ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R06–OAR–2010–0190; FRL–9279–7]

Approval and Promulgation of Implementation Plans; Oklahoma; Regional Haze State Implementation Plan; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Best Available Retrofit Technology Determinations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing to partially approve and partially disapprove a revision to the Oklahoma State Implementation Plan (SIP) submitted by the State of Oklahoma through the Oklahoma Department of Environmental Quality (ODEQ) on February 19, 2010 that addresses regional haze for the first implementation period. This revision was 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"). States are required to assure reasonable progress toward the national goal of achieving natural visibility conditions in Class I areas. EPA is proposing to approve a portion of this SIP revision as meeting certain requirements of the regional haze program and to partially approve and partially disapprove those portions addressing the requirements for best available retrofit technology (BART) and the long-term strategy (LTS). EPA is proposing a Federal Implementation Plan (FIP) to implement sulfur dioxide (SO_2) emission limits on six sources to address these issues. EPA also is proposing to disapprove the State's submitted alternative to BART; EPA is taking no action on the submitted reasonable progress goals at this time. In addition, EPA is proposing to partially approve and partially disapprove a portion of a revision to the Oklahoma SIP submitted by the State of Oklahoma on May 10, 2007 and supplemented on December 10, 2007. We are taking action on that portion of the submittals addressing the requirements of CAA as it applies to visibility for the 1997 8-hour ozone and 1997 particulate matter ($PM_{2.5}$) National Ambient Air Quality Standards (NAAQS). This portion of the submittals addresses the requirement that Oklahoma's SIP contain adequate provisions to prohibit emissions from interfering with measures required in another state to protect visibility. In this action, we propose a FIP to address the deficiencies in this portion of Oklahoma's SIP submittals. The proposed FIP will prevent emissions from six Oklahoma sources from interfering with other states' measures to protect visibility and to implement sulfur dioxide emission limits on these six sources to prevent such interference.

DATES: *Comments:* Comments must be received on or before May 23, 2011.

Public Hearing. An open house and public hearing for this proposal is scheduled to be held on Wednesday April 13, 2011, at the Metro Technology Centers, Springlake Campus, Business Conference Center, Meeting Rooms H and I, 1900 Springlake Drive, Oklahoma City, OK 73111, (405) 424–8324. The Metro Technology Centers Springlake Campus is located at the intersection of Martin Luther King Ave. and Springlake Dr. between NE. 36th and NE. 50th just south of the Oklahoma City Zoo and Kirkpatrick Center. Parking for the Business Conference Center is available at no charge. The open house will begin at 1 p.m. and end at 3 p.m. local time. The public hearing will be held from 4 p.m. until 6 p.m., and again from 7 p.m. until 9 p.m.

The public hearing will provide interested parties the opportunity to present information and opinions to EPA concerning our proposal. Interested parties may also submit written comments, as discussed in the proposal. Written statements and supporting information submitted during the comment period will be considered with the same weight as any oral comments and supporting information presented at the public hearing. We will not respond to comments during the public hearing. When we publish our final action, we will provide written responses to all oral and written comments received on our proposal. To provide opportunities for questions and discussion, we will hold an open house prior to the public hearing. During the open house, EPA staff will be available to informally answer questions on our proposed action. Any comments made to EPA staff during the open house must still be provided formally in writing or orally during the public hearing in order to be considered in the record.

At the public hearing, the hearing officer may limit the time available for each commenter to address the proposal to 5 minutes or less if the hearing officer determines it to be appropriate. We will not be providing equipment for commenters to show overhead slides or make computerized slide presentations. Any person may provide written or oral comments and data pertaining to our proposal at the Public Hearing. Verbatim transcripts, in English, of the hearing and written statements will be included in the rulemaking docket.

Addresses: Submit your comments, identified by Docket No. EPA–R06–OAR–2010–0190, by one of the following methods:

- *Federal e-Rulemaking Portal: http://www.regulations.gov.* Follow the online instructions for submitting comments.
- *E-mail: r6air_okhaze@epa.gov.*
- *Mail:* Mr. Joe Kordzi, Air Planning Section (6PD–L), Environmental Protection Agency, 1445 Ross Avenue, Suite 1200, Dallas, Texas 75202–2733.
- *Hand or Courier Delivery:* Mr. Joe Kordzi, Air Planning Section (6PD–L), Environmental Protection Agency, 1445 Ross Avenue, Suite 700, 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. Joe Kordzi, Air Planning Section (6PD–L), at fax number 214–665–7263.

Instructions: Direct your comments to Docket No. EPA–R06–OAR–2010–0190. 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 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 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 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 the 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 Oklahoma Department of Environmental Quality, 707 N Robinson, Oklahoma City, OK 73102.

FOR FURTHER INFORMATION CONTACT: Joe Kordzi, EPA Region 6 Air Planning Section, telephone 214–665–7186, e-mail address *r6air_okhaze@epa.gov.*

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

This action is being taken under section 110 and part C of the CAA.

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I. Overview of Proposed Actions

A. Regional Haze

We propose to partially approve and partially disapprove Oklahoma's regional haze (RH) SIP revision submitted on February 19, 2010. Specifically, we propose to disapprove the SO_2 BART determinations for Units 4 and 5 of the Oklahoma Gas and Electric (OG&E) Muskogee plant; Units 1 and 2 of the OG&E Sooner plant; and Units 3 and 4 of the American Electric Power/Public Service Company of Oklahoma (AEP/PSO) Northeastern plant. We propose to disapprove these SO_2 BART determinations because they do not comply with our regulations under 40 CFR 51.308(e).

We are also proposing to disapprove the long term strategy (LTS) under section 51.308(d)(3) because Oklahoma has not shown that the strategy is adequate to achieve the reasonable progress goals set by Oklahoma and by other nearby States. The visibility modeling used by Oklahoma in support of its SIP revision submittal assumed SO_2 reductions from the six sources [1] as identified above that Oklahoma did not secure when making its BART determinations for these sources. As we discuss elsewhere, ODEQ participated in the Central Regional Air Planning Association (CENRAP) visibility modeling development that assumed certain SO_2 reductions from these six BART sources. ODEQ also performed its consultations with other states with the understanding that these reductions would be secured. We propose a FIP to cure these defects in BART and the LTS.

[1] In this document, when we say "six BART sources," or "six sources," we mean Units 4 and 5 of the Oklahoma Gas and Electric Muskogee plant; Units 1 and 2 of the Oklahoma Gas and Electric Sooner plant; and Units 3 and 4 of the American Electric Power/Public Service Company of Oklahoma Northeastern plant.

We are also proposing to approve the remaining sections of the RH SIP submission, except as discussed below.

We propose to find that Units 4 and 5 of the OG&E Muskogee plant, Units 1 and 2 of the OG&E Sooner plant, and Units 3 and 4 of the AEP/PSO Northeastern plant are subject to BART under 40 CFR 51.308(e). Further, we propose a FIP that specifically imposes SO_2 BART emission limits on these sources. We propose that SO_2 BART for Units 4 and 5 of the OG&E Muskogee plant, Units 1 and 2 of the OG&E Sooner plant, and Units 3 and 4 of the AEP/PSO Northeastern plant is an SO_2 emission limit of 0.06 lbs/MMBtu that applies singly to each of these units on a 30 day rolling average. Additionally, we propose monitoring, recordkeeping, and reporting requirements to ensure compliance with these emission limitations.

We propose that compliance with the emission limits be within three (3) years of the effective date of our final rule. We solicit comments on alternative timeframes, of from two (2) years up to five (5) years from the effective date our final rule.

Should OG&E and/or AEP/PSO elect to reconfigure the above units to burn natural gas, as a means of satisfying their BART obligations under section 51.308(e), that conversion should be completed within the same time frame. We invite comments as to, considering the engineering and/or management challenges of such a fuel switch, whether the full 5 years allowed under section 308(e)(1)(iv) following our final approval would be appropriate.

We propose to disapprove section VI.E of the Oklahoma RH SIP entitled, "Greater Reasonable Progress Alternative Determination." We also propose to disapprove the separate executed agreements between ODEQ and OG&E, and ODEQ and AEP/PSO entitled "OG&E Regional Haze Agreement, Case No. 10–024, and "PSO Regional Haze Agreement, Case No. 10–025," housed within Appendix 6–5 of the RH SIP. We propose that these portions of the submittal are severable from the BART determinations and the LTS; therefore, no FIP is required.

We are taking no action on whether Oklahoma has satisfied the reasonable progress requirements of EPA's regional haze SIP requirements found at section 51.308(d)(1).

B. Interstate Transport of Visibility

We also propose to partially approve and partially disapprove a portion of a SIP revision we received from the State of Oklahoma on May 10, 2007, as supplemented on December 10, 2007, 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 which will * * * 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 measures to prohibit emissions that would interfere with the reasonable progress goals set to protect Class I areas in other states.

These SIP revisions were submitted to address the requirement that Oklahoma's SIP must have adequate provisions to prohibit emissions from adversely affecting another state's air quality through interstate transport. Oklahoma indicates in its May 10, 2007 submittal that it intended that its RH SIP be used to satisfy the requirements of section 110(a)(2)(D)(i)(II) that emissions from Oklahoma sources do not interfere with measures required in the SIP of any other state under part C of the CAA to protect visibility. Consistent with our proposed actions with regard to Oklahoma's RH SIP revision submittal, we also propose a partial approval and partial disapproval of the Oklahoma Interstate Transport SIP revision submittals that address the requirement of section 110(a)(2)(D)(i)(II).

Specifically, we propose a partial approval and partial disapproval of the Oklahoma Interstate Transport SIP revision submittals that address the requirement of section 110(a)(2)(D)(i)(II) that emissions from Oklahoma sources do not interfere with measures required in the SIP of any other state under part C of the CAA to protect visibility. We believe that the controls proposed under the proposed FIP, in combination with the controls required by the portion of the Oklahoma RH submittal that we propose to approve, will serve to prevent sources in Oklahoma from emitting pollutants in amounts which will interfere with efforts to protect visibility in other states.

II. SIP and FIP Background

The CAA requires each state to develop a plan that provides for the implementation, maintenance, and enforcement of the NAAQS. CAA section 110(a). We establish NAAQS under section 109 of the CAA. Currently, the NAAQS address six criteria pollutants: Carbon monoxide; nitrogen dioxide; ozone; lead; particulate matter; and sulfur dioxide. The plan developed by a state is referred to as the SIP. The content of the SIP is specified in section 110 of the CAA, other provisions of the CAA, and applicable regulations. A primary purpose of the SIP is to provide the air pollution regulations, control strategies, and other means or techniques developed by the state to ensure that the ambient air within that state meets the NAAQS. However, another important aspect of the SIP is to ensure that emissions from within the state do not have certain prohibited impacts upon the ambient air in other states through the interstate transport of pollutants. CAA section 110(a)(2)(D). States are required to update or revise SIPs under certain circumstances. *See* CAA section 110(a)(1). One such circumstance is our promulgation of a new or revised NAAQS. *Id.* Each state must submit these revisions to us for approval and incorporation into the federally enforceable SIP.

If a state fails to make a required SIP submittal or if we find that, the state's submittal is incomplete or unapprovable, then we must promulgate a FIP to fill this regulatory gap. CAA section 110(c)(1). As discussed elsewhere in this notice, we have made findings related to Oklahoma SIP revisions needed to address interstate transport and the requirement that emissions from Oklahoma sources do not interfere with measures required in the SIP of any other state to protect visibility, pursuant to section 110(a)(2)(D)(i)(II) of the CAA. We propose a FIP to address the deficiencies in the Oklahoma Interstate Transport SIP.

III. 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 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 manmade 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 were 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).

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.

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 Regional Planning Organizations 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, as applicable, including section 110(a)(2)(D)(i), which pertains to the interstate transport of certain emissions.

On April 25, 2005, we published a "Finding of Failure to Submit SIPs for Interstate Transport for the 8-hour Ozone and $PM_{2.5}$ NAAQS." 70 FR 21147. This included a finding that Oklahoma and other states had failed to submit SIPs for interstate transport of air pollution affecting visibility, and started a 2-year clock for the promulgation of a FIP by us, unless a state made a submission to meet the requirements of section 110(a)(2)(D)(i) and we approved the submission. *Id.*

On August 15, 2006, we issued our "Guidance for State Implementation Plan (SIP) Submission 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

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

[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).

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.

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 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 May 10, 2007, we received a SIP revision from Oklahoma to address the interstate transport provisions of CAA 110(a)(2)(D)(i) for the 1997 ozone and $PM_{2.5}$ NAAQS. We received a supplement to this SIP revision on December 10, 2007. In a prior action we approved the Oklahoma SIP submittal for the "interfere with measures to prevent significant deterioration" prong of section 110(a)(2)(D)(i) of the CAA. 75 FR 72695, November 26, 2010. On February 19, 2010, Oklahoma submitted a RH SIP to address interstate transport of emissions that could interfere with efforts to protect visibility in other states. Because, for the reasons outlined below, we can only partially approve this RH SIP, we propose to partially approve and partially disapprove the Oklahoma Interstate Transport SIP revision submittals that address the requirement that emissions from Oklahoma sources do 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 propose to promulgate a FIP in order to cure this defect in the Oklahoma Interstate Transport SIP revision submittals.

IV. 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 manmade air pollution by reducing anthropogenic emissions that cause RH. The national goal is a return to natural conditions, *i.e.,* manmade 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.

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;

[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").

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, 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.

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 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

[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 (DC 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.

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). 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.

V. Our Analysis of Oklahoma's Regional Haze SIP

On February 19, 2010, we received a RH SIP revision from the State of Oklahoma for approval into the Oklahoma SIP. The following is a discussion of our evaluation of that submission. The parts of the submittal 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 ODEQ's submission in the order in which the regulations appear in 40 CFR 51.308, and a more comprehensive technical analysis.

A. Affected Class I Areas

In accordance with 40 CFR 51.308(d), ODEQ has identified one Class I area within its borders, the Wichita Mountains National Wildlife Refuge (Wichita Mountains). ODEQ has also determined that Oklahoma emissions have a small potential to impact visibility at Class I areas outside of Oklahoma. Based on projections of visibility in 2018 for the 20% worst visibility days, ODEQ has projected that Oklahoma emissions are responsible for visibility degradation at the Hercules Glades in Missouri of approximately 3.61%, the Salt Creek in New Mexico of approximately 2.53%, and the Guadalupe Mountains in Texas of approximately 2.0%.[11] We note that these projections are based on modeling done by CENRAP that assumed a certain level of reductions of SO_2 emissions from six sources that Oklahoma did not actually require in its submitted RH SIP revision. We expect that Oklahoma's projected impacts on visibility at Class I areas outside of Oklahoma would be greater had these controls and the associated SO_2 emission reductions not been included in CENRAP's visibility modeling.

