ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R06–OAR–2016–0611; FRL–9955–77-Region 6]

Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: Pursuant to the Federal Clean Air Act (CAA or Act), the Environmental Protection Agency (EPA) is proposing to promulgate a Federal Implementation Plan (FIP) in Texas to address the remaining outstanding requirements that are not satisfied by the Texas Regional Haze State Implementation Plan (SIP) submission. Specifically, the EPA proposes SO_2 limits on 29 Electric Generating Units (EGUs) located at 14 Texas facilities to fulfill requirements for the installation and operation of the Best Available Retrofit Technology (BART) for SO_2. To address the requirement for NO_X BART for Texas EGU sources, we are proposing a FIP that relies upon two other EPA rulemakings, one already final and one proposed, which together will establish that participation in the Cross-State Air Pollution Rule (CSAPR) continues to qualify as an alternative to NO_X BART for EGUs in Texas. We also are proposing to disapprove the portion of the Texas Regional Haze SIP that addresses the BART requirement for EGUs for Particulate Matter (PM) and proposing a FIP with PM BART limits for EGUs at 29 EGUs located at 14 Texas facilities, based on existing practices and control capabilities. In addition, we propose to reconsider and re-propose disapproval of portions of several SIP revisions submitted to satisfy the requirement to address interstate visibility transport for six NAAQS and that the FIP emission limits we are proposing meet the interstate visibility transport requirements for these NAAQS.

DATES: *Comments:* Comments must be received on or before March 6, 2017. A public hearing will be held January 10, 2017. For additional logistical information regarding the public hearing please see the **SUPPLEMENTARY INFORMATION** section of this action.

ADDRESSES: Submit your comments, identified by Docket No. EPA–R06–OAR–2016–0611, at *http://www.regulations.gov* or via email to *R6_TX–BART@epa.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from *Regulations.gov*. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.* on the web, cloud, or other file sharing system). For additional submission methods, please contact Joe Kordzi, 214–665–7186, *Kordzi.joe@epa.gov.* For the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *http://www2.epa.gov/dockets/commenting-epa-dockets.*

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

The Texas regional haze SIP is available online at: *https://www.tceq.texas.gov/airquality/sip/bart/haze_sip.html.* It is also available for public inspection during official business hours, by appointment, at the Texas Commission on Environmental Quality, Office of Air Quality, 12124 Park 35 Circle, Austin, Texas 78753.

FOR FURTHER INFORMATION CONTACT: Joe Kordzi, Air Planning Section (6PD–L), Environmental Protection Agency, Region 6, 1445 Ross Avenue, Suite 700, Dallas, Texas 75202–2733, telephone 214–665–7186; fax number 214–665–7263; email address *Kordzi.joe@epa.gov.*

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

Public Hearing: We are holding an information session, for the purpose of providing additional information and informal discussion for our proposal. We are also holding a public hearing to accept oral comments into the record:

Date: Tuesday, January 10, 2017

Time: Open House: 1:30 p.m.–3:30 p.m.

Public hearing: 4:00 p.m.–8:00 p.m. (including short break)

Location: Joe C. Thompson Conference Center (on the University of Texas (UT) Campus), Room 3.102, 2405 Robert Dedman Drive, Austin, Texas 78712

Joe C. Thompson Conference Center parking is adjacent to the building in Lot 40, located at the intersection of East Dean Keeton Street and Red River Street. Additional parking is available at the Manor Garage, located at the intersection of Clyde Littlefield Drive and Robert Dedman Drive. If arranged in advance, the UT Parking Office will allow buses to park along Dedman Drive near the Manor Garage for a fee.

The public hearing will provide interested parties the opportunity to present information and opinions to us 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 significant oral and written comments received on our proposal. To provide opportunities for questions and discussion, we will hold an information session prior to the public hearing. During the information session, EPA staff will be available to informally answer questions on our proposed action. Any comments made to EPA staff during an information session must still be provided orally during the public hearing, or formally in writing within 30 days after completion of the hearings, in order to be considered in the record.

At the public hearings, the hearing officer may limit the time available for each commenter to address the proposal to three 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 hearings. Verbatim English language transcripts of the hearing and written statements will be included in the rulemaking docket.

Table of Contents

I. Background

Regional haze is visibility impairment that is produced by a multitude of sources and activities that are located across a broad geographic area and emit fine particulates ($PM_{2.5}$) (*e.g.,* sulfates, nitrates, Organic Carbon (OC), Elemental Carbon (EC), and soil dust), and their precursors (*e.g.,* Sulfur Dioxide (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 $PM_{2.5}$, which impairs visibility by scattering and absorbing light. Visibility impairment reduces the clarity, color, and visible distance that can be seen. $PM_{2.5}$ can also 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 parks and wilderness areas. In 1999, the average visual range [1] 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 was 100–150 kilometers, or about one-half to two-thirds of the visual range that would exist without anthropogenic air pollution. In most of the eastern Class I areas of the United States, the average visual range was less than 30 kilometers, or about one-fifth of the visual range that would exist under estimated natural conditions.[2] CAA programs have reduced some haze-causing pollution, lessening some visibility impairment and resulting in partially improved average visual ranges.[3]

CAA requirements to address the problem of visibility impairment are continuing to be addressed and implemented. In Section 169A of the 1977 Amendments to the CAA, Congress created a program for protecting visibility in the nation's national parks and wilderness areas. This section of the CAA establishes as a national goal the prevention of any future, and the remedying of any existing man-made impairment of visibility in 156 national parks and wilderness areas designated as mandatory Class I Federal areas.[4] On December 2, 1980, EPA 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.'' [5] These regulations represented the first phase in addressing visibility impairment. EPA deferred action on regional haze 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 regional haze issues, and we promulgated regulations addressing regional haze in 1999.[6] The Regional Haze Rule revised the existing visibility regulations to integrate into the regulations provisions addressing regional haze impairment and established a comprehensive visibility protection program for Class I areas. The requirements for regional haze, found at 40 CFR 51.308 and 51.309, are included in our visibility protection regulations at 40 CFR 51.300–309. The requirement to submit a regional haze SIP applies to all 50 states, the District of Columbia, and the Virgin Islands. States were required to submit the first implementation plan addressing regional haze visibility

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

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

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

[4] Areas designated as mandatory Class I Federal areas consist of National Parks exceeding 6000 acres, wilderness areas and national memorial parks exceeding 5000 acres, and all international parks that were in existence on August 7, 1977. 42 U.S.C. 7472(a). In accordance with section 169A of the CAA, EPA, in consultation with the Department of Interior, promulgated a list of 156 areas where visibility is identified as an important value. 44 FR 69122 (November 30, 1979). The extent of a mandatory Class I area includes subsequent changes in boundaries, such as park expansions. 42 U.S.C. 7472(a). Although states and tribes may designate as Class I additional areas which they consider to have visibility as an important value, the requirements of the visibility program set forth in section 169A of the CAA apply only to ''mandatory Class I Federal areas.'' Each mandatory Class I Federal area is the responsibility of a ''Federal Land Manager.'' 42 U.S.C. 7602(i). When we use the term ''Class I area'' in this action, we mean a ''mandatory Class I Federal area.''

