The Arkansas SMP recommends a written fire plan that includes measures that can be taken to reduce residual smoke from burning activities. The Arkansas SMP also includes a process to evaluate potential smoke impacts at sensitive receptors and guidelines for scheduling fires such that exposure of sensitive populations is minimized and visibility impacts in Class I areas are avoided.

f. Enforceability of Emissions Limitations and Control Measures

Section 51.308(d)(3)(v)(F) requires that Arkansas ensure the enforceability of emission limitations and control measures used to meet reasonable progress goals. ADEQ has ensured that all emission limitations and control measures used to meet RPGs are enforceable by incorporating these into State regulations.[71] The State's RH Rule, Chapter 15 of the APC&E Commission Regulation 19, contains the BART requirements for all subject to BART sources in Arkansas. ADEQ has also committed to issuing enforceable Part 70 air quality permits requiring BART-eligible sources subject to BART to install BART and achieve the associated BART emission limits. Subject sources must achieve the BART emission limits referenced above within five years of our approval of the SIP, as required by section 51.308(e)(1)(iv). ADEQ determined that emission limitations or control measures other than BART are not currently required in order to meet the established RPGs. As discussed previously, we disagree with this position and are proposing to disapprove the RPGs.

g. Anticipated Net Effect on Visibility Due to Projected Changes

Section 51.308(d)(3)(v)(G) requires that in developing its LTS, Arkansas consider the anticipated net effect on visibility due to projected changes in point, area, and mobile source

[71] See ''Arkansas Pollution Control and Ecology Commission Regulation No. 19—Regulations of the Arkansas Plan of Implementation for Air Pollution Control,'' found in Appendix 9.3C of the Arkansas RH SIP.

emissions over the period addressed by the long-term strategy. In developing its RH SIP, ADEQ relied on the CENRAP's 2018 modeling projections, which show that net visibility is expected to improve by 3.88 dv at Caney Creek and 3.75 dv at Upper Buffalo. CENRAP's 2018 modeling projections account for changes in point, area, and on-road and non-road mobile emissions. The results of CENRAP's 2018 modeling projections are discussed in sections IV.E.2 and IV.E.3 of this proposed rulemaking.

6. Our Conclusion on Arkansas' Long Term Strategy

We are proposing to partially approve and partially disapprove Arkansas' LTS. Because we are proposing to disapprove some of ADEQ's BART determinations, we are also proposing to disapprove the corresponding emission limits and schedules of compliance that Arkansas relied on as part of its LTS. With the exception of this element, the LTS satisfies the requirements of 40 CFR 51.308(d)(3), and we are proposing to approve these remaining elements.

F. Coordination of RAVI and Regional Haze Requirements

Our visibility regulations direct states to coordinate their RAVI LTS and monitoring provisions with those for RH, as explained in section IV, above. Under our RAVI regulations, the RAVI portion of a state SIP must address any integral vistas identified by the FLMs pursuant to 40 CFR 51.304. *See* 40 CFR 51.302. An *integral vista* is defined in 40 CFR 51.301 as a ''view perceived from within the mandatory Class I Federal area of a specific landmark or panorama located outside the boundary of the mandatory Class I Federal area.'' Visibility in any mandatory Class I Federal area includes any integral vista associated with that area. The FLMs did not identify any integral vistas in Arkansas. In addition, Caney Creek and Upper Buffalo are not experiencing RAVI, nor are any Arkansas sources affected by the RAVI provisions. Thus, the Arkansas RH SIP submittal does not explicitly address the two requirements regarding coordination of RH with the RAVI LTS and monitoring provisions. However, Arkansas previously made a commitment to address RAVI should the FLM certify visibility impairment from an individual source.[72] We are proposing to find that this RH submittal appropriately supplements and augments Arkansas' RAVI visibility provisions to address RH by updating the monitoring and LTS provisions. We discuss the relevant monitoring provisions in the section that follows.

[72] Arkansas' part II Visibility Protection SIP contained RAVI provisions and was approved by EPA on July 21, 1988 (53 FR 27514).

G. Monitoring Strategy and Other SIP Requirements

Section 51.308(d)(4) requires the SIP contain a monitoring strategy for measuring, characterizing, and reporting of RH visibility impairment that is representative of all mandatory Class I Federal areas within the state. This monitoring strategy must be coordinated with the monitoring strategy required in Section 51.305 for reasonably attributable visibility impairment. As Section 51.308(d)(4) notes, compliance with this requirement may be met through participation in the IMPROVE network. Since the monitors at Caney Creek and Upper Buffalo are IMPROVE monitors, we are proposing that ADEQ has satisfied this requirement. See the TSD for details concerning the IMPROVE network.