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,[12] ODEQ calculated baseline/current and natural visibility conditions for its Class I area, the Wichita Mountains, 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.[13] 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.

ODEQ opted to use the default estimates for the natural conditions combined with the "new Improve equation," for Wichita Mountains. This is an acceptable approach under our 2003 Natural Visibility Guidance. For the Wichita Mountains, the default natural visibility value for the 20 percent worst days is 11.07 deciviews and for the 20 percent best days it is 3.39 dv. For the Wichita Mountains, ODEQ also used the new IMPROVE equation to calculate the "refined" natural visibility value for the 20 percent worst days to be 7.53 deciviews and for the 20 percent best days to be 4.2 deciviews. We have reviewed ODEQ's estimate of the natural visibility conditions and propose to find it acceptable using the new IMPROVE equation.

The new IMPROVE equation takes into account the most recent review of the science[14] and it accounts for the effect of particle size distribution on light extinction efficiency of sulfate, nitrate, 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

[11] Unless otherwise noted, when we refer to visibility impacts, we mean the impacts due solely to the source or state named, which do not include natural conditions.

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

[13] 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.

[14] The science behind the revised IMPROVE equation is summarized in Appendix B.2 of the Tennessee Regional Haze submittal 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.*

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,[15] ODEQ calculated baseline visibility conditions for the Wichita Mountains. The baseline condition calculation begins with the calculation of light extinction, using the IMPROVE equation. The IMPROVE equation sums the light extinction [16] resulting from individual pollutants, such as sulfates and nitrates. As with the natural visibility conditions calculation, ODEQ 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). Although visibility monitoring only began at the Wichita Mountains in March 2001, ODEQ concluded that no other monitor provided a reasonable substitute that met our completeness criteria.[17] As a consequence, the Oklahoma RH SIP employed the incomplete visibility data for 2001, complete data for 2002–2004, and provisional data for 2005 and 2006. The resulting baseline conditions represent an average for 2002–2004. ODEQ calculated the baseline conditions at the Wichita Mountains as 23.81 deciviews on the 20 percent worst days, and 9.78 deciviews on the 20 percent best days. We have reviewed ODEQ's estimation of baseline visibility conditions at Wichita Mountains and propose to find it acceptable.

3. Natural Visibility Impairment

To address 40 CFR 51.308(d)(2)(iv)(A), ODEQ also calculated the number of deciviews by which baseline conditions exceed natural visibility conditions at the Wichita Mountains for the 20 percent worst days to be 16.28 dv (23.81 − 7.53). ODEQ calculated the baseline and natural visibility conditions on the 20 percent best days to be 9.78 and 4.2 dv, respectively. This results in a calculation in which baseline conditions exceed natural visibility conditions at the Wichita Mountains for the 20 percent best days to be 5.6 dv (9.78 − 4.2). We have reviewed ODEQ's estimate of the natural visibility impairment and propose to find it acceptable.

4. Uniform Rate of Progress

In setting the RPGs, ODEQ analyzed and determined the Uniform Rate of Progress (URP) needed to reach natural visibility conditions by the year 2064. In so doing, ODEQ compared the baseline visibility conditions in the Wichita Mountains to the natural visibility conditions in the Wichita Mountains (as described above) and determined the uniform rate of progress needed in order to attain natural visibility conditions by 2064. ODEQ constructed the URP consistent with 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 the Wichita Mountains. Using a baseline visibility value of 23.81 dv and a "refined" natural visibility value of 7.53 dv for the 20 percent worst days, ODEQ calculated the URP to be approximately 0.27 dv per year. This results in a total reduction of 16.28 dv that are necessary to reach the natural visibility condition of 7.53 dv in 2064. The URP results in a visibility improvement of 3.80 dv for the period covered by this SIP revision submittal (up to and including 2018).

TABLE 1—SUMMARY OF UNIFORM RATE OF PROGRESS

Baseline Conditions	23.81 dv.
Natural Visibility	7.53 dv.
Total Improvement by 2064	16.28 dv.
Improvement for this SIP by 2018.	3.80 dv.
Uniform Rate of Progress	0.27 dv/year.

We propose to find that ODEQ has appropriately calculated the URP.

C. Evaluation of Oklahoma's Reasonable Progress Goal

We are not taking action on Oklahoma's submitted RPGs because, as described more fully below, we must first evaluate and act upon the RH SIP revision submitted by the State of Texas. We provide a short summary of the Oklahoma submittal for informational purposes only.

1. Establishment of the Reasonable Progress Goal

ODEQ calculated the RPG for the Wichita Mountains for 2018 for the 20% best days to be 9.23 dv, which is a 0.54 dv improvement over a baseline of 9.78 dv. ODEQ calculated the reasonable progress goal for 2018 for the 20% worst days to be 21.47 dv, which is a 2.3 deciview improvement over a baseline of 23.81 dv. ODEQ's RPG establishes a slower rate of progress than the URP. ODEQ has calculated that under its reasonable progress goal, it would attain natural visibility conditions in 2102. As we discuss elsewhere, ODEQ indicated that emissions from other states, especially Texas, impeded Oklahoma's ability to meet the URP.

2. ODEQ's Reasonable Progress "Four Factor" Analysis

ODEQ analyzed the largest sources of visibility impairing pollutants within the state, including sources of sulfur, nitrates, ammonia, VOCs, and directly emitted coarse and fine particles. ODEQ calculated (1) that sulfurous pollutants contribute approximately 44% and nitrate bearing pollutants contribute approximately 21% of the total light extinction (or visibility impairment) to the Wichita Mountains, and (2) sources within Oklahoma contribute only approximately 13% of the total pollutants that contribute to light extinction.

ODEQ initially relied on CENRAP modeling, based on an Alpine Geophysics evaluation of possible additional point-source controls for CENRAP states for 2018. That study relied on AirControlNet, an EPA cost-benefit tool for emissions of NO_X and SO_2. CENRAP used a maximum estimated cost of $5,000 per ton of emissions of NO_X or SO_2 reduced for sources over 100 tons of SO_2 or NO_X in the year 2018. CENRAP further refined the analysis, considering controls only for those sources with emissions of NO_X or SO_2 greater than or equal to five tons per year per kilometer of distance to the Wichita Mountains or the nearest other Class I area. This analysis resulted in the conclusion by ODEQ that visibility at the Wichita Mountains would be improved by an additional 0.5 dv, over what ODEQ projects as its reasonable progress goal of 21.47 deciview for 2018 if controls were implemented at the sources that met this combination of baseline emissions, potential for cost-effective reductions, and visibility impact.

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

[16] 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).

[17] Guidance for Tracking Progress Under the Regional Haze Rule, EPA–454/B–03–004, September 2003, pages 2–8.

Following this analysis, ODEQ examined sources within Oklahoma that were not already being controlled via BART or consent decrees or other regulatory mechanisms. See the TSD for a listing of the sources considered. In so doing, ODEQ analyzed the cost of compliance by weighing the cost of potential pollution control equipment versus the visibility benefit. Based on this analysis, ODEQ concluded that no additional controls were required. ODEQ reasoned that most of the largest sources of SO_2 and NO_X were already being controlled through BART, already had adequate controls in place, or were too far from the Wichita Mountains (too little visibility impact) to justify the cost of additional controls.

3. Reasonable Progress Consultation

ODEQ used CENRAP as its main vehicle for facilitating collaboration with FLMs and other states in developing its RH SIP. ODEQ 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 the Wichita Mountains.

ODEQ invited those states projected through visibility modeling to contribute greater than 1 Mm^{-1} of light extinction at the Wichita Mountains in 2018 to consultations. ODEQ conducted four consultations. ODEQ directed its first consultation, to the tribal leaders in Oklahoma and their environmental managers, on 14 August 2007. ODEQ held the next three consultations as conference calls and invited CENRAP member clean air agencies, EPA, and the tribes to participate.

ODEQ received responses from the Arkansas Department of Environmental Quality, the Iowa Department of Natural Resources, and the Missouri Department of Natural Resources. These states concluded that emissions from within their borders do not significantly impact visibility at the Wichita Mountains, and they did not offer any additional reductions from their anthropogenic sources.

ODEQ has indicated and we agree that sources in Texas significantly affect the visibility at the Wichita Mountains. We note ODEQ communicated this to Texas in the correspondence included in Appendix 10–1, and Texas agreed with that assertion. However, ODEQ did not request any emission reductions from Texas. As a result of its correspondence with Texas, Texas agreed to provide ODEQ the opportunity to comment on Best Available Control Technology determinations for Prevention of Significant Deterioration sources that have significant impact on the Wichita Mountains. Specifically, ODEQ will be afforded the opportunity to review applications for sources if modeling predicts a five percent or higher impact on light extinction in a given year and provide comments to Texas during its public review and comment period. Texas also agreed to notify ODEQ whenever modeling indicates that a proposed source may significantly impact the Wichita Mountains. ODEQ also requested that Class I impact reviews be required for all proposed PSD sources within 300 kilometers of a Class I area. However, this request was not agreed to by Texas, who cited the need for EPA to adopt significant impact levels for Class I reviews so that there is a consistent approach to requiring Class I reviews.

In establishing its RPG, ODEQ is required by 40 CFR 51.308(d)(1)(i)(B) to consider the emission reduction measures needed to achieve the URP for the period covered by this SIP. Our 1999 RHR [18] further illuminates this requirement:

> [T]he State must identify the amount of progress that would result if this uniform rate of progress were achieved during the period of the first regional haze implementation plan.
>
> [T]he State must identify and analyze the emissions measures that would be needed to achieve this amount of progress during the period covered by the first long-term strategy, and to determine whether those measures are reasonable based on the statutory factors. These factors are the costs of compliance with the measures, the time necessary for compliance with the measures, the energy and nonair quality environmental impacts of the compliance with the measures, and the remaining useful life of any existing source subject to the measures. In doing this analysis, the State must consult with other States which are anticipated to contribute to visibility impairment in the Class I area under consideration. Because haze is a regional problem, States are encouraged to work together to develop acceptable approaches for addressing visibility problems to which they jointly contribute. If a contributing State cannot agree with the State establishing the reasonable progress goal, the State setting the goal must describe the actions taken to resolve the disagreement.

[18] 64 FR 35732.

As further explained by the RHR,[19] Oklahoma was under an additional obligation to consider these controls as part of its reasonable progress analysis requirement:

> If the State determines that the amount of progress identified through the 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.

We note that as part of its RH SIP submittal, Texas did consider the impact its sources have on the visibility of the Wichita Mountains. Therefore, we believe that to properly assess whether Oklahoma has satisfied the reasonable progress requirements of section 51.308(d)(1), we must review and evaluate Texas' submittal. We will do this in the course of processing the Texas RH SIP.

D. Evaluation of Oklahoma's BART Determinations

Oklahoma's submitted BART rule, OAC 252:100–8, Part 11, became effective on June 15, 2007. Definitions related to the BART rule were added in the Air Quality Rules general definitions section in OAC 252:100–8.1.1, and became effective as a permanent rule on June 15, 2006. These submitted rules also incorporate by reference 40 CFR part 51, appendix Y (our BART Guidelines). The rules further provide that the resulting source-specific requirements be incorporated into that source's air quality permit.

BART is an element of Oklahoma's LTS for the first implementation period. As discussed in more detail in section IV.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. ODEQ 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. ODEQ identified the BART-eligible sources in Oklahoma by utilizing the three eligibility criteria in the BART Guidelines (70 FR 39158) and our

[19] Id.

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) was constructed on or after August 6, 1962, and was in existence prior to August 6, 1977; and (3) potential emissions of any visibility-impairing pollutant from subject units are 250 tons or more per year. ODEQ initially screened its emissions inventory and permitting database to identify major facilities with emission units in one or more of the 26 BART categories. Following this, ODEQ used its databases and records to identify facilities in these source categories with potential emissions of 250 tons per year or more for any visibility-impairing pollutant from any unit that was in existence on August 7, 1977 and began operation after August 7, 1962. ODEQ contacted the sources, when necessary, to obtain or confirm this information.

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-impairment 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 the Wichita Mountains. Ammonia emissions in Oklahoma are primarily due to area sources, such as livestock and fertilizer application. Because these are not point sources, they are not subject to BART.[20] ODEQ did consider ammonia from point sources. The emissions inventory prepared for the CENRAP modeling demonstrates that ammonia from point sources are not significant visibility-impairing pollutants in Oklahoma. ODEQ further argued that because of the limiting role of NO_X and SO_2 on $PM_{2.5}$ formation and the uncertainties in assessing the effect of an individual source's ammonia emissions reductions on visibility, it did not consider ammonia among visibility-impairing pollutants. We have reviewed this information and propose to agree with this decision.

Table 2 lists Oklahoma's BART-eligible sources:

TABLE 2: FACILITIES WITH BART-ELIGIBLE UNITS IN OKLAHOMA

BART source category	Facility name	County	Number of units
Fossil fuel-fired boilers of more than 250 MMBTU/hr heat input.	Georgia Pacific Consumer Products (formerly Fort James Operating) Muskogee Mill.	Muskogee	2
Kraft pulp mill	International Paper (formerly Weyerhaeuser) Valliant Paper Mill.	McCurtain	4
Hydrofluoric, sulfuric, and nitric acid plants	Koch Nitrogen Enid Plant	Garfield	7
	Terra International Oklahoma Woodward Complex	Woodward	11
	Terra Nitrogen Partnership Verdigris Plant	Rogers	12
Petroleum refineries	Sinclair Oil Tulsa Refinery	Tulsa	7
	Holly Refining and Marketing (formerly Sunoco) Tulsa Refinery.	Tulsa	25
	Wynnewood Refining	Garvin	14
	Valero Refinery (formerly TPI Petroleum Inc) Ardmore Refinery.	Carter	24
Portland cement plants	Lafarge Building Materials Tulsa Rogers City Line	Rogers	10
Fossil fuel-fired steam electric plants of more than 250 MMBTU/hr heat input.	OG&E Horseshoe Lake Generating Station	Oklahoma	2
	OG&E Muskogee Generating Station	Muskogee	2
	OG&E Seminole Generating Station	Seminole	3
	OG&E Sooner Generating Station	Noble	2
	PSO Comanche Power Station	Comanche	2
	PSO Northeastern Power Station	Rogers	3
	PSO Riverside Jenks Power Station	Tulsa	2
	PSO Southwestern Power Station	Caddo	1
	Western Farmers Electric Coop Anadarko Plant	Caddo	3
	Western Farmers Electric Coop Mooreland Station	Woodward	3

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, ODEQ 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.

a. Modeling Methodology

The BART Guidelines provide that states may choose to use the CALPUFF[21] modeling system or another appropriate model to predict the visibility impacts from a single source on a Class I area and to therefore,

[20] ODEQ took the position, and we agree, that it is not practical at this time to control ammonia from these types of sources, for the purpose of improving visibility under the reasonable progress requirements of section 51.308(d)(1).