[5] 45 FR 80084 (December 2, 1980).

[6] 64 FR 35714 (July 1, 1999), codified at 40 CFR part 51, subpart P (Regional Haze Rule).

impairment no later than December 17, 2007.[7]

Section 169A of the CAA directs states to evaluate the use of retrofit controls at certain larger, often under-controlled, older stationary sources in order to address visibility impacts from these sources. Specifically, section 169A(b)(2)(A) of the CAA requires states to revise their SIPs to contain such measures as may be necessary to make reasonable progress toward the natural visibility goal, including a requirement that certain categories of existing major stationary sources [8] built between 1962 and 1977 procure, install and operate the ''Best Available Retrofit Technology'' (BART). Larger ''fossil-fuel fired steam electric plants'' are included among the BART source categories. Under the Regional Haze Rule, states are directed to conduct BART determinations for ''BART-eligible'' sources that may be anticipated to cause or contribute to any visibility impairment in a Class I area. The evaluation of BART for Electric Generating Units (EGUs) that are located at fossil-fuel fired power plants having a generating capacity in excess of 750 megawatts must follow the ''Guidelines for BART Determinations Under the Regional Haze Rule'' at appendix Y to 40 CFR part 51 (hereinafter referred to as the ''BART Guidelines''). Rather than requiring source-specific BART controls, states also have the flexibility to adopt an emissions trading program or alternative program as long as the alternative provides greater reasonable progress towards improving visibility than BART. To the extent a Regional Haze SIP does not meet CAA requirements to address BART, the CAA requires EPA to promulgate a FIP that makes the requisite determinations to ensure the BART requirement is satisfied, as applicable, for sources in the state.[9]

II. Overview of Proposed Actions

A. Regional Haze

On January 5, 2016, we took final action on nearly all portions of a Regional Haze SIP submittal submitted by the State of Texas on March 31, 2009.[10] In that final rule, we did not take action on the portion of the submittal that was intended to satisfy BART requirements for EGUs as mandated by 40 CFR 51.308(e). In an earlier, separate action, we issued a limited disapproval of the Texas Regional Haze SIP concerning EGU BART due to Texas' reliance on the Clean Air Interstate Rule (CAIR).[11] The EGU BART requirements for NO_X and SO_2 remain unmet following the limited disapproval, and Texas has not submitted a revised SIP to address the deficiencies. While we previously proposed to approve the portion of the Regional Haze SIP that was intended to address whether EGUs in Texas must install and operate BART for PM,[12] that part of the proposed action was not finalized.[13] In connection with changed circumstances on how Texas EGUs are able to satisfy NO_X and SO_2 BART, we are now proposing to disapprove the portion of the Texas Regional Haze SIP that evaluated the PM BART requirement for EGUs. The FIP we are proposing today addresses the EGU BART requirement and addresses these deficiencies in the Texas Regional Haze SIP.

Texas' regional haze SIP relied on participation in CAIR as an alternative to meeting the source-specific BART requirements for SO_2 and NO_X. *See* 40 CFR 51.308(e)(4) (2006). At the time that Texas submitted its SIP to EPA, however, the D.C. Circuit had remanded CAIR (without vacatur). *See North Carolina* v. *EPA,* 531 F.3d 896 (D.C. Cir.), *modified,* 550 F.3d 1176 (D.C. Cir. 2008). The court thereby left CAIR and CAIR FIPs in place in order to ''temporarily preserve the environmental values covered by CAIR'' until we could, by rulemaking, replace CAIR consistent with the court's opinion.[14]

On August 8, 2011, we promulgated the Cross-State Air Pollution Rule (CSAPR), to replace CAIR.[15] In 2012, we issued a limited disapproval of the Texas regional haze SIP because of Texas' reliance on CAIR as an alternative to EGU BART for SO_2 and NO_X.[16] We also determined that CSAPR would provide for greater reasonable progress than BART and amended the Regional Haze Rule to allow CSAPR participation as an alternative to source-specific SO_2 and NO_X BART for EGUs.[17] CSAPR has been subject to extensive litigation, and on July 28, 2015, the D.C. Circuit issued a decision generally upholding CSAPR but remanding without vacating the CSAPR emissions budgets for a number of states in *EME Homer City Generation* v. *EPA,* 795 F.3d 118 (D.C. Cir.). Specifically, the court invalidated a number of the Phase 2 ozone-season NO_X budgets and found that the SO_2 budgets for four states resulted in over-control for purposes of CAA section 110(a)(2)(D)(i)(I). The remand included Texas' ozone-season NO_X budget and annual SO_2 budget.

We had earlier proposed to rely on CSAPR participation to address these BART-related deficiencies in Texas' SIP submittals.[18] Because of the uncertainty caused by the D.C. Circuit Court's partial remand, however, we determined that it was not appropriate to finalize our action. We are in the process of responding to the remand of these CSAPR budgets. On October 26, 2016, we finalized an update to the CSAPR rule that addresses the 1997 ozone NAAQS portion of the remand and the requirements of CAA section 110(a)(2)(D)(i)(I) for the 2008 ozone NAAQS.[19] This rule promulgated a new

[7] See 40 CFR 51.308(b). EPA's regional haze regulations require subsequent updates to the regional haze SIPs. 40 CFR 51.308(g)–(i).

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

[9] See, 42 U.S.C. 7491(b)(2)(A)(citing the potential need for BART as determined by ''the Administrator in the case of a plan promulgated under section 7410(c) of this title'').