Section 51.308(d)(4)(i) requires the establishment of any additional monitoring sites or equipment needed to assess whether reasonable progress goals to address RH for all mandatory Class I Federal areas within the state are being achieved. The IMPROVE monitor at Upper Buffalo was installed in 1991. Shortly after the creation of CENRAP, its monitoring workgroup noted there was a visibility void in Southern Arkansas. In 2001, the Caney Creek Wilderness area IMPROVE monitor was added to help fill that void. ADEQ also commits in the Arkansas RH SIP to evaluate the monitoring network periodically and consider evaluation technology changes and the need for new monitors. With the addition of the monitor at Caney Creek, we are proposing to find that ADEQ has satisfied this requirement.

Section 51.308(d)(4)(ii) requires that ADEQ establish procedures by which monitoring data and other information are used in determining the contribution of emissions from within Arkansas to RH visibility impairment at mandatory Class I Federal areas both within and outside the state. The monitor at Caney Creek is operated by Caney Creek Wilderness Area personnel, while the monitor at Upper Buffalo is operated by Upper Buffalo Wilderness Area personnel. The IMPROVE monitoring program is national in scope, and other states have similar monitoring and data reporting procedures, ensuring a consistent and robust monitoring data collection system. As section 51.308(d)(4) indicates, participation in the IMPROVE program constitutes compliance with this requirement. We are therefore proposing that ADEQ has satisfied this requirement.

Section 51.308(d)(4)(iv) requires that the SIP must provide for the reporting of all visibility monitoring data to the Administrator at least annually for each mandatory Class I Federal area in the state. To the extent possible, Arkansas should report visibility monitoring data electronically. Section 51.308(d)(4)(vi) also requires that ADEQ provide for other elements, including reporting, recordkeeping, and other measures, necessary to assess and report on visibility. We are proposing that Arkansas' participation in the IMPROVE network ensures the monitoring data is reported at least annually, is easily accessible, and therefore complies with this requirement.

Section 51.308(d)(4)(v) requires that ADEQ maintain a statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any mandatory Class I Federal area. The inventory must include emissions for a baseline year, emissions for the most recent year for which data are available, and estimates of future projected emissions. The State must also include a commitment to update the inventory periodically. Please refer to section V.G., above, where we discuss ADEQ's emission inventory. ADEQ has stated that it intends to update the Arkansas statewide emissions inventories periodically. We are proposing that this satisfies the requirement in section 51.308(d)(4)(v).

H. Federal Land Manager Coordination

Both Caney Creek and Upper Buffalo are federally protected wilderness areas for which the United States Department of Agriculture (USDA) Forest Service is the FLM. Although the FLMs are very active in participating in the RPOs, the RHR grants the FLMs a special role in the review of the RH SIPs, summarized in section III.H., above. We view both the FLMs and the state environmental agencies as our partners in the RH process.

Section 51.308(i)(1) requires that by November 29, 1999, Arkansas must have identified in writing to the FLMs the title of the official to which the FLM of Caney Creek and Upper Buffalo can submit any recommendations on the implementation of section 51.308. We acknowledge this section has been satisfied by all states via communication prior to this SIP.

Under Section 51.308(i)(2), Arkansas was obligated to provide the Forest Service with an opportunity for consultation, in person and at least 60 days prior to holding a public hearing on it RH SIP. In practice, state environmental agencies have usually provided all FLMs—the Forest Service, the Park Service, and the Fish and Wildlife Service, copies of their RH SIP, as the FLMs collectively have reviewed these RH SIPs. ADEQ followed this practice and sent its draft of this implementation plan revision to the federal land manager staff on February 22, 2008 and notified the federal land manager staff of the public hearing held on July 7, 2008.

Section 51.308(i)(3) requires that ADEQ provide in its RH SIP a description of how it addressed any comments provided by the FLMs. ADEQ has provided that information in Appendix 2.1 of its RH SIP.

Lastly, Section 51.308(i)(4) specifies the RH SIP must provide procedures for continuing consultation between the state and Federal Land Manager on the implementation of the visibility protection program required by section 51.308, including development and review of implementation plan revisions and 5-year progress reports, and on the implementation of other programs having the potential to contribute to impairment of visibility in the mandatory Class I Federal areas. ADEQ has stipulated in its RH SIP it will continue to coordinate and consult with the FLMs as required by section 51.308(i)(4). ADEQ states it intends to consult the FLMs in the development of future progress reports and plan revisions, as well as during the implementation of programs having the potential to contribute to visibility impairment at Caney Creek and Upper Buffalo. We are proposing that ADEQ has satisfied section 51.308(i).