[21] 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.*

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). ODEQ, in coordination with CENRAP, used the CALPUFF modeling system to determine whether individual sources in Oklahoma 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 Oklahoma, developed the "CENRAP BART Modeling Guidelines".[22] Stakeholders, including 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 indicates, therefore sources were evaluated using the 1st High values instead of the 8th High values. The use of the 1st High was agreed to by EPA, representatives of the Federal Land Managers, and CENRAP stakeholders. Some sources that did not screen out did later conduct refined CALPUFF modeling that incorporated meteorological data with observations and which allowed to them to compare 8th High modeling values with the 0.5 deciview threshold. We propose to find the chosen model and the general modeling methodology acceptable. However, we note a few additional deviations from modeling guidance that are discussed in the TSD and addressed in our remodeling of visibility impacts in support of the FIP for these six sources.

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. ODEQ used a contribution threshold of 0.5 dv for determining which sources are subject to BART. There are a limited number of BART-eligible sources in close proximity to the State's Class I area and surrounding Class I areas, and the results of the visibility impacts modeling demonstrated that the majority of the individual BART-eligible sources had visibility impacts well below 0.5 dv. We agree with the State's rationale for choosing this threshold value.

c. BART Sources Exempted Due to Permit Modifications

When performing its initial BART screening modeling, ODEQ identified three sources with a contribution of greater than 0.5 deciviews in visibility impairment that desired to limit their emissions in order to avoid a BART determination. These sources were (1) the Georgia Pacific Consumer Products LP, Muskogee Mill; (2) the International Paper, Valliant Paper Mill; and (3) the Western Farmers Electric Coop, Anadarko Plant. An updated BART modeling analysis, assuming those controls were in place, demonstrated a contribution of less than 0.5 deciview of visibility impairment for each of these facilities. They are individually discussed below. ODEQ issued a Title V operating permit to each of the sources that imposed an emission limitation requiring the modeled controls. Since these three sources are voluntarily taking limits to avoid a full BART analysis, any future changes or relaxation of these limits at these specific BART-eligible units or in their permits that would allow for increases in SO_2, NO_X, or PM emissions would subject those sources to BART review, pursuant to the submitted ODEQ rules that we propose to approve as part of the Oklahoma RH SIP.

i. Georgia Pacific Consumer Products LP, Muskogee Mill

The Georgia Pacific, Muskogee Mill had two BART eligible boilers, Boiler B–1 and Boiler B–2. Georgia Pacific requested of ODEQ that an enforceable emission limit be imposed on Boiler B–1 to maintain emissions below the BART contribution threshold of 0.5 deciviews. Where previously Boiler B–1 was permitted to burn either No. 2 fuel oil or natural gas, Boiler B–1 is now restricted to burning natural gas, which will reduce its NO_X emissions. ODEQ has determined that under the Title V operating permit modification, this facility will have a visibility impairment contribution of less than 0.5 deciviews at any Class I area, which is below the contribution threshold used by ODEQ in their BART analyses. This emission reduction is housed in a modification to the facility's Oklahoma Department of Environmental Quality, Air Quality Division operating Permit, No. 99–113–TV (M–5), issued January 5, 2011. This permit requires that this fuel switch be operational no more than five years following our final action on the Oklahoma RH SIP.

ii. International Paper, Valliant Paper Mill

The International Paper, Valliant Paper Mill has three BART eligible boilers: EUG D1, Bark Boiler; EUG D2, Power Boiler; and EUG D3, Package Boiler. It also has a BART eligible Lime Kiln, EUG E7a. The Valiant Paper Mill has accepted limits on the sulfur content of fuel to the Bark and Power boilers in order to reduce its visibility impact. ODEQ has determined that under this Title V operating permit modification, this facility will have a visibility impairment contribution of less than 0.5 deciviews at any Class I area, which is below the contribution threshold used by ODEQ in their BART analyses. This emission reduction is housed in a modification to the facility's Oklahoma Department of Environmental Quality, Air Quality Division operating Permit No. 97–057–TV (M–10), issued March 24, 2010. This permit requires these controls be operational no more than five years following our final action on the Oklahoma RH SIP.

iii. Western Farmers Electric Coop, Anadarko Plant

The Western Farmers Electric Coop (WFEC), Anadarko facility had three

[22] 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.*

BART eligible combine cycle gas turbines, AN–Unit 4, AN–Unit 5, and AN–Unit 6. WFEC agreed to NO_X, SO_2, and PM–10 emission limits on the combined cycle gas turbines in order to reduce their visibility impact. ODEQ has determined that under this Title V operating permit modification, this facility will have a visibility impairment contribution of less than 0.5 deciviews at any Class I area, which is below the contribution threshold used by ODEQ in their BART analyses. This emission reduction is housed in a modification to the facility's Oklahoma Department of Environmental Quality, Air Quality Division operating Permit, No. 2005–037–TVR (M–1), issued July 9, 2010. This permit will require these controls be operational no more than five years following our final action on the Oklahoma RH SIP.

d. Sources Identified by ODEQ as Subject to BART

Following the elimination of those sources that were found to have visibility impacts below the 0.5 deciview threshold, or the three discussed in the previous section that received Title V permits limiting their visibility impact below the 0.5 deciview threshold, ODEQ identified the sources contained in Table 3 as being subject to BART.

TABLE 3—SOURCES IN OKLAHOMA SUBJECT TO BART

Facility name	BART emission units	Source category	Pollutants evaluated
OG&E Seminole	Units 1, 2, and 3	fossil fuel-fired steam electric plants	NO_X
OG&E Sooner	Units 1 and 2	fossil fuel-fired steam electric plants	SO_2 NO_X PM_{10}
OG&E Muskogee	Units 4 and 5	fossil fuel-fired steam electric plants	SO_2 NO_X PM_{10}
AEP/PSO Comanche	Units 1 and 2	fossil fuel-fired steam electric plants	NO_X
AEP/PSO Northeastern	Unit 2	fossil fuel-fired steam electric plants	NO_X
AEP/PSO Northeastern	Units 3 and 4	fossil fuel-fired steam electric plants	SO_2 NO_X PM_{10}
AEP/PSO Southwestern	Unit 3	fossil fuel-fired steam electric plants	NO_X

3. BART Determinations

The third step of a BART evaluation is to perform the BART analysis. The BART Guidelines [23] 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.

All of the sources that are subject to BART presented in Table 3 are fossil fuel fired electricity generating units. ODEQ performed BART determinations for all of these sources for NO_X, SO_2, and PM. For each BART determination, we find that ODEQ adequately considered Steps 1 through 5, above, except for the SO_2 BART determinations for Units 4 and 5 of the OG&E Muskogee plant, Units 1 and 2 of the OG&E Sooner plant, and Units 3 and 4 of the AEP/PSO Northeastern plants. The SO_2 BART determinations for these six units are the subject of our FIP and are treated separately in Section V.E. of this proposal. We agree with ODEQ's BART determinations for all remaining cases and summarize them below. For more details, please see the TSD.

a. OG&E Seminole Units 1, 2, and 3 BART Determinations

The OG&E Seminole Units 1, 2 and 3 are BART-eligible sources. These units are gas fired boilers with gross outputs of 567 MW each. ODEQ considered all NO_X control technologies, including combustion controls such as Low NO_X Burners (LNB) and Flue Gas Recirculation (FGR); and post combustion controls, such as Selective Catalytic Reduction (SCR), and Selective Noncatalytic Reduction (SNCR). ODEQ concluded that LNB/OFA +SCR, LNB/OFA +FGR, and LNB/OFA were technically feasible. ODEQ then evaluated the economic, environmental, and energy impacts associated with the three proposed control options. This included CALPUFF visibility modeling, based on a modeling protocol we find acceptable. ODEQ determined that the installation of new LNB with OFA and FGR was cost effective, with a capital cost of $16,977,200 per unit for units 1 and 2 and $9,468,600 for unit 3 and an average cost effectiveness of $1,554–$2,120 per ton of NOx removed for each unit over a twenty year operational life. ODEQ determined that NO_X BART emission limits should be 30-day rolling averages of 0.203 lb/MMBtu for Unit 1, 0.212 lb/MMBtu for Unit 2 and 0.164 lb/MMBtu for Unit 3. The BART Guidelines do not specify a presumptive NO_X BART limit for gas fired power plants. As Units 1, 2, and 3 are gas fired, ODEQ determined that SO_2 and PM BART for them are no additional control. We propose to approve ODEQ's determination of BART for the OG&E Seminole Units 1, 2, and 3.

b. OG&E Sooner Units 1 and 2 BART Determinations

The OG&E Sooner Units 1 and 2 are BART-eligible sources. Both units are coal fired with a gross output of 570 MW. We evaluate ODEQ's SO_2 BART determinations for Units 1 and 2 in section V.E. Here we discuss our review of ODEQ's NO_X and PM BART determination for these units.

ODEQ considered all NOx control technologies, including combustion controls such as LNB and FGR; and post combustion controls, such as SCR, and SNCR. ODEQ concluded that LNB/OFA +SCR, and LNB/OFA were technically feasible. ODEQ noted that FGR control systems have been used as a retrofit NO_X control strategy on natural gas-fired boilers, but have not generally been considered as a retrofit control technology on coal-fired units. ODEQ then evaluated the economic, environmental, and energy impacts associated with the two proposed control options. This included CALPUFF visibility modeling, based on a modeling protocol we find acceptable.

[23] 70 FR 39164.

For Units 1 and 2, ODEQ determined the installation of new LNB with OFA was cost effective, with a capital cost of $14,055,900 per unit for units 1 and 2 and an average cost effectiveness of $493–785 per ton of NO_X removed for each unit over a twenty-five year operational life. ODEQ determined that NO_X BART emission limits should be 30-day rolling averages of 0.15 lbs/MMBtu, which meets the BART presumptive limit.

For PM, ODEQ noted there are two generally recognized PM control devices that are used to control PM emission from coal fired boilers, which are Electrostatic Precipitators (ESPs) and fabric filters (or baghouses). Sooner Units 1 & 2 are currently equipped with ESP control systems. ODEQ determined that although fabric filters offer a slight improvement in PM control (99.7 versus 99.3 percent control), their additional cost did not justify the modest improvement in PM control. ODEQ determined PM BART is the existing ESPs with an emission rate of 0.1 lbs/MMBtu on a 3-hour average. ODEQ specified additional BART emission limitations in lbs/hour and tons/year. We propose to approve ODEQ's PM and NO_X BART determinations for the OG&E Sooner Units 1 and 2.

c. OG&E Muskogee Units 4 and 5 BART Determinations

The OG&E Muskogee Units 4 and 5 are BART-eligible sources. Both units are coal fired with a gross output of 572 MW. We evaluate ODEQ's SO_2 BART determinations for Units 4 and 5 in section V.E. Here we discuss our review of ODEQ's NO_X and PM BART determination for these units.

ODEQ considered all NO_X control technologies, including combustion controls such as LNB and FGR; and post combustion controls, such as SCR, and SNCR. ODEQ concluded that LNB/OFA +SCR, and LNB/OFA were technically feasible. ODEQ noted that FGR control systems have been used as a retrofit NO_X control strategy on natural gas-fired boilers, but have not generally been considered as a retrofit control technology on coal-fired units. ODEQ then evaluated the economic, environmental, and energy impacts associated with the two proposed control options. This included CALPUFF visibility modeling, based on a modeling protocol we find acceptable. For Units 4 and 5, ODEQ determined the installation of new LNB with OFA was cost effective, with a capital cost of $14,113,700 per unit for units 4 and 5 and an average cost effectiveness of $260–$281 per ton of NO_X removed for each unit over a twenty-five year operational life. ODEQ determined that NO_X BART emission limits should be 30-day rolling averages of 0.15 lbs/MMBtu, which meets the BART presumptive limit.

For PM, ODEQ noted there are two generally recognized PM control devices that are used to control PM emission from coal fired boilers, which are Electrostatic Precipitators ESPs and fabric filters (or baghouses). Muskogee Units 4 & 5 are currently equipped with ESP control systems. ODEQ determined that although fabric filters offer a slight improvement in PM control (99.7 versus 99.3 percent control), their additional cost did not justify the modest improvement in PM control. ODEQ determined PM BART is the existing ESPs with an emission rate of 0.1 lbs/MMBtu on a 3-hour average. ODEQ specified additional BART emission limitations in lbs/hour and tons/year. We propose to approve ODEQ's PM and NO_X BART determinations for the OG&E Muskogee Units 4 and 5.

d. AEP/PSO Comanche Units 1 and 2 BART Determinations

The AEP/PSO Comanche Units 1 and 2 are BART-eligible sources. These units are gas fired turbines with duct burners and heat recovery steam generators with a gross output of 94 MW each.

For Units 1 and 2, ODEQ considered dry LNBs and SCR as being possibly applicable to gas fired turbines. ODEQ concluded that due to specific design considerations, only dry LNBs were technically feasible. ODEQ then evaluated the economic, environmental, and energy impacts associated with that proposed control option. This included CALPUFF visibility modeling, based on a modeling protocol we find acceptable. ODEQ determined that the installation of dry LNBs was cost effective, with a capital cost of $34,660,000 an average cost effectiveness of $2,600 per ton of NO_X removed for each unit over a twenty year operational life. ODEQ determined that NO_X BART emission limits should be 30-day rolling averages of 0.15 lbs/MMBtu. The BART Guidelines do not specify a presumptive NO_X BART limit for gas fired power plants. As Units 1 and 2 are gas fired, ODEQ determined that SO_2 and PM BART for them are no additional control. We propose to approve ODEQ's determination of BART for the AEP/PSO Comanche Units 1 and 2.

e. AEP/PSO Northeastern Unit 2, 3, and 4 BART Determination

The AEP/PSO Northeastern Units 2, 3, and 4 are BART-eligible sources. Unit 2 is a gas fired boiler with a gross output of 495 MW. Units 3 and 4 are coal fired with gross outputs of 490 MW each. We evaluate ODEQ's SO_2 BART determinations for Units 3 and 4 in section V.E. Here we discuss our review of ODEQ's NO_X and PM BART determination for these units.