[10] 81 FR 296 (January 5, 2016). A preliminary order of the Fifth Circuit Court of Appeals in Case No. 16–60118 was issued on July 15, 2016, and stayed the rule ''in its entirety.'' On December 2, 2016, the U.S. Department of Justice filed a motion for voluntary remand of the parts of the rule under challenge and consenting to continuation of the judicial stay for remanded parts of the rule. The motion also requested affirmance of the partial approvals of the Texas and Oklahoma SIPs and lifting of the stay as to those approvals. This motion is currently pending disposition.

[11] The limited disapproval triggered the EPA's obligation to issue a FIP for Texas unless the State submitted an approvable SIP revision to correct the relevant deficiencies within 2 years of the final limited disapproval action. CAA section 110(c)(1); 77 FR 33641, 33654 (August 6, 2012).

[12] 79 FR 74817, 74851 (proposing to concur with screening analyses conducted by TCEQ including findings that no Texas EGUs are subject to BART for PM).

[13] 81 FR at 302 (January 5, 2016): ''[W]e proposed to approve Texas' determination that for its EGUs no PM BART controls were appropriate, based on a screening analysis of the visibility impacts of from just PM emissions. . . ..we have. . . .decided not to finalize our proposed approval of Texas' PM BART determination [for EGUs].''

[14] 550 F.3d at 1178.

[15] 76 FR 48208.

[16] 77 FR 33641.

[17] While that rulemaking also promulgated FIPs for several states to replace reliance on CAIR with reliance on CSAPR as an alternative to BART, it did not include a FIP for Texas. 77 FR 33641, 33654.

[18] 79 FR 74817, 74823 (December 16, 2014).

[19] ''Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS.'' 81 FR74504. The relevant portion of the remand pertained to the Phase 2 ozone season NO_X emission budget designed to address the 1997 ozone NAAQS. In response to the remand, in this final rule the EPA removed the regulatory requirement for sources in Texas to comply with the phase 2 ozone season NO_X budget calculated to address the 1997 ozone standard because we determined that no additional emission reductions from sources in Texas are necessary to address the State's obligation under 110(a)(2)(D)(i)(I) for the 1997 ozone NAAQS. However, because Texas is linked to downwind air quality problems with respect to the 2008 ozone NAAQS, we promulgated a new ozone season NO_X emission budget to address that standard. 81 FR 74504, 74600–74601.

FIP for Texas that replaced the CSAPR ozone season NO_X emission budget designed to address the 1997 ozone NAAQS for the State with a revised budget designed to address the requirements of CAA section 110(a)(2)(D)(i)(I) for the 2008 ozone NAAQS. Then, on November 10, 2016, we proposed to withdraw the FIP provisions that require affected EGUs in Texas to participate in CSAPR for annual emissions of SO_2 and NO_X with regard to emissions after 2016.[20] Withdrawal of these FIP requirements will address the D.C. Circuit's remand of the CSAPR Phase 2 SO_2 budget for Texas. This recently published proposed rule includes an assessment of the impacts of the set of actions that the EPA has taken or expects to take in response to the D.C. Circuit's remand on our 2012 demonstration that participation in CSAPR would provide for greater reasonable progress than BART.

In 2012, we determined that CSAPR is ''better-than-BART'' based on a comparison of projected visibility in scenarios representing CSAPR implementation and BART implementation, as well as a base case without CSAPR or BART, in relevant locations throughout the country. In the case of the remanded Phase 2 ozone-season NO_X budgets, eight of the states with remanded budgets (including Texas) will continue to be subject to CSAPR to address ozone transport obligations with regard to the more stringent 2008 ozone NAAQS, and North Carolina and South Carolina, although no longer covered by CSAPR to address ozone transport obligations, will continue to be subject to CSAPR annual NO_X requirements in order to address their $PM_{2.5}$ transport obligations. In considering the potential impact of the remand of Phase 2 budgets on the 2012 CSAPR-Better-than-BART analytic demonstration, we therefore believe that only two changes have potential relevance: The withdrawal of the FIP provisions subjecting Florida EGUs to CSAPR ozone-season NO_X requirements that has already been finalized, and the withdrawal of FIP provisions subjecting Texas EGUs to CSAPR SO_2 and annual NO_X requirements that is proposed separately. That proposed analysis supports the continued conclusion that CSAPR participation would achieve greater reasonable progress than BART for NO_X despite the change in the treatment of Texas and Florida EGUs. Consequently, we have proposed that the Regional Haze Rule continues to authorize the use of CSAPR participation as a BART alternative for EGUs.[21] Finalization of that proposal would allow for Texas' regional haze program to rely on CSAPR ozone season control program participation as an alternative to source-specific EGU BART for NO_X.[22] Based on that national proposal, we are now proposing a FIP to replace Texas' reliance on CAIR with reliance on CSAPR to address the NO_X BART requirements for EGUs. Finalization of this portion of the FIP is contingent on our taking final action to find that CSAPR continues to be an appropriate alternative to source specific BART. However, finalization of the portion of our national proposal that would withdraw the FIP provisions for Texas for annual emissions of SO_2 and NO_X described above would mean that Texas will no longer be eligible to rely on CSAPR participation as an alternative to source-specific EGU BART for SO_2. As a result, we are proposing to promulgate a FIP that includes BART screening of sources and a source-by-source analysis for SO_2 BART and controls for this pollutant as appropriate. We are also unable to propose approval of the Texas Regional Haze SIP's PM BART evaluation, as previously proposed, as that demonstration made underlying assumptions that are no longer valid.[23] We instead propose to disapprove that portion of the SIP and, in place of it, promulgate source-specific PM BART requirements for EGUs that we have evaluated to be subject to BART in this proposed FIP.

We believe, however, it is preferable for states to assume primary responsibility for implementing the Regional Haze requirements as envisioned by the CAA. We will work with the State of Texas if it chooses to develop a SIP to meet these overdue Regional Haze requirements and replace or avoid a finalized FIP.