I. Periodic SIP Revisions and Five-year Progress Reports

ADEQ affirmed its commitment to complete items required in the future under our RHR. ADEQ acknowledged its requirement under 40 CFR 51.308(f), to submit periodic progress reports and RH SIP revisions, with the first report due by July 31, 2018 and every ten years thereafter.

ADEQ also acknowledged its requirement under 40 CFR 51.308(g), to submit a progress report in the form of a SIP revision to the us every five years following this initial submittal of the Arkansas RH SIP. The report will evaluate the progress made towards the RPGs for each mandatory Class I area located within Arkansas and in each mandatory Class I area located outside Arkansas which may be affected by emissions from within Arkansas. We are proposing that ADEQ has satisfied section 51.308(f) and (g).

J. Determination of the Adequacy of Existing Implementation Plan

Section 51.308(h) requires that Arkansas take one of the listed actions, as appropriate, at the same time the State is required to submit any 5-year progress report to EPA in accordance with section 51.308(g). ADEQ has committed in its SIP to take one of the actions listed under 51.308(h), depending on the findings of the five-year progress report. We are proposing that ADEQ has satisfied section 51.308(h).

V. Our Analysis of Arkansas' Interstate Visibility Transport SIP Provisions

We received a SIP from Arkansas to address the interstate transport requirements of CAA 110(a)(2)(D)(i) for the 1997 8-hour ozone and $PM_{2.5}$ NAAQS on April 2, 2008. Concerning such CAA requirements preventing sources in the state from emitting pollutants in amounts which will interfere with efforts to protect visibility in other states, Arkansas stated that the State's RH Rule, the APC&E Commission Regulation 19, chapter 15, satisfies the requirement of section 110(a)(2)(D)(i) regarding the protection of visibility. Arkansas indicated in the April 2, 2008 submittal that at the time, it was not possible to assess whether there is any interference with measures in the applicable SIP for another State designed to protect visibility for the 8-hour ozone and $PM_{2.5}$ NAAQS in other states, until such time as Arkansas submits and EPA approves the Arkansas RH SIP.

As an initial matter, we note that section 110(a)(2)(D)(i)(II) does not explicitly specify how we should ascertain whether a state's SIP contains adequate provisions to prevent emissions from sources in that state from interfering with measures required in another state to protect visibility. Thus, the statute is ambiguous on its face, and we must interpret that provision.

Our 2006 Guidance recommended that a state could meet the visibility prong of the transport requirements of section 110(a)(2)(D)(i)(II) of the CAA by submission of the RH SIP, due in December 2007. Our reasoning was that the development of the RH SIPs was intended to occur in a collaborative environment among the states. In fact, in developing their respective reasonable progress goals, CENRAP states consulted with each other through CENRAP's work groups. As a result of this process, the common understanding was that each state would take action to achieve the emissions reductions relied upon by other states in their reasonable progress demonstrations under the RHR. CENRAP states consulted in the development of reasonable progress goals, using the products of this technical consultation process to co-develop their reasonable progress goals. In developing their visibility projections using photochemical grid modeling, CENRAP states assumed a certain level of emissions from sources within Arkansas, consistent with the BART determinations made by ADEQ. In the State's September 27, 2011 supplemental submittal, ADEQ clarified that the base year modeling inventory used by CENRAP in the 2002 base case modeling was prepared by the CENRAP Modeling Workgroup and its consultants, and was derived primarily from the 2002 National Emissions Inventory (NEI). ADEQ also clarified that it provided the CENRAP Modeling Workgroup with the controlled BART source emission limits contained in the State's RH Rule, the APC&E Commission Regulation 19, Chapter 15, for inclusion in the CENRAP's 2018 future case modeling. ADEQ stated in its Interstate Transport SIP that it is relying on the State RH Rule to meet the visibility prong of the transport requirements of section 110(a)(2)(D)(i)(II) of the CAA. The State's RH Rule became effective October 15, 2007. The current language of the regulation requires Arkansas' subject to BART sources to comply with BART requirements no later than five years after EPA approval of the RH SIP or 6 years after the effective date of the regulation, whichever is first. However, on March 26, 2010, the Arkansas Pollution Control & Ecology Commission, Arkansas' rulemaking body, granted all Arkansas subject to BART sources a variance from the compliance deadline imposed by the State's RH Rule, such that these sources are now required to comply with BART requirements no later than 5 years after EPA approval of the RH SIP.[73] Compliance with these BART requirements will ensure that Arkansas obtains its share of the emission reductions relied upon by other states to meet the RPGs for their Class I areas. Since compliance of Arkansas' subject to BART sources with BART requirements is dependent upon our approval of the RH SIP, and since we are proposing to disapprove a portion of the RH SIP, including some of Arkansas'

[73] A copy of the Arkansas Pollution Control and Ecology Commission's Minute Order can be viewed at *http://www.adeq.state.ar.us/ftproot/Pub/commission/minute_orders/10-08_Petition_from_Variance_Entergy_Swepco_AECC.pdf.*

BART determinations, a portion of the emission reductions committed to by Arkansas and relied upon by other states will not be realized.