For Unit 2, ODEQ considered all NO_X control technologies, including combustion controls such as LNB and FGR; and post combustion controls, such as SCR, and SNCR. ODEQ concluded that LNB/OFA +SCR, LNB/OFA +FGR, and LNB/OFA were technically feasible. ODEQ then evaluated the economic, environmental, and energy impacts associated with the three proposed control options. This included CALPUFF visibility modeling, based on a modeling protocol we find acceptable. ODEQ determined that the installation of new LNB with OFA was cost effective, with a capital cost of $3,450,000 and an average cost effectiveness of $303 per ton of NO_X removed over a twenty year operational life. ODEQ determined that NO_X BART emission limits should be 30-day rolling averages of 0.28 lbs/MMBtu. ODEQ specified additional BART emission limitations in lbs/hour and tons/year. The BART Guidelines do not specify a presumptive NO_X BART limit for gas fired power plants. As Unit 2 is gas fired, ODEQ determined that SO_2 and PM BART for it are no additional control. We propose to approve ODEQ's determination of BART for the AEP/PSO Northeastern Unit 2.

For Units 3 and 4, ODEQ considered all NO_X control technologies, including combustion controls such as LNB and FGR; and post combustion controls, such as SCR, and SNCR. ODEQ concluded that LNB/OFA +SCR, LNB/OFA, were technically feasible. ODEQ noted difficulties posed by the installation of SNCR on Units 3 and 4 but did evaluate SNCR. ODEQ noted that FGR control systems have been used as a retrofit NO_X control strategy on natural gas-fired boilers, but have not generally been considered as a retrofit control technology on coal-fired units. ODEQ then evaluated the economic, environmental, and energy impacts associated with the two proposed control options. This included CALPUFF visibility modeling, based on a modeling protocol we find acceptable. For Units 3 and 4, ODEQ determined the installation of new LNB with OFA was cost effective, with a capital cost of $17,000,000 and an average cost effectiveness of $313 per ton of NO_X removed over a twenty-five year operational life. ODEQ determined that NO_X BART emission limits should be 30-day rolling averages of 0.15 lbs/

MMBtu, which meets the BART presumptive limit.

For PM, ODEQ noted there are two generally recognized PM control devices that are used to control PM emission from coal fired boilers, which are ESPs and fabric filters (or baghouses). Northeastern Units 3 & 4 are currently equipped with ESP control systems. ODEQ determined that although fabric filters offer a slight improvement in PM control (99.7 versus 99.3 percent control), their additional cost did not justify the modest improvement in PM control. ODEQ determined PM BART is the existing ESPs with an emission rate of 0.1 lbs/MMBtu on a 3-hour average. ODEQ specified additional BART emission limitations in lbs/hour and tons/year. We propose to approve ODEQ's determination of BART for the AEP/PSO Northeastern Units 3 and 4.

f. AEP/PSO Southwestern Unit 3 BART Determination

The AEP/PSO Southwestern Unit 3 is a BART-eligible source. This unit is a gas fired boiler with a gross output of 332 MW. ODEQ considered all NO_X control technologies, including combustion controls such as LNB and FGR; and post combustion controls, such as SCR, and SNCR. ODEQ concluded that LNB/OFA +SCR, and LNB/OFA were technically feasible. ODEQ then evaluated the economic, environmental, and energy impacts associated with the three proposed control options. This included CALPUFF visibility modeling, based on a modeling protocol we find acceptable. ODEQ determined that the installation of new LNB with OFA was cost effective, with a capital cost of $3,000,000 and an average cost effectiveness of $947 per ton of NO_X removed over a twenty-year operational life. ODEQ determined that NO_X BART emission limits should be 30-day rolling averages of 0.45 lbs/MMBtu on a 30-day average. ODEQ specified additional BART emission limitations in lbs/hour and tons/year.

The BART Guidelines do not specify a presumptive NO_X BART limit for gas fired power plants. However, due to the relatively high NO_X emission rate that ODEQ determined was BART, and the fact that it appeared the annual average emissions rates recorded with the Clean Air Markets Division indicates that the boiler can currently comply with the standard on an annual average basis, we asked for additional information. ODEQ responded with data detailing 9 years of emissions versus load, that indicate that the boiler operates through a range where emissions can reach as much as 1.4 lb/MMBtu at full load. This unit has historically operated as a "peaking unit" responding to increased demand for electricity. While technically feasible, LNB/OFA may not be as effective under all boiler operating conditions, especially during load changes and at low and high operating loads. After having examined the data, attached in our TSD, we accept ODEQ's explanation. As Unit 3 is gas fired, ODEQ determined that SO_2 and PM BART for it are no additional control. We propose to approve ODEQ's determination of BART for the AEP/PSO Southwestern Unit 3.

g. ODEQ BART Results and Summary

We have reviewed ODEQ's BART determinations for the sources listed in Table 3, above. We note that these BART determinations result in significant reductions in the amount of NO_X that will be emitted by these sources, totaling 27,043 tons per year. This results in significant visibility benefits at the Wichita Mountains, Caney Creek, Upper Buffalo, and Hercules Glades Class I areas. Calculated as the 3-year average of the modeled visibility improvement at the 98th percentile, these NO_X BART reductions result in a visibility improvement of 5.46 dv at the Wichita Mountains, 2.65 deciviews at Caney Creek, 1.79 dv at the Upper Buffalo, and 1.37 dv at Hercules Glades. This results in an 11.27 dv improvement over all these Class I areas. See the TSD for more details.

Oklahoma's BART rule requires each source subject to BART to install and operate BART no later than 5 years after we approve this RH SIP. OAC 252–100–8–75(e). Therefore, we believe this satisfies ODEQ's obligation under section 51.308(e)(1)(iv), that "each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision."

For the reasons discussed above, we propose to find that with the exception of the SO_2 BART determinations for Units 4 and 5 of the OG&E Muskogee plant, Units 1 and 2 of the OG&E Sooner plant, and Units 3 and 4 of the AEP/PSO Northeastern plants, ODEQ has satisfied the BART requirement of section 51.308(e).

E. Evaluation of ODEQ's SO_2 BART Determinations for the OG&E and AEP/PSO Coal Fired Power Plant Units

The discussion below is limited to the SO_2 BART assessments for Units 4 and 5 of the Oklahoma Gas and Electric Muskogee plant, Units 1 and 2 of the Oklahoma Gas and Electric Sooner plant (the "OG&E units"), and Units 3 and 4 of the American Electric Power/Public Service Company of Oklahoma Northeastern plant (the "AEP/PSO units"). ODEQ's other BART assessments are covered in Section V.D., above.

In the Oklahoma RH SIP submittal, ODEQ concluded that dry flue gas desulfurization with spray dryer absorbers ("dry scrubbers") and wet flue gas desulfurization ("wet scrubbers") were not cost effective for these units. ODEQ came to this decision after comparing the cost effectiveness in annualized dollars per ton of SO_2 removed ($/ton) to the visibility improvement at the nearest Class I areas. ODEQ determined that SO_2 BART for these units was no control and specified an SO_2 limit of 0.65 lbs/MMBtu on a 30-day rolling average. The OG&E units currently burn a low sulfur coal from the Powder River Basin (PRB) of Wyoming, and already have historical annual emission rates significantly below this limit. Therefore, it is possible the OG&E units would be able to actually increase their emissions slightly, and still be in compliance with ODEQ's SO_2 BART assessment. The AEP/PSO units have historical annual emission rates that have been steadily decreasing to a point where the imposition of ODEQ's proposed BART SO_2 emission rate of 0.65 lbs/MMBtu would result in very little reduction in emissions. Below we discuss ODEQ's BART evaluation and our assessment of that evaluation.

1. Cost Effectiveness

We propose to find that ODEQ properly identified these sources as BART eligible, in compliance with section 51.308(e)(1)(i). However, we propose to find that ODEQ did not properly follow the requirements of section 51.308(e)(1)(ii)(A) in determining BART. Specifically, we propose that ODEQ did not properly "take into consideration the costs of compliance" when it relied on cost estimates that greatly overestimated the costs of dry and wet scrubbing to conclude these controls were not cost effective. Given that scrubbers are typically considered to be highly cost-effective controls for power plants such as those at issue, we retained a consultant to independently assess the suitability and costs of installing these controls. We have thoroughly reviewed and evaluated the consultant's report and agree with its findings regarding the cost-effectiveness of dry and wet scrubbing at the BART units. Our consultant's detailed report has been incorporated into the TSD.[24]

a. Dry Scrubbing Cost Analyses

Table 4, below, summarizes and contrasts the cost effectiveness of dry scrubbers estimated by ODEQ[25] versus our estimate. Both ODEQ and we used BART evaluations performed by OG&E and AEP/PSO as the starting points for the assessments.[26]

TABLE 4—CONTRAST OF DRY SCRUBBER COST EFFECTIVENESS

Plant	ODEQ projected cost ($/ton SO_2 removed)	EPA's projected cost ($/ton SO_2 removed)
Sooner 1	$6,348	$1,291
Sooner 2	7,147	1,291
Muskogee 4	7,378	1,317
Muskogee 5	7,493	1,317
Northeastern 3	3,294	1,544
Northeastern 4	3,294	1,544

Although our TSD provides a detailed comparison between the costing methodologies, a few general points can be made that explain why our costs differ with those from ODEQ. First, in the case of the OG&E analyses, a coal with a significantly higher sulfur content than is currently burned was assumed by OG&E's contractor in determining the design of the scrubber. This increased the capital cost of the scrubber over what would minimally be needed to scrub the coal currently being burned. However, the increased tonnage of SO_2 that would have been removed from the emissions resulting from the burning of that coal, and the high efficiency of the scrubber was not used in calculating the cost effectiveness ($/ton). Our cost analysis, assumed the same higher sulfur coal, but adjusted the cost effectiveness to account for the increased scrubber efficiency and the increased tonnage of sulfur that would be removed. Second, the companies did not follow the Air Pollution Control Cost Manual[27] when possible, as specified in the BART guidelines.[28] Our cost analysis does follow the Air Pollution Control Cost Manual. Third, some costs were significantly outside of the range of the actual costs. In our analysis these costs are adjusted accordingly. Fourth, the cost estimates contained double counting. In our analysis, the double counted costs are removed. Lastly, the cost estimates failed to evaluate the most cost effective options. Our analysis accounts for the more cost effective options and is referred to as "Option 1" in our consultant's report.

However, even though it appeared that costing the larger scrubber was OG&E's preferred option, we did not wish to propose our decision solely on that basis. We also considered whether it would be cost effective to scrub the type of coal currently burned at the units. Therefore, we also analyzed the cost of a dry scrubber for the OG&E units, assuming the scrubber would be sized to scrub the coal being currently burned. This approach, referred to as "Option 2" in our consultant's report, is summarized in Table 5, below. The estimates in Table 5 are not refined estimates and did not consider all of the issues considered in option 1.

TABLE 5—UNREFINED MINIMALLY-SIZED OG&E DRY SCRUBBER COST EFFECTIVENESS

Plant	EPA's Projected Cost (Unrefined) ($/ton SO_2 removed)
Sooner 1	$4,594
Sooner 2	4,594
Muskogee 4	5,102
Muskogee 5	5,102

We further refined the cost of the smaller scrubber to account for the issues discussed above that were rectified in Option 1: not following the Air Pollution Control Cost Manual, adjusting costs that were outside of the range of the actual costs, eliminating double counted costs, and failing to evaluate the most cost effective options. Additional details concerning this refinement are covered in our TSD.

TABLE 6—REFINED MINIMALLY-SIZED OG&E DRY SCRUBBER COST EFFECTIVENESS

Plant	EPA's Projected Cost (Refined) ($/ton SO_2 removed)
Sooner 1	$2,048
Sooner 2	2,048
Muskogee 4	2,366
Muskogee 5	2,366

In contrasting the results displayed in Tables 4 and 6, we conclude that based on a controlled emission limit of 0.06 lbs/MMBtu, a dry scrubber is cost effective at Units 4 and 5 of the OG&E Muskogee plant, Units 1 and 2 of the OG&E Sooner plant, and Units 3 and 4 of the AEP/PSO Northeastern plant. In OG&E's case, this is true regardless of whether the scrubber is sized to control the coal presently burned, or a significantly dirtier coal. Therefore, we propose to find that we cannot accept the cost estimates for dry scrubbers provided in the Oklahoma RH submission.

b. Wet Scrubbing Cost Analyses

Table 7, below summarizes and contrasts the cost effectiveness of wet scrubbers estimated by ODEQ versus our estimates:

[24] Dr. Phyllis Fox, Revised BART Cost-Effectiveness Analysis for Flue Gas Desulfurization at Coal-Fired Electric Generating Units in Oklahoma: Sooner Units 1 & 2 Muskogee Units 4 & 5 Northeastern Units 3 & 4. Report Prepared for U.S. EPA, RTI Project Number 0209897.004.085.

[25] ODEQ BART analyses housed in Appendix 6–4 of the OK RH SIP.

[26] Sargent & Lundy, Sooner Units 1 & 2, Muskogee Units 4 & 5 Dry FGD BART Analysis Follow-Up Report, Prepared for Oklahoma Gas & Electric, December 28, 2009.

Trinity Consultants, Best Available Retrofit Technology (BART) Determination, American Electric Power, Northeastern Power Plant, May 30, 2008.

[27] U.S. EPA, EPA Air Pollution Control Cost Manual, EPA/452/B–02–001, 6th Ed., January 2002. The EPA Air Pollution Control Cost Manual was formerly known as the OAQPS Control Cost Manual.

[28] As stated in the BART guidelines, "[i]n order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual, where possible." 70 FR 39104, 39166.