The FIP we are proposing includes BART control determinations for EGUs in Texas without previously approved BART determinations and associated compliance schedules and requirements for equipment maintenance, monitoring, testing, recordkeeping, and reporting for all affected sources and units. The EGU BART sources addressed in this FIP cause or contribute to visibility impairment at one or more Class I areas in Texas, Oklahoma, Arkansas, and New Mexico. The two Class I areas in Texas are Big Bend National Park and the Guadalupe Mountains National Park. The Class I area in Oklahoma is the Wichita Mountains National Wildlife Refuge. The two Class I areas in Arkansas are the Caney Creek Wilderness Area and the Upper Buffalo Wilderness Area. The closest impacted Class I areas in New Mexico are the Carlsbad Caverns National Park, Salt Creek Wilderness Area, and White Mountains Wilderness Area.

In order to remedy these deficiencies in the Texas SIP, we are proposing this FIP to establish the means by which the regional haze program for Texas will meet the BART requirements for SO_2, NO_X, and PM. We are proposing source-specific BART determinations for EGUs subject to BART for SO_2 and PM. We are proposing that NO_X BART requirements for EGUs in Texas will be satisfied by a determination, proposed for separate finalization, that Texas' participation in CSAPR's ozone season control program is a permissible alternative to source-specific NO_X BART.

Addressing the BART requirement for Texas EGUs, as proposed today, with cost-effective and readily available controls, will help ensure that progress

[20] ''Interstate Transport of Fine Particulate Matter: Revision of Federal Implementation Plan Requirements for Texas,'' 81 FR 78954 (November 10, 2016). Although the court's decision specifically remanded only Texas' SO_2 budget, the court's rationale for remanding that budget also implicates Texas' annual NO_X budget because the SO_2 and annual NO_X budgets were developed through an integrated analysis and were promulgated to meet a common $PM_{2.5}$ transport obligation under CAA section 110(a)(2)(D)(i)(I).

[21] 81 FR at 78962–78964.

[22] While we have proposed to remove Texas from CSAPR's annual NO_X program, CSAPR is still an appropriate alternative to BART for NO_X purposes because EGUs in Texas continue to be required to participate in CSAPR's ozone season NO_X program.

[23] We previously proposed approval of Texas' SIP for EGU PM BART on the premise that EGU BART for both SO_2 and NO_X were covered by participation in CSAPR, which allowed Texas to conduct a screening analysis of the visibility impacts from PM emissions in isolation. However, modeling on a pollutant-specific basis for PM is appropriate only in the narrow circumstance where a state relies on a BART alternative to satisfy NO_X and SO_2 BART. Due to the complexity and nonlinear nature of atmospheric chemistry and chemical transformation among pollutants, EPA has not recommended performing modeling on a pollutant-specific basis to determine whether a source is subject to BART, except in the unique situation described above. See discussion in Memorandum from Joseph Paisie to Kay Prince, ''Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations,'' July 19, 2006. More recently, the Ninth Circuit upheld EPA's disapproval of the Arizona regional haze SIP for including a pollutant-specific screening analysis for NO_X. *Phoenix Cement Co.* v. *EPA,* 647 F. App'x 702, 705–06 (9th Cir. Mar. 31, 2016) (upholding EPA's interpretation that the ''Regional Haze Rule [] require[s] a BART determination for any pollutant at a source that exceeds the de minimis threshold, once that source has been determined subject to BART.''). We did not finalize our proposed approval of Texas' EGU PM BART determination because of the uncertainty at that time concerning the CSAPR remand and whether Texas would continue to have CSAPR coverage for both NO_X and SO_2, 81 FR 296, 302, but that uncertainty has now been resolved.

is made toward natural visibility conditions at Class I areas affected by Texas' sources. Please refer to our previous rulemaking on the Texas regional haze SIP for additional background regarding the CAA, regional haze, and our Regional Haze Rule.[24]

B. Interstate Transport of Pollutants That Affect Visibility

Section 110(a) of the CAA directs states to submit a SIP that provides for the implementation, maintenance, and enforcement of each NAAQS, which is commonly referred to as an infrastructure SIP. Among other things, CAA 110(a)(2)(D)(i)(II) requires that SIPs contain adequate provisions to prohibit interference with measures required to protect visibility in other states. This requirement is referred to as ''interstate visibility transport.'' SIPs addressing interstate visibility transport are due to EPA within three years after the promulgation of a new or revised NAAQS (or within such shorter period as we may prescribe). A state's failure to submit a complete, approvable SIP for interstate visibility transport creates an obligation for EPA to promulgate a FIP to address this requirement.[25]

Previously, we issued a finding that Texas failed to submit a SIP revision to satisfy all four requirements of interstate transport under section 110(a)(2)(D)(i) of the CAA for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS.[26] Texas later submitted a SIP revision to address interstate transport for these NAAQS. However, in our January 5, 2016 final action we disapproved the portion of Texas' SIP revisions intended to address interstate visibility transport for six NAAQS, including the 1997 8-hour ozone and 1997 $PM_{2.5}$.[27] We concluded that to meet the requirements of interstate visibility transport: (1) Texas could not rely on its Regional Haze SIP, which relied heavily upon the remanded CAIR, to ensure that emissions from Texas do not interfere with measures to protect visibility in nearby states; and (2) additional control of SO_2 emissions in Texas were needed to prevent interference with measures required to be included in the Oklahoma SIP to protect visibility. However, in that action we did not finalize the portion of our proposed FIP addressing Texas' interstate visibility transport obligations because that portion of the proposed FIP would have partially relied on CSAPR to ensure the emissions from Texas' sources do not interfere with other states' visibility programs. Given the uncertainty that existed at the time arising from the D.C. Circuit's remand of Texas' CSAPR budgets (*EME Homer City Generation* v. *EPA,* 79 F.3d 118 (D.C. Cir.)), we concluded that it was not appropriate to finalize our proposed determination to rely on CSAPR as an alternative to SO_2 and NO_X BART for EGUs in Texas in that action.[28]