As we are proposing to disapprove a majority of the BART determinations made by ADEQ for its subject to BART sources, we are proposing to find that the Arkansas SIP revision submittal does not fully ensure that emissions from sources in Arkansas do not interfere with other State's visibility programs as required by section 110(a)(2)(D)(i)(II) of the CAA. Specifically, the BART determinations we are proposing to disapprove, will not result in the corresponding emission reductions other states relied on to achieve the RPGs in their Class I areas. Therefore, we are proposing to partially approve and partially disapprove the portion of the Arkansas Interstate Transport SIP submittal that addresses the visibility requirement of section 110(a)(2)(D)(i)(II) that emissions from Arkansas sources not interfere with measures required in the SIP of any other state under part C of the CAA to protect visibility.

VI. Proposed Action

A. Regional Haze

We are proposing to partially approve and partially disapprove Arkansas' RH SIP revision submitted on September 23, 2008, August 3, 2010, and supplemented on September 27, 2011. Specifically, we are proposing to approve the following:

- The State's identification of affected Class I areas;
- The establishment of baseline and natural visibility conditions;
- The Uniform Rate of Progress (URP);
- The State's reasonable progress goal (RPG) consultation and the long-term strategy (LTS) consultation;
- The regional haze monitoring strategy and other SIP requirements under section 51.308(d)(4);
- The State's commitment to submit periodic regional haze SIP revisions and periodic progress reports describing progress towards the RPGs;
- The State's commitment to make a determination of the adequacy of the existing SIP at the time a progress report is submitted;
- And the State's consultation and coordination with Federal land managers (FLMs)

We are proposing to disapprove the State's RPGs because Arkansas did not consider the four statutory factors that states are required to consider in establishing RPGs under the CAA and section 51.308(d)(1)(A).

We are proposing to partially approve and partially disapprove the portions of these submittals addressing the State's identification of subject to BART sources; the requirements for best available retrofit technology (BART); the State's RH Rule; and the LTS. Specifically, we are proposing to approve the following:

- The State's identification of BART-eligible sources, with the exception of the 6A Boiler at the Georgia-Pacific Crossett Mill, which we are proposing to find is BART-eligible;
- The State's identification of subject to BART sources, with the exception of its determination that the 6A and 9A Boilers at the Georgia-Pacific Crossett Mill are not subject to BART;
- The following BART determinations made by ADEQ: the PM BART determination for the No. 1 Boiler of the AEP Flint Creek plant; the SO_2 and PM BART determinations for the natural gas firing scenario for Unit 4 of the Entergy Lake Catherine plant; the PM BART determinations for both the bituminous and sub-bituminous coal firing scenarios for Units 1 and 2 of the Entergy White Bluff plant; and the PM BART determination for the No. 1 Power Boiler of the Domtar Ashdown Mill;
- The portion of the submittal we received on September 23, 2008, and as revised by the submittal received on August 3, 2010, that contains those portions of Chapter 15 of APC&E Commission Regulation 19 which correspond to the portions of the Arkansas RH SIP we are proposing to approve. Specifically, we are proposing to approve the following sections of Chapter 15 of APC&E Commission Regulation 19: Reg. 19.1501; Reg. 19.1502; Reg. 19.1503; the portion of Reg. 19.1504(A) that identifies AECC Bailey Generating Station (Unit 1), AECC McClellan Generating Station (Unit 1), Domtar Ashdown Mill (Power Boilers No. 1 and 2), Lake Catherine (Unit 4), White Bluff (Units 1, 2, and the Auxiliary Boiler), and AEP Flint Creek (Boiler No. 1) as subject to BART sources; Reg. 19.1504(B); Reg. 19.1504(C); Reg. 19.1505(A)(3); Reg. 19.1505(D)(3); Reg. 19.1505(F)(3); Reg. 19.1505(G)(3); Reg. 19.1505(I)(3); Reg. 19.1505(J)(3); Reg. 19.1505(M)(2); Reg. 19.1506; and Reg. 19.1507; and
- The State's LTS, with the exception of the portion of the LTS that relied on the BART emission limits and schedules of compliance we are proposing to disapprove.