TABLE 7—CONTRAST OF WET SCRUBBER COST EFFECTIVENESS

Plant	ODEQ projected cost ($/ton SO_2 removed)	EPA's projected cost ($/ton SO_2 removed)
Sooner 1	$6,998	$1,555
Sooner 2	7,827	1,555
Muskogee 4	8,724	1,417
Muskogee 5	8,852	1,417
Northeastern 3	3,625	1,699
Northeastern 4	3,625	1,699

The ODEQ's BART analyses eliminated wet scrubbing, in part, because the dollars per ton cost effectiveness was calculated to be higher than for dry scrubbing; the incremental cost to go from dry to wet scrubbing was judged unacceptable; and wet scrubbing was alleged to have certain adverse impacts that dry scrubbing did not have. ODEQ determined that wet scrubbing was not BART for SO_2 for any of the subject units. This determination was based in part, on several alleged adverse collateral impacts including: (1) Increased sulfuric acid mist (SAM) in the flue gas; (2) excess particulate emitted due to the location of a scrubber downstream of the particulate control device; (3) the need for more reactant, which would generate more fugitive dust; (4) the need for significantly more water; (5) the generation of a wastewater stream that must be treated; and (6) the creation of a higher visibility impairment due to lower exit velocity, lower stack temperature, and higher SAM emissions. We have determined these claims are either wrong or overstated. Furthermore, we noted several benefits of wet scrubbing and some drawbacks to dry scrubbing, which were not evaluated by ODEQ. These issues are detailed in our consultant's report. Please see the TSD for further discussion of our evaluation of ODEQ's determination that wet scrubbing was not BART for SO_2.

Although OG&E's contractor did not evaluate wet scrubbing in its final updated BART analyses, ODEQ modified an earlier OG&E wet scrubber cost estimate as the basis for estimating the cost of wet scrubbing. The total capital requirement for wet scrubbers was carried forward from the previous cost estimate. ODEQ then modified other costing parameters to be consistent with OG&E's contractor's current dry scrubber cost estimate. These modifications included the capital recovery factor, the annual operating costs, and administrative costs. AEP/PSO's contractor did provide a wet scrubber cost analysis as part of its BART analyses, which was incorporated into ODEQ's BART analysis. However, ODEQ's wet scrubber BART analyses for the OG&E and AEP/PSO plants did not include the kind of detailed, line-by-line cost breakdown that is needed for a proper evaluation.

We approached this problem by comparing the cost of wet to dry scrubbing for 13 cost effectiveness analyses (including the earlier OG&E analyses and the AEP/PSO analyses). The results of this analysis indicated that the average calculated cost effectiveness of a wet scrubber is typically about 9% higher than for a dry scrubber, except in those cases where an existing ESP can substitute for a new baghouse. Although that specific option was not evaluated or assumed in our cost analyses, we note that the OG&E and AEP/PSO units in question all have existing ESPs, and we expect they could be retained to reduce the cost. After increasing the cost of our calculated dry scrubbing estimate by 9%, we propose to find that the cost of wet scrubbing for the OG&E and AEP units fall within the range of values found to be cost effective in other similar wet scrubber cost determinations. As we stated in the BART Rule, "[a] reasonable range would be a range that is consistent with the range of cost effectiveness values used in other similar permit decisions over a period of time." 70 FR 39104, 39168. Dry scrubbers are being successfully applied to many kinds of stationary sources worldwide, including many similar applications in the utility industry.[29] As explained in the preamble to the BART Guidelines in explaining the decision to establish presumptive BART limits for SO_2 based on the use of scrubbers, both wet and dry scrubbers are highly cost effective for power plants, with costs of $400 to $2000 per ton of SO_2 removed typically. 70 FR at 39132. Thus, dry scrubbing is clearly cost effective, barring an unusual, site specific condition. However, neither OG&E nor AEP/PSO identified any such conditions. Similarly, wet scrubbing has been employed in many coal fired power plants in the United States, and is in fact more widely used than dry scrubbing. This includes the Pleasant Prairie Units 1 and 2 in Wisconsin, which are similar to the OG&E and AEP/PSO units in question.[30] Therefore, because our cost effectiveness calculations for the BART units fall within the range for other similar scrubber installations, we propose to find that both dry and wet scrubbing are cost effective in terms of dollars per tons of SO_2 removed. Consequently, we propose to disapprove ODEQ's evaluation of the cost effectiveness of control.

2. Visibility Benefit

Having considered the cost effectiveness of wet and dry scrubbers for OG&E and AEP/PSO, we then considered the visibility improvement that would result from the installation of controls. As was done in assessing costs, OG&E and AEP assessed visibility on a facility basis. ODEQ[31] used the CALPUFF modeling system, which 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. The modeling analysis generally followed the BART protocol developed by CENRAP.[32] In ODEQ's modeling approach, CALPUFF visibility modeling for each pollutant was carried out separately so that only NO_X emissions were modeled in support of the NO_X

[29] Electric Power Research Institute (EPRI), A Review of Literature Related to the Use of Spray Dryer Absorber Material: Production, Characterization, Utilization Applications, Barriers, and Recommendations, December 6, 2006, Table 1–2.

[30] These units are 620 MW pulverized coal fired boilers that burn similar low sulfur PRB coal (0.5–0.7 lb/MMBtu) that were placed into service in 1980 and 1985, respectively. They were retrofitted with wet scrubbers in 2006 and 2007, respectively.

[31] Throughout this document, any reference to "ODEQ modeling" refers to modeling performed or reviewed by ODEQ.

[32] 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*).

BART determination or only SO_2/H_2SO_4 emissions for SO_2 BART determinations. Due to the nonlinear nature and complexity of atmospheric chemistry and chemical transformation among pollutants, CALPUFF modeling on a pollutant-specific basis is not recommended.[33] Furthermore, this approach does not allow for predictions of total visibility impairment for different control scenarios at Class I area receptors and the determination of the 98th percentile day for visibility impairment. In the case of NO_X BART determinations for gas-fired units performed by ODEQ, modeling results from this approach are informative because SO_2 and PM emissions are minimal.

Although we generally regard the visibility modeling analyses performed by ODEQ in support of BART determinations to be of high quality, some deviations from our guidance and errors in emission calculations were noted. We performed our own modeling analysis of the three facilities, incorporating changes to meet our guidance and correct errors in emission calculations. We note that refined CALPUFF modeling included in ODEQ's SIP used updated meteorological fields that included observations in accordance with EPA guidance (40 CFR Part 51, Appendix W) and we utilized this data in our own modeling analysis. In the ODEQ modeling, sulfuric acid emissions from the OG&E units were estimated based on an assumed 1% SO_2 to SO_3 conversion rate across the boiler. A control efficiency of 40% was assumed for the wet scrubbing control scenario and 90% for the dry scrubbing scenario. Emissions from the AEP/PSO units were calculated based on an assumed 3 ppm sulfur content conversion in the flue gas. As detailed in the TSD, we utilized a different approach based on the best current information from the Electric Power Research Institute (EPRI)[34] to estimate the sulfuric acid released from combustion in the boiler. ODEQ's speciation of PM emissions, estimated for use in PM only modeling, contained errors in the parameters used in the calculation of speciation factors. As discussed in the above sections, we concluded that the dry scrubber and the wet scrubber could achieve emission limits of 0.06 lb/MMbtu SO_2 and 0.04 lb/MMbtu SO_2, respectively, and these limits were used to calculate emissions for our visibility modeling. Our emission estimation methodology is detailed in the TSD.

We remodeled the visibility impacts of the OG&E and AEP/PSO units to correct these errors and to provide consistency with modeling guidance we have provided to the states. First, the model was run using the pre-BART conditions to establish a baseline. For all modeling runs, all relevant visibility-impairing pollutants were included. The model was then run to include the control technology selected as NO_X BART, LNB with OFA, in order to evaluate the visibility benefit expected from this control and separate the benefit of installation of NO_X BART from that due to SO_2 control technologies. Modeling results of the visibility impact due to installation of LNB show significant improvement in visibility over the baseline. These results in combination with review of the cost analysis and other factors considered in the ODEQ BART determination support the conclusion that LNB with OFA is NO_X BART for these units. To evaluate the anticipated visibility improvement due to wet and dry scrubbers, these control technologies were modeled for each facility. These modeling control scenarios with scrubbers for SO_2 also included NO_X emissions controlled by LNB with OFA. The modeled visibility impacts were then compared to the impact achieved with only LNB with OFA and no additional controls on SO_2 to evaluate the incremental visibility benefit of each SO_2 control technology (wet or dry scrubber).

The results of our visibility modeling analyses, for the maximum impacts of the 98th percentile delta-dv impacts from 2001–2003 are presented as Table 8. These results employ our revised emission calculations and methodology, and the new IMPROVE equation (Method 8). As can be seen from these results, despite employing an SO_2 emission limit of 0.04 lbs/MMBtu in the wet scrubber case (versus 0.06 lbs/MMBtu in the dry scrubber case), the visibility modeling does not show a consistent, clear benefit for wet scrubbing. A possible explanation for this is that by reducing the SO_2 emissions to the rate of 0.06 lb/MMbtu, the 98th percentile days are primarily winter days when nitrate particulates are responsible for the majority of visibility impairment. Additional controls of SO_2 do not yield a reduction in sulfate large enough to provide significant visibility improvement for the 98th percentile value. In some cases, the further reduction in sulfate on these days results in a small increase in available ammonia for reaction with NO_X and leads to a slight increase in visibility impairment due to additional nitrate particulate that can offset the benefit due to less sulfate particulate.

TABLE 8—EPA MODELED MAXIMUM IMPACTS OF THE 98TH PERCENTILE DELTA-DV IMPACTS FROM 2001–2003

Class I area	Visibility impact (Δ dv)				Improvement over baseline due to LNB	Improvement over LNB due to DFGD	Improvement over LNB due to WFGD
	Baseline	LNB	LNB & DFGD	LNB & WFGD			
Sooner Units 1&2							
Caney Creek	0.73	0.50	0.13	0.13	0.23	0.37	0.38
Hercules-Glades	0.71	0.43	0.13	0.12	0.28	0.30	0.31
Upper Buffalo	0.77	0.49	0.13	0.12	0.28	0.35	0.37
Wichita Mountains	2.08	1.46	0.41	0.35	0.62	1.05	1.11
Total	4.28	2.88	0.80	0.71	1.41	2.08	2.16
Muskogee Units 4&5							
Caney Creek	1.48	1.19	0.45	0.51	0.29	0.74	0.69
Hercules-Glades	1.07	0.92	0.19	0.19	0.14	0.74	0.73

[33] Memo from Joseph Paisie (Geographic Strategies Group, OAQPS) to Kay Prince (Branch Chief EPA Region 4) on Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations, July 19, 2006.

[34] Electric Power Research Institute, Estimating Total Sulfuric Acid Emissions from Stationary Power Plants, 1016384, technical Update, March 2008.

TABLE 8—EPA MODELED MAXIMUM IMPACTS OF THE 98TH PERCENTILE DELTA-DV IMPACTS FROM 2001–2003—Continued

Class I area	Visibility impact (Δ dv)				Improvement over baseline due to LNB	Improvement over LNB due to DFGD	Improvement over LNB due to WFGD
	Baseline	LNB	LNB & DFGD	LNB & WFGD			
Upper Buffalo	1.52	1.20	0.37	0.33	0.31	0.84	0.87
Wichita Mountains	1.31	1.03	0.29	0.34	0.27	0.75	0.70
Total	5.37	4.35	1.29	1.37	1.02	3.06	2.98
Northeastern Units 3&4							
Caney Creek	1.70	0.99	0.29	0.30	0.71	0.70	0.69
Hercules-Glades	0.92	0.88	0.18	0.20	0.04	0.70	0.68
Upper Buffalo	1.52	0.85	0.28	0.28	0.67	0.57	0.57
Wichita Mountains	1.66	1.39	0.30	0.31	0.27	1.09	1.08
Total	5.80	4.11	1.05	1.09	1.69	3.06	3.02

In Table 9, we extract the results of our visibility modeling from Table 8 for the dry scrubbing case, and total the results across the OG&E and AEP/PSO facilities, and across Class I areas. This is again based on the maximum impacts 98th Percentile delta-dv impacts from 2001–2003.

TABLE 9—EPA MODELED MAXIMUM IMPACTS DUE TO DRY SCRUBBING OF THE 98TH PERCENTILE DELTA-DV IMPACTS FROM 2001–2003

Class I area	Improvement over LNB + OFA due to dry scrubbing			
	Sooner	Muskogee	Northeastern	Total Sooner Muskogee Northeastern
Caney Creek	0.37	0.74	0.70	1.81
Hercules-Glades	0.30	0.74	0.70	1.74
Upper Buffalo	0.35	0.84	0.57	1.76
Wichita Mountains	1.05	0.75	1.09	2.89
Total All Class I Areas	2.07	3.07	3.06	8.20

The visibility improvements documented in Table 9 are significant and will result in marked steps toward reaching natural background conditions.

3. Our Conclusion on Oklahoma's SO_2 BART Evaluations for the Six OG&E and AEP/PSO Units

As discussed above, ODEQ concludes that it is too expensive to control the SO_2 emissions from the OG&E and AEP/PSO units in question and that the potential visibility benefits are not substantial enough to justify additional control. As we have shown above, we disagree with ODEQ's conclusion on costs for SO_2 controls and we find that cost effective SO_2 controls are available and our modeling demonstrates that substantial visibility improvement is achievable based on the installation of these controls. In particular, our modeling indicates that dry scrubbing will result in a 2.89 deciview improvement in visibility at the Wichita Mountains. Furthermore, the addition of SO_2 scrubbers (wet or dry) on each of the three facilities (2 units at each facility) will reduce visibility impairment at Class I areas (Wichita Mountains and/or other surrounding Class I areas) from values that are above the 1 deciview impact that is a direct causation of visibility impairment to levels that are below the 0.5 deciview threshold that ODEQ used for determining if a source contributed to visibility impairment. We consider the reduction in visibility impairment at Wichita Mountains, Caney Creek, Upper Buffalo, and Hercules-Glades to be significant both for the RH SIP and also for reduction of visibility impairment on other states in meeting the requirements of the 110 (a)(2)(D) SIP. Therefore, we propose to disapprove Oklahoma's submitted SO_2 BART determinations for the six BART sources in question. Consequently, we propose a FIP to address this deficiency.

4. Alternative BART Determination

The RH submittal includes an alternative to BART for the six BART sources entitled "Greater Reasonable Progress Alternative Determination" (Alternative Determination). This Alternative Determination submittal includes executed agreements between ODEQ and OG&E, and ODEQ and AEP/PSO entitled, "OG&E Regional Haze Agreement, Case No. 10–024, and "PSO Regional Haze Agreement, Case No. 10–025." The submitted Alternative Determination provides for alternative control scenarios that would apply were we to disapprove ODEQ's SO_2 BART determinations for the OG&E and AEP/PSO units. Under the Alternative Determination, following the exhaustion of all administrative and judicial appeals of disapproval by us of the BART determinations for the six units, the BART determination would be superseded by a requirement that the OG&E and AEP/PSO units comply with either of the following requirements:

By January 1, 2018, install dry scrubbers (and fabric filters for PM control at the OG&E units) or otherwise meet SO_2 and PM emission limits specified by ODEQ.[35]

[35] These emission limits are a 30-day rolling average SO_2 emission limit of 0.10 lbs/MMBtu.