Our prior disapproval of interstate visibility transport for the six NAAQS is currently stayed by the Fifth Circuit.[29] We recognize that because our prior disapproval of the Texas SIP submittals addressing interstate visibility transport relied in part on our determinations of the measures needed in Texas to ensure reasonable progress in Oklahoma, the Fifth Circuit's stay of our previous action complicates next steps to ensure that the visibility requirements of CAA 110(a)(2)(D)(i)(II) are met. The Court's stay accordingly calls into question whether our past disapprovals for interstate visibility transport would stand. At the same time, we also note that we continue to have an obligation to issue a FIP for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS as a result of our 2005 finding that Texas failed to timely submit SIPs to address the interstate transport visibility requirements. Given the uncertainties arising from the Fifth Circuit's stay of our prior disapproval, we are now proposing to reconsider the basis of our prior disapproval of Texas' SIP submittals addressing the interstate visibility transport requirement for all six NAAQS. We are now proposing to determine that Texas' SIP submittals addressing interstate visibility transport for the six NAAQS are not approvable because these submittals relied solely on Texas' Regional Haze SIP to ensure that emissions from Texas did not interfere with required measures in other states. Texas' Regional Haze SIP, in turn, relied on the implementation of CAIR as an alternative to EGU BART for SO_2 and NO_X. Specifically, we are proposing disapproval of the following Texas SIP submittals insofar as they address the interstate visibility transport requirement: April 4, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); May 1, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); November 23, 2009: 2006 24-hour $PM_{2.5}$; December 7, 2012: 2010 NO_2; December 13, 2012: 2008 8-hour Ozone; May 6, 2013: 2010 1-hour SO_2 (Primary NAAQS). Texas has not submitted a SIP revision to remove reliance on CAIR for Regional Haze or interstate visibility transport. As CAIR is no longer in effect and has been replaced by CSAPR, we are proposing to find that Texas' Regional Haze SIP does meet its interstate visibility transport obligations. As a result, the Texas SIPs to address interstate visibility transport for these six NAAQS continue to be unapprovable.

We are proposing a FIP to cure the deficiencies in Texas' Regional Haze Program concerning EGU BART. This FIP will replace reliance on CAIR with reliance on CSAPR to meet the requirements for EGU BART for NO_X in Texas. The FIP will also address Texas EGU BART for SO_2 and PM on a source-specific basis. With the absence of CSAPR coverage for SO_2, we must reevaluate what is needed in Texas to address interstate visibility transport. Our proposed FIP to address Texas EGU BART achieves significant reductions of SO_2, which exceed the reductions initially assumed for Texas under either CAIR or CSAPR. In addition, our proposed FIP achieves reductions at large sources of SO_2 emissions (*e.g.,* Monticello, Martin Lake and Big Brown), that have significant impacts on

[24] 81 FR 296. The public docket for this past rulemaking remains accessible under EPA Docket ID: EPA–R06–OAR–2014–0754 at *https://www.regulations.gov.* This proposed rulemaking has a separately established docket (EPA–R06–OAR–2016–0611). Our TSD contains a list of materials from EPA Docket ID: EPA–R06–OAR–2014–0754 that we incorporate by reference and consider to be part of this rulemaking record even as they are not necessarily re-uploaded to the newer docket.

[25] CAA § 110(c)(1). Mandatory sanctions under CAA section 179 do not apply because the deficiencies are not with respect to a submission that is required under CAA title I part D. ''Guidance on Infrastructure State Implementation Plan (SIP) Elements under Clean Air Act Sections 110(a)(1) and (2)'' at pages 34–35 (September 13, 2013) [hereinafter 2013 i-SIP Guidance].

[26] 70 FR 21147 (April 25, 2005). The four components of interstate transport in Section 110(a)(2)(D)(i) are contained in two subsections. Section 110(a)(2)(D)(i)(I) addresses any emissions activity in one state that contributes significantly to nonattainment, or interferes with maintenance, of the NAAQS in another state. Section 110(a)(2)(D)(i)(II) requires SIPs to include provisions prohibiting any source or other type of emissions activity in one state from interfering with measures required of any other state to prevent significant deterioration of air quality or from interfering with measures required of any other state to protect visibility (referring to visibility in Class I areas). This proposal only addresses the fourth requirement concerning visibility.

[27] Specifically, we previously disapproved the relevant portion of these Texas' SIP submittals: April 4, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); May 1, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); November 23, 2009: 2006 24-hour $PM_{2.5}$; December 7, 2012: 2010 NO_2; December 13, 2012: 2008 8-hour Ozone; May 6, 2013: 2010 1-hour SO_2 (Primary NAAQS). 79 FR 74818, 74821; 81 FR 296, at 302.

[28] 81 FR 296, 301–2.

[29] July 15, 2016 Order in *Texas* v. *EPA* (Fifth Cir. Case No. 16–160118). The EPA's filed motion requesting voluntary partial remand and continuation of the judicial stay for remanded parts of the rule includes our prior disapproval of Texas' SIPs concerning interstate visibility transport. This motion is currently pending disposition.

Class I areas in nearby states. The BART FIP requires controls on many but not all of the sources that were controlled in our previous partial FIP for Texas Regional Haze. The EGU BART FIP also includes control requirements at some additional sources not controlled in our previous action on Texas Regional Haze.

We are proposing to find that our proposed EGU BART FIP is adequate to prevent interference with measures required to protect visibility in other states for the first planning period.[30] We, therefore, propose that the measures in our proposed FIP to address Texas EGU BART will fully address Texas' interstate visibility transport obligations for the six NAAQS (1997 8-hour ozone, 1997 $PM_{2.5}$, 2006 $PM_{2.5}$, 2008 8-hour ozone, 2010 1-hour NO_2, and 2010 1-hour SO_2). We also propose that reliance on CSAPR for EGU NO_X BART is appropriate to ensure NO_X emissions from Texas EGUs do not interfere with other states' measures to protect visibility. We are proposing this action based on the reasoning that our BART FIP will achieve more emission reductions than projected under CAIR or CSAPR and the reductions are occurring at sources that have particularly large impacts on Class I areas outside of Texas. To the extent our previous final action concerning Texas Regional Haze is remanded by a Court or otherwise reconsidered in the future, we may revisit whether controls in the EGU BART FIP are adequate to address interstate visibility transport requirements. Nonetheless, we are here proposing that the proposed EGU BART FIP measures will be adequate to address interstate visibility transport based on current information. This proposal concerning the adequacy of the proposed FIP remedy does not depend on our earlier action on the Texas Regional Haze SIP or hinge on its disposition, nor does it foreclose that we may reexamine visibility transport concerns under potential scenarios where we have a responsibility to take new action.[31]

We encourage Texas to consider adopting additional SIP provisions that would allow the EPA to fully approve the Regional Haze SIP and thus to withdraw the FIP and approve Texas' SIP with respect to interstate visibility transport. Texas may also elect to satisfy interstate visibility transport by providing, as an alternative to relying on its Regional Haze SIP alone, a demonstration that emissions within its jurisdiction do not interfere with other states' plans to protect visibility.[32]

C. Our Obligation To Promulgate a FIP

Under section 110(c) of the CAA, whenever we disapprove a mandatory SIP submission in whole or in part, we are required to promulgate a FIP within 2 years unless we approve a SIP revision correcting the deficiencies before promulgating a FIP. Specifically, CAA section 110(c) provides that the Administrator shall promulgate a FIP within 2 years after the Administrator disapproves a state implementation plan submission ''unless the State corrects the deficiency, and the Administrator approves the plan or plan revision, before the Administrator promulgates such Federal implementation plan.'' [33] The term ''Federal implementation plan'' is defined in Section 302(y) of the CAA in pertinent part as a plan promulgated by the Administrator to correct an inadequacy in a SIP.