We are proposing to disapprove the following:

- ADEQ's determination that the 6A and 9A Boilers of the Georgia-Pacific Crossett Mill are not subject to BART;
- The following BART determinations made by ADEQ: the NO_X, PM, and SO_2 BART determinations for both Unit 1 of the Arkansas Electric Cooperative Corporation (AECC) Bailey plant and Unit 1 of the AECC McClellan plant; the SO_2 and NO_X BART determinations for the No. 1 Boiler of the American Electric Power (AEP) Flint Creek plant; the NOx BART determination for the natural gas firing scenario and the PM, SO_2, and NO_X BART determinations for the fuel oil firing scenario for Unit 4 of the Entergy Lake Catherine plant; the SO_2 and NO_X BART determinations for both the bituminous and sub-bituminous coal firing scenarios for Units 1 and 2 of the Entergy White Bluff plant; the BART determination for the Auxiliary Boiler of the Entergy White Bluff Plant; the SO_2 and NO_X BART determinations for the No. 1 Power Boiler of the Domtar Ashdown Mill; and the SO_2, NO_X, and PM BART determinations for the No. 2 Power Boiler of the Domtar Ashdown Mill;
- A portion of Arkansas' Regional Haze Rule, APC&E Commission Regulation 19, chapter 15, which we received on September 23, 2008, and as revised by the submittal received on August 3, 2010. Specifically, we are proposing to disapprove the following sections of Chapter 15 of APC&E Commission Regulation 19: The portion of Reg. 19.1504(A) that fails to identify the 6A and 9A Boilers at the Georgia-Pacific Crossett Mill as subject to BART sources; Reg. 19.1505(A)(1); Reg. 19.1505(A)(2); Reg. 19.1505(B); Reg. 19.1505(C); Reg. 19.1505(D)(1); Reg. 19.1505(D)(2); Reg. 19.1505(E)(1); Reg. 19.1505(E)(2); Reg. 19.1505(E)(3); Reg. 19.1505(F)(1); Reg. 19.1505(F)(2); Reg. 19.1505(G)(1); Reg. 19.1505(G)(2); Reg. 19.1505(H); Reg. 19.1505(I)(1); Reg. 19.1505(I)(2); Reg. 19.1505(J)(1); Reg. 19.1505(J)(2); Reg. 19.1505(K); Reg. 19.1505(L); Reg. 19.1505(M)(1); Reg. 19.1505(N)(1); Reg. 19.1505(N)(2); and Reg. 19.1505(N)(3); and
- The portion of the State's LTS that relied on the BART emission limits and schedules of compliance we are proposing to disapprove.

B. Interstate Transport of Visibility

We are also proposing to partially approve and partially disapprove a portion of a SIP revision submitted by the State of Arkansas for the purpose of addressing the "good neighbor" provisions of the CAA section 110(a)(2)(D)(i) for the 1997 8-hour ozone NAAQS and the $PM_{2.5}$ NAAQS.

Specifically, we are proposing a partial approval and partial disapproval of the Arkansas Interstate Transport SIP provisions that address the requirement of section 110(a)(2)(D)(i)(II) that emissions from Arkansas sources not interfere with measures required in the SIP of any other state under part C of the CAA to protect visibility. Although the BART emission limits we are proposing to approve will result in the corresponding emission reductions other states relied on to achieve the RPGs in their Class I areas, the BART emission limits we are proposing to disapprove will not result in the corresponding emission reductions other states relied on to achieve the RPGs in their Class I areas. Therefore, ADEQ will obtain only a portion of its share of the emission reductions relied upon by other states to meet the RPGs for their Class I areas.

VII. Statutory and Executive Order Reviews

Under the Clean Air Act, 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, EPA's role is to approve state choices, provided that they meet the criteria of the Clean Air Act. 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 Order 12866 (58 FR 51735, October 4, 1993);
- 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 application of those requirements would be inconsistent with the Clean Air Act; 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, this rule does not have tribal implications as specified by Executive Order 13175 (65 FR 67249, November 9, 2000), because the SIP is not approved to apply in Indian country located in the state, and EPA notes that it will not impose substantial direct costs on tribal governments or preempt tribal law.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Intergovernmental relations, Nitrogen dioxide, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxides, Visibility, Interstate transport of pollution, Regional haze, Best available control technology.

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

Dated: October 3, 2011.

Al Armendariz,

Regional Administrator, Region 6.

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