By December 31, 2026, meet a combined annual SO_2 emission limit that is equivalent to: (i) the SO_2 emission limits specified by ODEQ on half of the OG&E units and half of the AEP/PSO units; and (ii) being at or below the SO_2 emissions that would result from switching the remaining units to natural gas.

In other words, after having exhausted any rights to challenge our disapproval of ODEQ's BART determinations, OG&E and AEP/PSO could elect to either (1) install dry scrubbers at the beginning of 2018; or (2) scrub half of their units (again at the higher rate) and switch the other half (not specified as to plant for OG&E) to natural gas by the end of 2026. We find that neither of these alternatives would comport with the requirements of section 51.308, as explained below.

Our regulations do provide states with the flexibility to adopt alternatives to BART. Such alternatives, for example, could include fuel switching beyond the five-year window allowed for the installation of BART. Such alternatives, however, must be shown to provide for greater reasonable progress than BART does and must be fully implemented prior to the close of the planning period for the first regional haze SIP. 40 CFR 51.308(e)(2)(i) and (iii).

Even assuming that a contingent SIP provision triggered by the conclusion of all appeals regarding a related provision could be considered enforceable, we do not believe that the Alternative Determination is approvable. We propose to disapprove the Alternative Determination because neither of the set of contingent emission limitations meets the requirements of our RH regulations governing "better than BART" alternatives. As described above, ODEQ concluded that BART requires no additional controls at these units. The Alternative Determination would apply only where we have disagreed with this conclusion, disapproved the SIP, and prevailed in any ensuing litigation. It seems highly probable in such a situation that both the courts and we would have concluded that BART requires the use of scrubbers. Given this, the first potential requirement, that the BART units install scrubbers in January 2018, does not provide for greater reasonable progress than does BART. Rather, it allows OG&E and AEP/PSO to delay the installation of scrubbers beyond the time period allowed by the CAA.[36] In addition to the question of timing, the emission limits associated with the first potential requirement are substantially higher than what we have proposed as BART using the same controls, dry scrubbers. We have not seen any explanation from ODEQ as to how allowing OG&E and AEP/PSO additional time in which to meet less stringent emission limitations provides for greater reasonable progress.

The second potential requirement does not require any reduction in emissions from the BART units until 2026, near the end of the second long-term strategy period for RH. Again, we have seen no explanation of how such an extended compliance period would result in greater reasonable progress. More significantly, however, such an approach is not allowed by our regulations governing alternatives to BART, which require all necessary emission reductions to take place during the period of the first long-term strategy for RH, *i.e.* by 2018. 40 CFR 51.308(e)(2)(iii).

For the reasons discussed here, we propose to disapprove as part of the Oklahoma RH SIP, this submitted "Alternative Determination." If Oklahoma provides us with an alternative demonstration that complies with 40 CFR 51.308(e)(2)(i) and (iii), we will consider it under a future action.

F. Federal Implementation Plan To Address SO_2 BART for the Six Sources

1. Introduction

As discussed above, we propose to disapprove Oklahoma's BART determination for the six sources in question. In addition, as discussed in Section VI, we have determined that additional controls are necessary on these units to prevent emissions from Oklahoma from interfering with other states' plans to improve visibility, and we are partially disapproving the Oklahoma SIP as it pertains to that requirement. To correct the deficiencies identified in these proposed disapprovals, we are also proposing a FIP.

In proposing a FIP to address BART, we must consider the same factors as states. As discussed above, we agree with ODEQ's evaluation for pollutants other than SO_2, but disagree for SO_2 in two respects. First, we believe that dry scrubbing and wet scrubbing are both cost effective. Second, we have identified some concerns with ODEQ's estimation of visibility impacts and accordingly have re-evaluated the visibility impacts of these controls. Our modeling shows that the use of these controls will result in greater improvement in visibility than estimated by ODEQ.

We propose to find that both dry scrubbing and wet scrubbing provide cost effective reductions of SO_2. We also believe that implementation of these controls will provide substantial visibility improvement at four Class I areas.

2. Appropriate Emission Limits

In our BART Guidelines, we established an SO_2 presumptive limit that applies to Electricity Generating Units (EGUs) at power plants with a total generating capacity in excess of 750 MW of either 0.15 lbs/MMBtu, or 95% control. 70 FR 39104, 39131. We required that states, as a general matter, must require owners and operators of greater than 750 MW power plants to meet these BART emission limits. In addition, we noted that the presumption does not limit the states' ability to consider whether a different level of control is appropriate in a particular case. We stated that "[i]f, upon examination of an individual EGU, a state determines that a different emission limit is appropriate based upon its analysis of the five factors, then the state may apply a more or less stringent limit." *Id.* Because we are making the BART determinations under our FIP, we are obligated to determine the appropriate level of control.

a. Dry Scrubber Emission Limit

As is detailed in our TSD, dry scrubber performance varies with the sulfur content of the coal. Our analysis indicates that a dry scrubber on the OG&E units can remove approximately 90% of the SO_2 when burning coal with an uncontrolled emission rate of approximately 0.51 lb/MMBtu, 91.5% when burning coal corresponding to ODEQ's proposed BART limit of 0.65 lb/MMBtu, and 95% when burning the coal used to size the scrubber, 1.18 lb/MMBtu. Similarly, our analysis indicates that a dry scrubber on the Northeastern units can remove approximately 93% of the SO_2 when burning coal with an uncontrolled emission rate of 0.9 lb/MMBtu, and 91.5% when burning coal corresponding to ODEQ's proposed BART limit of 0.65 lb/MMBtu. This information is summarized in Table 10:

TABLE 10—EXPECTED DRY SCRUBBER PERFORMANCE VS. UNCONTROLLED EMISSION RATES

Control (percent)	Uncontrolled emission rate (lbs/MMBtu)	Controlled emission rate (lbs/MMBtu)
90.0	0.51	0.051
91.5	0.65	0.055
93.0	0.90	0.063
95.0	1.18	0.059

[36] BART must be installed and operational as expeditiously as practicable, but in no event later than five years after approval of an implementation plan. CAA 169A(g)(4).

Based on this information, our analysis indicates that an SO_2 emission limit of 0.06 lbs/MMBtu can be met on the basis of a 30-day rolling average for the OG&E and AEP/PSO units, using dry scrubber technologies. As is noted in our TSD, there are already facilities operating below this emission rate, using dry scrubber technologies, and that burn similar coals.

b. Wet Scrubber Emission Limit

According to OG&E's contractor, "[w]et scrubbing is the predominant technology for large-scale utility applications in most parts of the world." In addition, "SO_2 removal guarantees of up to 99% (without additives) are available from the system suppliers and have been demonstrated in commercial applications, though there is a practical outlet limitation at 0.04 lb. SO_2/MBtu, which represents a lower percentage removal for the lowest sulfur coals." [37] However, as we note in our TSD, Pleasant Prairie Units 1 and 2, similar boilers that burn a similar low sulfur PRB coal, were retrofitted with wet scrubbers in 2006 and 2007. An examination of our Clean Air Markets Division SO_2 emissions data for Unit 1 for the period 2007 through June 2010 indicates this unit easily meets a 365-day rolling average of less than 0.03 lb/MMBtu. Similarly, the Minnesota Power Boswell 3 unit was recently retrofit with a wet scrubber (among other pollution control upgrades) and, based on our Clean Air Markets Division SO_2 emissions data, it appears to be achieving a monthly average emission rate of less than 0.03 lbs/MMBtu. This, along with other similar examples discussed in our TSD, indicates that wet scrubbing at the OG&E and AEP/PSO units could consistently result in an SO_2 removal efficiency of 98%, or meet an emission limit of 0.04 lbs/MMBtu on a 30-day rolling average.

3. Visibility Benefit From Dry and Wet Scrubbing

As discussed in our evaluation of ODEQ's BART evaluation, our modeling indicates substantial visibility benefit from the implementation of dry scrubbing. We did not find substantial additional visibility benefits on the 98th percentile value from the use of wet scrubbers even though we believe wet scrubbers would be expected to achieve lower emissions. As a result, we propose that the emission limit in the FIP be based on the emission levels that can be achieved by dry scrubbing.

4. EPA's SO_2 BART Determination for the Six Units

As described above, for the particular cases we are considering in this action, we have concluded there is a lack of a clear visibility advantage to wet scrubbing at the SO_2 emission rates we have considered. Other details concerning the input values we have assumed in our visibility modeling are contained in the TSD. We invite comment on all aspects of our visibility modeling. Given that wet scrubbing is approximately 9% higher in cost on a $/tons of SO_2 removed basis, we propose that SO_2 BART for the Units 4 and 5 of the OG&E Muskogee plant, Units 1 and 2 of the OG&E Sooner plant, and Units 3 and 4 of the AEP/PSO Northeastern plant should be based on dry scrubbing. We note there are significant advantages to wet scrubbing that OG&E and/or AEP/PSO may find attractive as a means of satisfying our proposed FIP.

As we note above, under section 51.308(e)(1)(iv), "each source subject to BART [is] required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision." Based on the retrofit of other scrubber installations we have reviewed, we find that three (3) years from the date our final determination becomes effective is adequate time for the installation and operation of these controls.[38] We solicit comments on alternative timeframes, of from two (2) years up to five (5) years from the effective date our final rule.

We do not wish to dissuade companies from exercising the option of switching to natural gas as a means of satisfying their BART obligations under section 51.308(e). Such an approach, for example, would be acceptable for satisfying SO_2 BART,[39] if it satisfies the requirement under section 51.308(e)(1)(iv) that, "each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision." Switching to natural gas would be an acceptable method of complying with the limits proposed in this FIP. In addition, we invite comments as to, considering the engineering and/or management challenges of such a fuel switch, whether the full 5 years allowed under section 308(e)(1)(iv) following our final action would be justified.

G. 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. Oklahoma's 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 Oklahoma LTS was developed by ODEQ, 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 Inventory

Section 51.308(d)(3)(iii) requires that Oklahoma 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. Oklahoma must identify the baseline emissions inventory on which its strategies are based. Section 51.308(d)(3)(iv) requires that Oklahoma 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. Oklahoma 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 Oklahoma. The 2018 emissions

[37] Sargent & Lundy, Flue Gas Desulfurization Technology, Dry Lime vs. Wet Limestone FGD, Prepared for National Lime Association, March 2007.

[38] Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies, EPA–600/R–02/073, October 2002, pdf pagination 5: "Conservatively high assumptions were made for the time, labor, reagents, and steel needed to install FGD systems. For LSFO installation timing, it is expected that one system requires about 27 months of total effort for planning, engineering, installation, and startup, with connections occurring during normally scheduled outages)," *available* at *http://www.epa.gov/clearskies/pdfs/multi102902.pdf.*

[39] We note that, as with the other fossil fuel fired power plant BART determinations contained within this proposal, separate NOx and PM BART determinations must also be made.

inventory was 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. Oklahoma's 2002 Emission Inventory

ODEQ 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. Oklahoma's 2002 emissions inventory is summarized in Table 11:

TABLE 11—OKLAHOMA'S 2002 EMISSIONS INVENTORY

	SO_2	NH_3	NO_X	VOCs	PM_{10}–$PM_{2.5}$	$PM_{2.5}$
Point	148,761	24,102	158,818	37,794	8,026	8,636
Area	11,779	114,363	115,407	201,758	304,560	109,279
Non-road mobile	4,773	280	49,396	47,863	433	4,580
On-road mobile	4,708	4,434	142,592	99,924	879	2,459
Biogenic	0	0	35,909	988,314	0	0
Total	170,021	143,179	502,122	1,375,653	313,898	124,954

See the TSD for details on how the 2002 emissions inventory was constructed. We propose that Oklahoma's 2002 emission inventory is acceptable.

b. Oklahoma's 2018 Emission Inventory

In general, ODEQ used a combination of our Economic Growth Analysis System (EGAS 5), our mobile emissions factor model (MOBILE 6), our off-road emissions factor model (NONROAD), and the Integrated Planning Model (IPM) for electric generating units in constructing its 2018 emission inventory. ODEQ modified the projected emissions from the IPM modeling for OG&E Sooner and Muskogee electric power plants and the PSO Northeast electric power plants to reflect the application of presumptive BART controls.[40] More specifically, CENRAP developed emissions for five inventory source classifications: point, area, non-road and on-road mobile sources, and biogenic sources. CENRAP used its 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. Oklahoma's 2018 emissions inventory is summarized in Table 12:

TABLE 12—OKLAHOMA'S 2018 EMISSIONS INVENTORY

	SO_2	NH_3	NO_X	VOCs	PM_{10}–$PM_{2.5}$	$PM_{2.5}$
Point	106,701	35,215	140,298	125,648	8,935	13,989
Area	12,374	141,532	128,257	400,056	275,844	127,018
Non-road mobile	156	40	25,387	28,489	2,914	292
On-road mobile	545	5,818	39,397	39,281	0	953
Biogenic	0	0	35,909	988,314	0	0
Total	119,776	182,605	369,248	1,581,788	287,693	142,252

See the TSD for details on how the 2018 emissions inventory was constructed. CENRAP and ODEQ used this and other state's 2018 emission inventories to construct visibility projection modeling for 2018. We propose that Oklahoma's 2018 emission inventory is acceptable but for its inclusion of reductions from the OG&E and AEP/PSO coal fired units that were not ultimately required by Oklahoma. As discussed above, we propose a FIP to address this deficiency.

2. Visibility Projection Modeling

CENRAP performed modeling for the RH LTS for its member states, including Oklahoma. 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.[41]

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

[40] Note, our proposed FIP, discussed in section V.E, would require a stricter level of SO_2 for six units in these facilities.

[41] Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, 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.

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 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. Table 13, derived from Table VIII–9 of the Oklahoma RH SIP submittal, summarizes the projected contribution from Oklahoma emissions on visibility degradation at Class I areas for the 20 percent worst days in 2018. Note, this table only includes contributions of 0.15 deciviews or greater.