Beginning in 2012, following the limited disapproval of the Texas Regional Haze SIP, EPA had the authority and obligation to promulgate a FIP to address BART for Texas EGUs for NO_X and SO_2. In proposing to disapprove the Regional Haze SIP component that sought to address the PM BART requirement for Texas EGUs, we also have the obligation to promulgate a PM BART FIP to address the deficiency. Texas has not addressed the EGU BART disapproval, and that requirement is now significantly overdue.[34] We are accordingly empowered and required by the CAA to make determinations and promulgate a FIP to ensure the BART requirement for Texas EGUs is satisfied.

Adding to this background, beginning with our January 5, 2016 disapproval of Texas SIP provisions regarding interstate visibility transport, we obtained the authority and obligation to promulgate a FIP to correct the deficiencies relating to that CAA requirement.[35] As with the BART requirement, we lack a SIP revision that would have any potential to correct the deficiency, necessitating that we now take action under FIP authority.

III. Our Proposed BART Analyses for SO_2 and PM

In our previous action,[36] we determined that due to the CSAPR remand, it was not appropriate at that time to rely on CSAPR as an alternative to SO_2 and NO_X BART for EGUs in Texas. As a consequence, action to satisfy the overdue requirement to address BART for EGUs in the state of Texas was further delayed.[37] In this proposal, we are proposing that CSAPR, once fully revised to address the D.C. Circuit's remand, provides a basis for satisfying EGU BART obligations for NO_X alone. It remains the case that we cannot rely on CSAPR as an alternative to SO_2 BART for Texas EGUs as further confirmed by our proposed action to remove Texas from the annual NO_X and SO_2 control programs. Thus, we have the obligation to consider source-specific requirements for Texas EGUs consistent with the BART Guidelines for SO_2 BART.

Because the component of the Texas Regional Haze SIP regarding the PM BART requirement for EGUs has not been acted on, we have the responsibility under CAA section 110(k) to evaluate the submission and take action to approve or disapprove it. The SIP determinations for PM were based on modeling that was conducted by examining visibility impairment due to PM emissions alone, based on the assumption that the state would be participating in CAIR for SO_2 and NO_X and thereby having BART coverage for those pollutants. The Texas Regional Haze SIP had concluded that no PM BART controls for EGUs were appropriate, because modeling assessment of PM impacts alone showed their impacts to be too small to warrant control consideration. But Texas' screening analysis is no longer reliable or accurate because of the invalid assumption that source-by-source BART for either SO_2 or NO_X would not be

[30] This proposed FIP for interstate visibility transport is premised on the interpretation that this requirement can be addressed even when a Regional Haze SIP is not fully approved and the FIP does not purport to correct all Regional Haze SIP deficiencies. *See e.g.* 76 FR 52388 (August 22, 2011); 76 FR 22036 (April 20, 2011); and 78 FR 14681 (March 7, 2013); *see also,* 2013 i-SIP Guidance, at page 34 (stating that EPA may find it appropriate to supplement the i-SIP Guidance regarding the relationship between Regional Haze SIPs and interstate visibility transport for future planning periods).

[31] *See e.g.* 78 FR 14681, 14685.

[32] 2013 i-SIP Guidance, at pages 34–35.

[33] EPA additionally has the authority to promulgate a FIP any time after finding that ''a State has failed to make a required submission'' of a SIP. CAA section 110(c)(1)(A); 42 U.S.C. 7410(c)(1)(a).

[34] The Texas Regional Haze SIP stated, ''The TCEQ will take appropriate action if CAIR is not replaced with a system that the US EPA considers to be equivalent to BART.'' BART determinations were due in SIP submissions on December 17, 2007, 40 CFR 51.308(b), putting them on a timeline for controls by 2014 (considering the deadline for SIP action at CAA section 110(k)(2) and allowing five years for installation of BART controls). Additional delay of any amount is not appropriate and not consistent with the law.

[35] Additionally, we continue to have authority to issue a FIP to address interstate visibility transport for 1997 8-hour ozone and 1997 $PM_{2.5}$ due to our 2005 finding that Texas failed to submit SIPs to address interstate transport for these NAAQS under CAA section 110(a)(2)(D)(i). 70 FR 21147.

[36] See the discussion beginning on 81 FR 301 (January 5, 2016).

[37] Id. at 346.

required. In order to appropriately evaluate the BART requirements for EGUs, the visibility impacts from all pollutants must be studied, including PM emissions. Texas' PM BART analysis for EGUs does not do this.[38]

Accordingly, we are proposing to disapprove the portion of the Texas Regional Haze SIP that determined that all Texas EGUs screen out of the BART requirement for PM. The basis for the proposed disapproval is the SIP determination's assumption that EGUs would have coverage for SO_2 and NO_X BART under an alternative measure.[39] Since that assumption is not valid, the technical determinations regarding PM BART cannot be approved. Following the directions of the BART Guidelines on how to identify sources ''subject to BART,'' we have looked at all visibility impairing pollutants from EGUs that are BART-eligible. Our proposed FIP therefore seeks to fill that regulatory gap by assessing BART for Texas EGUs for visibility impairing pollutants other than NO_X, *i.e.,* SO_2 and PM.

A. Identification of BART-Eligible Sources

The BART Guidelines set forth the steps for identifying whether the source is a BART-eligible source: [40]

Step 1: Identify the emission units in the BART categories,

Step 2: Identify the start-up dates of those emission units, and

Step 3: Compare the potential emissions to the 250 ton/yr cutoff.