TABLE 13—PROJECTED CONTRIBUTION FROM OKLAHOMA EMISSIONS ON VISIBILITY DEGRADATION FOR THE 20 PERCENT WORST DAYS IN 2018

Class I area	State	Contribution to light extinction (Mm-1)	Total light extinction (Mm-1)	Oklahoma contribution (percent)	Deciview contribution
Wichita Mountains	Oklahoma	12.28	86.56	14.19	1.53
Hercules-Glades	Missouri	3.74	103.49	3.61	0.37
Salt Creek	New Mexico	1.46	57.67	2.53	0.26
Caney Creek	Arkansas	2.23	96.84	2.30	0.23
Upper Buffalo	Arkansas	1.97	97.16	2.03	0.21
Guadalupe Mountains	Texas	1.11	55.43	2.00	0.20
Seney	Michigan	1.74	95.27	1.83	0.18
White Mountain	New Mexico	0.69	40.8	1.70	0.17
Isle Royale	Michigan	1.08	73.71	1.46	0.15

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

As in the development of Oklahoma's reasonable progress goal for the Wichita Mountains, ODEQ used CENRAP as its main vehicle for facilitating collaboration with FLMs and other states in satisfying its LTS consultation requirement. This helped ODEQ 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 Oklahoma 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 Oklahoma consult with other states if their emissions are reasonably anticipated to contribute to visibility impairment at the Wichita Mountains. ODEQ's consultations with other states are described in section V.C.3 above. After evaluating whether emissions from Oklahoma sources contribute to visibility impairment in other states' Class I areas, ODEQ concluded there was no contribution sufficient to require consultation. ODEQ's evaluation relied, however, upon SO_2 BART reductions from the six units of the OG&E and AEP/PSO three coal fired power plants but these reductions are not required. Regardless of its conclusions regarding the impacts of Oklahoma emissions on other states' Class I areas, however, Oklahoma did consult with other states and tribes, largely through the CENRAP process. We propose that those consultations adequately satisfy the requirement under Section 51.308(d)(3)(i).

Section 51.308(d)(3)(ii) requires that if Oklahoma emissions cause or contribute to impairment in another state's Class I area, Oklahoma must demonstrate that it has included in its RH SIP all measures necessary to obtain its share of the emission reductions needed to meet the progress goal for that Class I area. Section 51.308(d)(3)(ii) also requires that since Oklahoma participated in a regional planning process, it must ensure it has included all measures needed to achieve its apportionment of emission reduction obligations agreed upon through that process. As we state in the RHR[42], Oklahoma's commitments to participate in CENRAP bind it to secure emission reductions agreed to as a result of that process, unless it proposes a separate process and performs its consultations on the basis of that process:

While States are not bound by the results of a regional planning effort, nor can the content of their SIPs be dictated by a regional planning body, we expect that a coordinated regional effort will likely produce results the States will find beneficial in developing their regional haze implementation plans. Any State choosing not to follow the recommendations of a regional body would need to provide a specific technical basis that its strategy nonetheless provides for reasonable progress based on the statutory factors. At the same time, EPA cannot require States to participate in regional planning efforts if the State prefers to develop a long-term strategy on its own. We note that any State that acts alone in this regard must conduct the necessary technical support to justify their apportionment, which generally will require regional inventories and a regional modeling analysis. Additionally, any such State must consult with other States before submitting its long-term strategy to EPA.

Consequently, because Oklahoma accepted and incorporated the CENRAP-developed visibility modeling into its RH SIP, which assumed controls for the six units discussed above that were not subsequently secured, we propose to disapprove Oklahoma's long term strategy.

However, our proposed FIP does include controls for the six units that at least achieve the level of control assumed in the CENRAP modeling. In addition, as described above, Oklahoma has required controls on additional sources as part of its BART evaluation. Therefore, we propose to find that with the addition of our proposed FIP, the requirements in section 51.308(d)(3)(ii) have been met.

4. Mandatory Long Term Strategy Factors

Section 51.308(d)(3)(v) requires that Oklahoma minimally consider certain

[42] 64 FR 35735.

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 propose to find that Oklahoma has satisfied all the requirements of Section 51.308(d)(3)(v).

In addition to its BART determinations and by extension our proposed FIP, Oklahoma's LTS incorporates emission reductions due to a number of ongoing air pollution control programs. This includes the issuance and enforcement of permits limiting emissions (based on our National Ambient Air Quality Standards) from all major sources in Oklahoma (the SIP also includes permits for minor sources), state rules which specifically limit targeted emissions sources and categories, and other air pollution control programs that ODEQ administers. We note that fine and coarse particulate, of which construction-related activities are thought to be a small contributor, are themselves minor contributors to visibility impairment at the Wichita Mountains. ODEQ relies on fugitive dust control rules to control and minimize dust from construction activities. ODEQ has adopted rules to ensure the enforceability of these emission limitations. This includes rules that govern ODEQ's permitting process for major and minor sources, Prevention of Significant Deterioration (PSD) provisions, Best Available Control Technology (BACT), and BART requirements. These rules have corresponding compliance schedules and enforcement protocols and are summarized in the TSD.

ODEQ issues permits to all major and minor point sources in Oklahoma, and each permit contains enforceable limitations on emissions of various pollutants, including those which cause or contribute to RH at the Wichita Mountains. Unless those permits specify a different schedule for compliance, ODEQ requires permitted sources to comply with their permits immediately upon issuance. ODEQ also enforces compliance schedules of relevant administrative and judicial orders, including consent decrees that result in significant SO_2 and NO_X reductions.

We approved ODEQ's SIP to address reasonably attributable visibility impairment at the Wichita Mountains on November 8, 1999. *See* 64 FR 60683. As we note in section V.H, the FLMs did not identify any integral vistas in Oklahoma. In addition, the Wichita Mountains is not experiencing RAVI, nor are any Oklahoma sources affected by the RAVI provisions. Therefore, the Oklahoma RH SIP does not incorporate any measures to specifically address RAVI.

ODEQ considered source retirement and replacement schedules in developing its long-term strategy of emissions reductions. ODEQ stated it cannot reliably predict the retirement or replacement of sources and consequently does not rely on source retirement to achieve any reasonable progress goal.

Fires are responsible for much of the directly emitted fine particulate matter in the Oklahoma emissions inventory. ODEQ considered smoke management techniques for the purposes of agricultural and forestry management in its LTS. As Tables IV–1 and IV–2 in the Oklahoma RH SIP revision submittal indicate, all types of fire sources (wildfire, agricultural burning, rangeland burning, etc.) are responsible for approximately 4.2% of the total SO_2, 4.1% of the total NH_3, 3.9% of the total NO_X, 2.1% of the total VOCs, and 3.6% of the total PM10 emissions. In contrast, fire is responsible for about 33.4% of the total $PM_{2.5}$ emissions. However, Table VIII–3 of the Oklahoma RH SIP indicates that all Oklahoma area sources combined, of which fire is only a part, account for less than 1% of the total visibility impact at the Wichita Mountains. Nevertheless, ODEQ states that it and the Oklahoma Department of Agriculture, Food, and Forestry intend to create a basic, voluntary smoke management program based on our Interim Air Quality Policy on Wildland and Prescribed Fires. We commend this effort and offer our assistance in the development of this plan.

Section 51.308(d)(3)(v)(F) requires that Oklahoma ensure the enforceability of emission limitations and control measures used to meet reasonable progress goals. ODEQ has issued enforceable Title V operating permits requiring BART-eligible sources subject to BART to install BART and achieve the associated BART emission limits. Similarly, any BART requirement in a FIP must be included by ODEQ in a Part 70 air quality permit. See 70 FR at 39172.

ODEQ has demonstrated it has the statutory authority to regulate air emissions from all facilities and sources subject to operating permit requirements under Title V of the CAA. ODEQ also has the authority to administratively and judicially enforce any provision of an ODEQ issued air quality permits. See the TSD for more details on Oklahoma laws that provide for this authority.

H. 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 Oklahoma. In addition, the Wichita Mountains is not experiencing RAVI, nor are any Oklahoma sources affected by the RAVI provisions. Thus, the Oklahoma RH SIP submittal does not explicitly address the two requirements regarding coordination of RH with the RAVI LTS and monitoring provisions. However, Oklahoma previously made a commitment to address RAVI should the FLM certify visibility impairment from an individual source.[43] We propose to find that this RH submittal appropriately supplements and augments Oklahoma's RAVI visibility provisions to address RH by updating the monitoring and LTS provisions as summarized below in this section.

I. 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

[43] Oklahoma's Part 1 and Part II visibility SIP contained RAVI provisions and was previously approved by EPA (64 FR 60683).

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 monitor at the Wichita Mountains is an IMPROVE monitor, we propose that ODEQ 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. Shortly after the creation of CENRAP, its monitoring workgroup noted the lack of a representative monitor for the Wichita Mountains. At that time, an IMPROVE site for Upper Buffalo, Arkansas, in a wetter climate several hundred miles to the east-northeast, provided the closest available visibility monitoring data. Because this monitoring data was deemed unrepresentative, a particle sampler monitor was established at the Wichita Mountains and began operating in March, 2001. As described in section V.B., above, baseline visibility conditions were calculated using data representative of 2002–2004 due to lack of data from previous years. With the addition of the monitor at the Wichita Mountains, we propose to find that ODEQ has satisfied this requirement.

Section 51.308(d)(4)(ii) requires that ODEQ establish procedures by which monitoring data and other information are used in determining the contribution of emissions from within Oklahoma to RH visibility impairment at mandatory Class I Federal areas both within and outside the state. The monitor at the Wichita Mountains is operated by Wichita Mountains 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 therefore propose that ODEQ 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, Oklahoma should report visibility monitoring data electronically. Section 51.308(d)(4)(vi) also requires that ODEQ provide for other elements, including reporting, recordkeeping, and other measures, necessary to assess and report on visibility. We propose that Oklahoma's 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)(iv) requires that ODEQ 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 ODEQ's emission inventory. ODEQ has stated that it intends to update the Oklahoma statewide emissions inventories periodically and review periodic emissions information from other states and future emissions projections. We propose that this satisfies the requirement.

J. Federal Land Manager Coordination

The Wichita Mountains is one of more than 546 refuges throughout the United States managed by the Fish and Wildlife Service, which is the Federal Land Manager (FLM) for this Class I area. Although the FLMs are very active in participating in the RPOs, the RH Rule grants the FLMs a special role in the review of the RH SIPs, summarized in section IV.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, Oklahoma must have identified in writing to the FLMs the title of the official to which the FLM of the Wichita Mountains 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), Oklahoma was obligated to provide the Fish and Wildlife 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. ODEQ followed this practice and sent its draft of this implementation plan revision to the federal land manager staff on October 1, 2009 and notified the federal land manager staff of the public hearing held on December 16, 2009. In its letter dated December 4, 2009, transmitting its comments, the Fish and Wildlife Service acknowledged having received Oklahoma's draft RH SIP on October 5, 2009.

The FLMs have communicated to us their dissatisfaction with the fact that the draft RH SIP they were provided by ODEQ was markedly different than the version ODEQ submitted to us as their final RH SIP. Specifically, the FLMs note that in the version of the SIP they reviewed, SO_2 BART for the six OG&E and AEP/PSO coal fired units that are the subject of our FIP was determined by ODEQ to be dry SO_2 scrubbers with an emission limit of 0.10 lbs/MMBtu for the OG&E units, and 0.153 lbs/MMBtu for the AEP–PSO units. When ODEQ submitted their final RH SIP to us, those SO_2 BART determinations were changed to replace the SO_2 scrubber requirements with an SO_2 limit of 0.65 lbs/MMBtu on a 30 day rolling average that corresponds to uncontrolled low sulfur coal. We note the Fish and Wildlife Service has not requested that ODEQ re-open their 60 day comment period. We would like to address any question as to whether section 51.308(i)(2) has been satisfied. We believe, however, that our proposed FIP, as described in section V.F., above, may alleviate these concerns. We invite the FLMs to provide comment on this or other aspects of our proposal.

Section 51.308(i)(3) requires that ODEQ provide in its RH SIP a description of how it addressed any comments provided by the FLMs. ODEQ has provided that information in Appendix 10–2 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. ODEQ has stipulated in its RH SIP it will continue to coordinate and consult with the FLMs as required by section 51.308(i)(4). ODEQ states it intends to consult the FLMs in the development and review of implementation plan revisions; review of progress reports; and development and implementation of other programs that may contribute to impairment of visibility at the Wichita Mountains and other Class I areas. We propose that ODEQ has satisfied section 51.308(i).

K. Periodic SIP Revisions and Five-Year Progress Reports

ODEQ affirmed its commitment to complete items required in the future under our RHR. ODEQ 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.

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

If another state's RH SIP identifies that Oklahoma's SIP needs to be supplemented or modified, and if, after appropriate consultation Oklahoma agrees, today's action may be revisited, or the additional information and/or changes will be addressed in the five-year progress report SIP revision.

VI. Our Analysis of Oklahoma's Interstate Visibility Transport SIP Provisions

We received a SIP from Oklahoma 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 May 10, 2007, as supplemented on December 10, 2007. 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, Oklahoma stated that it was on track for the submission of its RH SIP by the December, 17, 2007 deadline.[44] Oklahoma states in its May 10, 2007 submittal that it intended that its RH SIP be used to satisfy the requirements of section 110(a)(2)(D)(i)(II) that emissions from Oklahoma sources do not interfere with measures required in the SIP of any other state under part C of the CAA to protect visibility. However, it did not establish that emissions from its sources would not interfere with the visibility programs of other states, nor did it as part of its February 19, 2010 RH SIP submittal. In order to evaluate whether Oklahoma's existing SIP adequately prevents interference with the visibility programs of other states, we propose to address this question using other available information.

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 Oklahoma. As we discuss above in section V.G, this modeling assumed SO_2 reductions from the six OG&E and AEP/PSO coal fired units that are the subject of our FIP. Although we have not yet received all RH SIPs, we understand that the CENRAP states used the visibility projection modeling to establish their own respective reasonable progress goals. Thus, we believe that an implementation plan that provides for emissions reductions consistent with the assumptions used in those states' modeling will ensure that emissions from Oklahoma sources do not interfere with the measures designed to protect visibility in other states.

However, after the visibility projection modeling and all consultations were completed, Oklahoma revised its SO_2 BART determinations for these six units, as submitted in the RH SIP submittal of February 19, 2010, removing the requirement that they be controlled to ensure these agreed upon emissions limits would be met. Consistent with our proposed conclusion that Oklahoma has not obtained its needed share of emission reductions, as we discuss above in section V.G.3, we propose to find that the Oklahoma SIP revision submittals do not ensure that emissions from sources in Oklahoma do not interfere with other State's visibility programs as required by section 110(a)(2)(D)(i)(II) of the CAA.

Our proposed FIP does include controls for the six units that at least achieve the level of control assumed in the CENRAP modeling. In addition, as described in section V.D., above, Oklahoma has required controls on sources as part of its BART evaluation. Thus, we believe that the controls proposed under our FIP, plus the additional controls required by Oklahoma under its SIP that we propose to approve, constitute the assemblage of cost effective controls that are reasonable at this time, and serve to prevent sources in Oklahoma from emitting pollutants in amounts that will interfere with efforts to protect visibility in other states. In light of this, we propose to partially approve and partially disapprove the Oklahoma SIP revision submitted to address the requirements of section 110(a)(2)(D)(i)(II) of the CAA.

VII. Proposed Actions

A. Regional Haze

We propose to partially approve and partially disapprove Oklahoma's RH SIP revision submitted on February 19, 2010. Specifically, we propose to disapprove the SO_2 BART determinations for Units 4 and 5 of the Oklahoma Gas and Electric Muskogee plant; Units 1 and 2 of the Oklahoma Gas and Electric Sooner plant; and Units 3 and 4 of the American Electric Power/Public Service Company of Oklahoma Northeastern plant. We propose to disapprove these SO_2 BART determinations because they do not comply with our regulations under 40 CFR 51.308(e). We are also proposing to disapprove Oklahoma's long term strategy under section 51.308(d)(3) because it does not incorporate these emission reductions. ODEQ participated in the CENRAP visibility modeling development that assumed certain SO_2 reductions from these six BART units. ODEQ also performed its consultations with other states with the understanding that these reductions would be secured. We propose a FIP to cure these defects in BART and the LTS.

We propose to find that Units 4 and 5 of the OG&E Muskogee plant, Units 1 and 2 of the OG&E Sooner plant, and Units 3 and 4 of the AEP/PSO

[44] *See* 40 CFR 51.308(b).

Northeastern plant are subject to BART under 40 CFR 51.308(e). Further, we propose a FIP that specifically imposes SO_2 BART on these six sources. We propose that SO_2 BART for Units 4 and 5 of the OG&E Muskogee plant, Units 1 and 2 of the OG&E Sooner plant, and Units 3 and 4 of the AEP/PSO Northeastern plant is an SO_2 emission limit of 0.06 lbs/MMBtu that applies singly to each of these units on a 30 day rolling average. Additionally, we propose monitoring, record-keeping, and reporting requirements to ensure compliance with these emission limitations.

We propose that compliance with the emission limits be within three (3) years of the effective date of our final rule. We solicit comments on alternative timeframes, of from two (2) years up to five (5) years from the effective date of our final rule.

Should OG&E and/or AEP/PSO elect to reconfigure the above units to burn natural gas, as a means of satisfying their BART obligations under section 51.308(e), that conversion should be completed by the same time frame. We invite comments as to, considering the engineering and/or management challenges of such a fuel switch, whether the full 5 years allowed under section 308(e)(1)(iv) following the effective date of our final rule would be appropriate.

We propose to disapprove section VI.E of the Oklahoma RH SIP entitled, "Greater Reasonable Progress Alternative Determination." We also propose to disapprove the separate executed agreements between ODEQ and OG&E, and ODEQ and AEP/PSO entitled "OG&E Regional Haze Agreement, Case No. 10–024," and "PSO Regional Haze Agreement, Case No. 10–025," housed within Appendix 6–5 of the RH SIP. We propose that these portions of the submittal are severable from the BART determinations and the LTS; therefore, no FIP is required.

We are taking no action on whether Oklahoma has satisfied the reasonable progress requirements of section 51.308(d)(1).

We propose to approve all other portions of the Oklahoma RH SIP. We note that all controls required as part of Oklahoma's BART determinations, not included as part of our proposed FIP, must be operational within five years from the effective date of our final rule.

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 Oklahoma 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 propose a partial approval and partial disapproval of the Oklahoma Interstate Transport SIP provisions that address the requirement of section 110(a)(2)(D)(i)(II) that emissions from Oklahoma sources do not interfere with measures required in the SIP of any other state under part C of the CAA to protect visibility. With regard to whether emissions from Oklahoma sources interfere with the visibility programs of other states, we are proposing to find that Oklahoma sources, except for Units 4 and 5 of the OG&E Muskogee plant, Units 1 and 2 of the OG&E Sooner plant, and Units 3 and 4 of the AEP/PSO Northeastern plant, are sufficiently controlled to eliminate interference with the visibility programs of other states, and for the six units we are proposing specific SO_2 emission limits that will eliminate such interstate interference.

VIII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

This proposed action is not a "significant regulatory action" under the terms of Executive Order (EO) 12866 (58 FR 51735, October 4, 1993), and is therefore not subject to review under the Executive Order. The proposed FIP applies to only three facilities and is not a rule of general applicability.

B. Paperwork Reduction Act

This proposed action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* Under the Paperwork Reduction Act, a "collection of information" is defined as a requirement for "answers to * * * identical reporting or recordkeeping requirements imposed on ten or more persons * * *." 44 U.S.C. 3502(3)(A). Because the proposed FIP applies to just three facilities, the Paperwork Reduction Act does not apply. *See* 5 CFR 1320(c).

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid Office of Management and Budget (OMB) control number. The OMB control numbers for our regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's proposed rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this proposed action on small entities, I certify that this proposed action will not have a significant economic impact on a substantial number of small entities. The FIP for the three Oklahoma facilities being proposed today does not impose any new requirements on small entities. The proposed partial approval of the SIP, if finalized, merely approves state law as meeting Federal requirements and imposes no additional requirements beyond those imposed by state law. *See Mid-Tex Electric Cooperative, Inc.* v. *FERC*, 773 F.2d 327 (D.C. Cir. 1985)

D. Unfunded Mandates Reform Act (UMRA)

Under sections 202 of the Unfunded Mandates Reform Act of 1995 ("Unfunded Mandates Act"), signed into law on March 22, 1995, EPA must prepare a budgetary impact statement to accompany any proposed or final rule that includes a Federal mandate that may result in estimated costs to State, local, or tribal governments in the aggregate; or to the private sector, of $100 million or more (adjusted to inflation). Under section 205, EPA must select the most cost-effective and least burdensome alternative that achieves the objectives of the rule and is consistent with statutory requirements. Section 203 requires EPA to establish a plan for informing and advising any small governments that may be significantly or uniquely impacted by the rule.

EPA has determined that the approval action proposed does not include a Federal mandate that may result in estimated costs of $100 million or more to either State, local, or tribal governments in the aggregate, or to the private sector. This Federal action proposes to approve pre-existing requirements under State or local law, and imposes no new requirements. Accordingly, no additional costs to State, local, or tribal governments, or to the private sector, result from this action.

E. Executive Order 13132: Federalism

Federalism (64 FR 43255, August 10, 1999) revokes and replaces Executive Orders 12612 (Federalism) and 12875 (Enhancing the Intergovernmental Partnership). Executive Order 13132 requires EPA to develop an accountable process to ensure "meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications." "Policies that have federalism implications" is defined in the Executive Order to include regulations that have "substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government." Under Executive Order 13132, EPA may not issue a regulation that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, or EPA consults with State and local officials early in the process of developing the proposed regulation. EPA also may not issue a regulation that has federalism implications and that preempts State law unless the Agency consults with State and local officials early in the process of developing the proposed regulation.

This rule will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132, because it merely addresses the State not fully meeting its obligation to prohibit emissions from interfering with other states measures to protect visibility established in the CAA. Thus, Executive Order 13132 does not apply to this action. In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on this proposed rule from State and local officials.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Executive Order 13175, entitled *Consultation and Coordination with Indian Tribal Governments* (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications." This proposed rule does not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments. Thus, Executive Order 13175 does not apply to this rule. EPA specifically solicits additional comment on this proposed rule from tribal officials.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

Executive Order 13045: *Protection of Children from Environmental Health Risks and Safety Risks* (62 FR 19885, April 23, 1997), applies to any rule that: (1) is determined to be economically significant as defined under Executive Order 12866; and (2) concerns an environmental health or safety risk that we have reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency. However, to the extent this proposed rule will limit emissions of SO_2, the rule will have a beneficial effect on children's health by reducing air pollution.

This rule is not subject to Executive Order 13045 because it does not involve decisions intended to mitigate environmental health or safety risks. However, to the extent this proposed rule will limit emissions of SO_2, the rule will have a beneficial effect on children's health by reducing air pollution.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12 of the National Technology Transfer and Advancement Act (NTTAA) of 1995 requires Federal agencies to evaluate existing technical standards when developing a new regulation. To comply with NTTAA, EPA must consider and use "voluntary consensus standards" (VCS) if available and applicable when developing programs and policies unless doing so would be inconsistent with applicable law or otherwise impractical.

The EPA believes that VCS are inapplicable to this action. Today's action does not require the public to perform activities conducive to the use of VCS.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994), establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

We have determined that this proposed rule, if finalized, will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. This proposed rule limits emissions of SO_2 from three facilities in Oklahoma. The partial approval of the SIP, if finalized, merely approves state law as meeting Federal requirements and imposes no additional requirements beyond those imposed by state 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.

Dated: March 4, 2011.

Al Armendariz,

Regional Administrator, Region 6.

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

PART 52—[AMENDED]

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

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

2. Part 52 is proposed to be amended by adding § 52.1923 to read as follows:

§ 52.1923 Interstate pollutant transport provisions; What are the FIP requirements for Units 4 and 5 of the Oklahoma Gas and Electric Muskogee plant; Units 1 and 2 of the Oklahoma Gas and Electric Sooner plant; and Units 3 and 4 of the American Electric Power/Public Service Company of Oklahoma Northeastern plant affecting visibility?

(a) *Applicability.* The provisions of this section shall apply to each owner or operator, or successive owners or operators, of the coal burning equipment designated as: Units 4 or 5 of the Oklahoma Gas and Electric Muskogee plant; Units 1 or 2 of the Oklahoma Gas and Electric Sooner plant; and Units 3 or 4 of the American Electric Power/Public Service Company of Oklahoma Northeastern plant.

(b) *Compliance Dates.* Compliance with the requirements of this section is required within 3 years of the effective date of this rule unless otherwise indicated by compliance dates contained in specific provisions.

(c) *Definitions.* All terms used in this part but not defined herein shall have the meaning given them in the Clean Air Act and in parts 51 and 60 of this title. For the purposes of this section:

24-hour period means the period of time between 12:01 a.m. and 12 midnight. *Air pollution control equipment* includes selective catalytic control units, baghouses, particulate or gaseous scrubbers, and any other apparatus utilized to control emissions of regulated air contaminants which would be emitted to the atmosphere.

Daily average means the arithmetic average of the hourly values measured in a 24-hour period.

Heat input means heat derived from combustion of fuel in a unit and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources. Heat input shall be calculated in accordance with 40 CFR part 75.

Owner or Operator means any person who owns, leases, operates, controls, or supervises any of the coal burning equipment designated as:

(i) Unit 4 of the Oklahoma Gas and Electric Muskogee plant; or

(ii) Unit 5 of the Oklahoma Gas and Electric Muskogee plant; or

(ii) Unit 1 of the Oklahoma Gas and Electric Sooner plant; or

(iv) Unit 2 of the Oklahoma Gas and Electric Sooner plant; or

(v) Unit 3 of the American Electric Power/Public Service Company of Oklahoma Northeastern plant; or

(vi) Unit 4 of the American Electric Power/Public Service Company of Oklahoma Northeastern plant.

Regional Administrator means the Regional Administrator of EPA Region 6 or his/her authorized representative.

Unit means one of the coal fired boilers covered under paragraph (a) of this section.

(d) *Emissions Limitations.* SO_2 *emission limit.* The individual sulfur dioxide emission limit for a unit shall be 0.06 pounds per million British thermal units (lb/MMBtu) as averaged over a rolling 30 calendar day period. For each unit, SO_2 emissions for each calendar day shall be determined by summing the hourly emissions measured in pounds of SO_2. For each unit, heat input for each calendar day shall be determined by adding together all hourly heat inputs, in millions of BTU. Each day the thirty-day rolling average for a unit shall be determined by adding together the pounds of SO_2 from that day and the preceding 29 days and dividing the total pounds of SO_2 by the sum of the heat input during the same 30-day period. The result shall be the 30-day rolling average in terms of lb/MMBtu emissions of SO_2. If a valid SO_2 pounds per hour or heat input is not available for any hour for a unit, that heat input and SO_2 pounds per hour shall not be used in the calculation of the 30-day rolling average for SO_2.

(e) *Testing and monitoring.* (1) No later than the compliance date of this regulation, the owner or operator shall install, calibrate, maintain and operate Continuous Emissions Monitoring Systems (CEMS) for SO_2 on Units 4 and 5 of the Oklahoma Gas and Electric Muskogee plant; Units 1 and 2 of the Oklahoma Gas and Electric Sooner plant; and Units 3 and 4 of the American Electric Power/Public Service Company of Oklahoma Northeastern plant in accordance with 40 CFR 60.8 and 60.13(e), (f), and (h), and Appendix B of Part 60. The owner or operator shall comply with the quality assurance procedures for CEMS found in 40 CFR part 75. Compliance with the emission limits for SO_2 shall be determined by using data from a CEMS.

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

(f) *Reporting and Recordkeeping Requirements.* Unless otherwise stated all requests, reports, submittals, notifications, and other communications to the Regional Administrator required by this section shall be submitted, unless instructed otherwise, to the Director, Multimedia Planning and Permitting Division, U.S. Environmental Protection Agency, Region 6, to the attention of Mail Code: 6PD, at 1445 Ross Avenue, Suite 1200, Dallas, Texas 75202–2733. For each unit subject to the emissions limitation in this section and upon completion of the installation of

CEMS as required in this section, the owner or operator shall comply with the following requirements:

(1) For each emissions limit in this section, comply with the notification, reporting, and recordkeeping requirements for CEMS compliance monitoring in 40 CFR 60.7(c) and (d).

(2) For each day, provide the total SO_2 emitted that day by each emission unit. For any hours on any unit where data for hourly pounds or heat input is missing, identify the unit number and monitoring device that did not produce valid data that caused the missing hour.

(g) *Equipment Operations.* At all times, including periods of startup, shutdown, and malfunction, the owner or operator shall, to the extent practicable, maintain and operate the unit including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Regional Administrator which may include, but is not limited to, monitoring results, review of operating and maintenance procedures, and inspection of the unit.

(h) *Enforcement.* (1) Notwithstanding any other provision in this implementation plan, any credible evidence or information relevant as to whether the unit would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed, can be used to establish whether or not the owner or operator has violated or is in violation of any standard or applicable emission limit in the plan.

(2) Emissions in excess of the level of the applicable emission limit or requirement that occur due to a malfunction shall constitute a violation of the applicable emission limit.

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