Following our 2016 final action on the March 31, 2009 Texas RH SIP, we began the process of generating additional technical information and analysis in order to address the above three steps in our BART-eligibility proposal. We started with Texas' facility-specific listing of BART-eligible EGU sources and removed sources we verified had retired. We then gathered additional information from (1) our authority under Section 114(a) of the CAA to request information from potential BART-eligible sources, and (2) the U.S. Energy Information Administration (EIA). We then converted Texas' facility-specific BART-eligible list to a unit-specific BART-eligible list and verified the BART-eligibility of each unit. The following is a list of units we propose have satisfied the above three steps and are BART-eligible: [41]

TABLE 1—SUMMARY OF BART-ELIGIBILITY ANALYSIS

Facility	Unit
Barney M. Davis (Talen/Topaz)	1.
Big Brown (Luminant)	1.
Big Brown (Luminant)	2.
Cedar Bayou (NRG)	CBY1.
Cedar Bayou (NRG)	CBY2.
Coleto Creek (Engie)	1.
Dansby (City of Bryan)	1.
Decker Creek (Austin Energy)	1.
Decker Creek (Austin Energy)	2.
Fayette (LCRA)	1.
Fayette (LCRA)	2.
Graham (Luminant)	2.
Greens Bayou (NRG)	5.
Handley (Exelon)	3.
Handley (Exelon)	4.
Handley (Exelon)	5.
Harrington Station (Xcel)	061B.
Harrington Station (Xcel)	062B.
J T Deely (CPS Energy)	1.
J T Deely (CPS Energy)	2.
Jones Station (Xcel)	151B.
Jones Station (Xcel)	152B.
Knox Lee Power Plant (AEP)	5.
Lake Hubbard (Luminant)	1.
Lake Hubbard (Luminant)	2.
Lewis Creek (Entergy)	1.
Lewis Creek (Entergy)	2.
Martin Lake (Luminant)	1.
Martin Lake (Luminant)	2.
Martin Lake (Luminant)	3.
Monticello (Luminant)	1.
Monticello (Luminant)	2.
Monticello (Luminant)	3.
Newman (El Paso Electric)	2.
Newman (El Paso Electric)	3.
Newman (El Paso Electric)	4.
Nichols Station (Xcel)	143B.
O W Sommers (CPS Energy)	1.
O W Sommers (CPS Energy)	2.
Plant X (Xcel)	4.
Powerlane (City of Greenville)	ST1.
Powerlane (City of Greenville)	ST2.
Powerlane (City of Greenville)	ST3.
R W Miller (Brazos Elec. Coop)	1.
R W Miller (Brazos Elec. Coop)	2.
R W Miller (Brazos Elec. Coop)	3.
Sabine (Entergy)	2.
Sabine (Entergy)	3.
Sabine (Entergy)	4.
Sabine (Entergy)	5.
Sim Gideon (LCRA)	1.
Sim Gideon (LCRA)	2.
Sim Gideon (LCRA)	3.
Spencer (City of Garland)	4.
Spencer (City of Garland)	5.
Stryker Creek (Luminant)	ST2.
Trinidad (Luminant)	6.
Ty Cooke (City of Lubbock)	1.
Ty Cooke (City of Lubbock)	2.
V H Braunig (CPS Energy)	1.
V H Braunig (CPS Energy)	2.
V H Braunig (CPS Energy)	3.
W A Parish (NRG)	WAP4.
W A Parish (NRG)	WAP5.
W A Parish (NRG)	WAP6.
Welsh Power Plant (AEP)	1.
Welsh Power Plant (AEP)	2.
Wilkes Power Plant (AEP)	1.
Wilkes Power Plant (AEP)	2.
Wilkes Power Plant (AEP)	3.

The final step in identifying a ''BART-eligible source'' is to use the information from the previous three steps to identify the collection of emissions units that comprise the BART-eligible source.

B. Identification of Sources That Are Subject to BART

Following our compilation of the BART-eligible sources in Texas, we examined whether these sources cause or contribute to visibility impairment in nearby Class I areas.[42] For those sources that are not reasonably anticipated to cause or contribute to any visibility impairment in a Class I area, a BART determination is not required. Those sources are determined to be not subject-to-BART. Sources that are reasonably anticipated to cause or contribute to any visibility impairment in a Class I area are determined to be subject-to-BART. For each source subject to BART, 40 CFR 51.308(e)(1)(ii)(A) requires that states (or EPA, in the case of a FIP) identify the level of control representing BART after considering the factors set out in CAA section 169A(g). The BART guidelines discuss several approaches available to exempt sources from the BART determination process, including modeling individual sources and the use of model plants. To determine which sources are anticipated to contribute to visibility impairment the BART guidelines state that CALPUFF or another appropriate model can be used to predict the visibility impacts from a single source at a Class I area. We employed a four-fold strategy in determining which units should or should not be subject to BART. A flowchart of the analysis along with a detailed discussion of the subject-to-BART screening analysis is provided in

[38] Texas' Regional Haze SIP determined whether its sources should be subject to review for PM controls by only looking at the impact of PM emissions on visibility. This approach is only appropriate when a state satisfies the requirements for BART for SO_2 and NO_X with an alternative measure. Additionally, as reflected in our TSD on the identification of BART-Eligible Sources, the Texas SIP neglected to identify several BART-eligible sources; this also shows error in the state's PM BART demonstration and conclusions, and it constitutes grounds for the proposed partial SIP disapproval for PM BART.

[39] The requirements for ''emissions trading programs or other alternative measures'' that may be implemented rather than requiring BART are provided at 40 CFR 51.308(e)(2).

[40] 70 FR 39158 (July 6, 2005).

[41] See our BART FIP TSD for more information concerning how we selected the units we are proposing are BART-eligible and other details concerning our proposed BART determinations.

[42] See 40 CFR part 51, Appendix Y, III, How to Identify Sources ''Subject to BART''.

the BART Screening TSD.[43] We summarize the methodology and results of this analysis here.

First, we examined whether any of the BART-eligible units should be eliminated from consideration based on the standard model plant exemptions described in the BART Guidelines.[44] Second, we created specific model plants between sources and nearby Class I areas and conducted CALPUFF modeling to evaluate a number of sources for exemption. Third, we performed stand-alone, source specific CALPUFF modeling on a number of units to determine if their visibility impacts were large enough to identify them as being subject to BART. Fourth, for those remaining units outside of the CALPUFF model's range, we contracted to have CAMx modeling performed to determine if their visibility impacts were large enough to merit their being subject to BART. These steps are further described below.

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 preamble advises that, ''for purposes of determining which sources are subject to BART, States should consider a 1.0 deciview change or more from an individual source to ''cause'' visibility impairment, and a change of 0.5 deciviews to ''contribute'' to impairment.'' [45] It further advises that ''States should have discretion to set an appropriate threshold depending on the facts of the situation,'' 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 dv,'' and describes situations in which states may wish to exercise their discretion to set lower thresholds, mainly in situations in which a large number of BART-eligible sources within the State and in proximity to a Class I area justify this approach. We do not believe that the sources under consideration in this rule, most of which are not in close proximity to a Class I area, merit the consideration of a lesser contribution threshold. Therefore, our analysis employs a contribution threshold of 0.5 deciviews.

1. Our Use of the Standard BART Model Plant Exemption

As the BART Guidelines note:

> [W]e believe that a State that has established 0.5 deciviews as a contribution threshold could reasonably exempt from the BART review process sources that emit less than 500 tons per year of NO_X or SO_2 (or combined NO_X and SO_2), as long as these sources are located more than 50 kilometers from any Class I area; and sources that emit less than 1000 tons per year of NO_X or SO_2 (or combined NO_X and SO_2) that are located more than 100 kilometers from any Class I area. You do, however, have the option of showing other thresholds might also be appropriate given your specific circumstances.[46]

We applied the standard BART model plant exemption described above to the following facilities, exempting them from further analysis:

TABLE 2—STANDARD BART MODEL PLANT EXEMPT SOURCES

Facility	Units
Dansby (City of Bryan)	1.
Greens Bayou (NRG)	5.
Nichols Station (Xcel)	143B.
Plant X (Xcel)	4.
Powerlane (City of Greenville).	ST1, ST2 & ST3.
Spencer (City of Garland)	4 & 5.
Trinidad (Luminant)	6.
Ty Cooke (City of Lubbock)	1 & 2.

2. Our Extension of the BART Model Plant Exemption

As the BART Guidelines note, the standard BART model plant exemption can be extended to values other than the 500 tons/50 km and 1,000 tons/100 km scenarios discussed in the previous section. The BART Guidelines explain that: ''you may find based on representative plant analyses that certain types of sources are not reasonably anticipated to cause or contribute to visibility impairment. To do this, you may conduct your own modeling to establish emission levels and distances from Class I areas on which you can rely to exempt sources with those characteristics.'' [47]

Modeling analyses of representative plants are used to reflect groupings of specific sources with important common characteristics. We conducted CALPUFF modeling to establish emission levels and distances from Class I areas on which we could rely to exempt sources with those characteristics. In this approach, a hypothetical facility (''model plant'') is located between a group of BART-eligible sources and a Class I area. Predominant wind patterns and elevation are considered in locating the model plant such that conditions that would be anticipated to transport pollution from the group of BART-eligible sources to the Class I area are consistent with conditions anticipated to transport pollution from the model plant to the Class I area. The visibility impacts from this model plant are modeled utilizing CALPUFF following the protocol described in the BART Screening TSD. Model plant emissions are adjusted such that the modeled visibility impact (maximum of 98th percentile values for 2001, 2002, and 2003) is below the screening threshold of 0.5 dv. For each model plant, the Q/d value is calculated as the annual emissions (combined NO_X and SO_2 emissions) divided by distance to the Class I area (km) resulting in a critical Q/d value. The Q/d value for each BART-eligible source is calculated based on annual emissions based on the maximum actual 24-hr emission rate and distance to the Class I area and is then compared to the critical Q/d value. For a BART-eligible source with a lower Q/d value than the critical Q/d, it is reasonably anticipated that the visibility impact from the BART-eligible source is lower than the model plant and therefore below the screening threshold and not subject to BART. See the BART Screening TSD for additional discussion and source-specific information used in this model plant screening analysis. By this extension of the BART model plant exemption, we identified the following additional facilities that can be exempted from further analysis:

TABLE 3—EXTENDED BART MODEL PLANT EXEMPT SOURCES

Facility	Units
Barney M. Davis (Talen/Topaz).	1.
Cedar Bayou (NRG)	CBY1 & CBY2.
Decker Creek (Austin Energy)	1 & 2.
Lewis Creek (Entergy)	1 & 2.
Sabine (Entergy)	2, 3, 4 & 5.
Sim Gideon (LCRA)	1, 2 & 3.
V H Braunig (CPS Energy)	1, 2 & 3.

3. Our Use of CALPUFF Modeling To Exempt Sources From Being Subject to BART

Those sources that did not screen out using the model plant approach were modeled directly with CALPUFF if they were in a range of when CALPUFF has

[43] See our TSD, ''Our Strategy for Assessing which Units are Subject to BART for the Texas Regional Haze BART Federal Implementation Plan (BART Screening TSD)'' in our docket.

[44] See the discussion beginning on 70 FR 39104, 39162 (July 6, 2005) [40 CFR part 51, App. Y].

[45] 70 FR at 39118.

[46] 70 FR at 39163 [40 CFR part 51, App. Y].

[47] 70 FR at 39163 [40 CFR part 51, App. Y].

been previously used. Historically CALPUFF has been used at distances up to approximately 400 km. The maximum 98th percentile impact from the modeled years (calculated based on annual average natural background conditions) was compared with the 0.5 dv screening threshold following the modeling protocol described in the BART screening TSD. The BART Guidelines recommend that states use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled, unless this rate reflects periods of start-up, shutdown, or malfunction. The maximum 24-hour emission rate (lb/hr) for NO_X and SO_2 from the 2000–2004 baseline period for each source was identified through a review of the daily emission data for each BART-eligible unit from EPA's Air Markets Program Data.[48] For some BART-eligible sources, evaluation of baseline emissions revealed evidence of the installation of NO_X control technology during the baseline period. For those sources, the maximum emission rate was updated to reflect the identified maximum emission rate from the post-control portion of the baseline period. Because daily emissions are not available for PM, the annual average emission rate was doubled to approximate the 24-hr maximum emission rate for PM. See the BART Screening TSD for additional discussion and source-specific information used in the CALPUFF modeling for this portion of the screening analysis. With the use of CALPUFF modeling results, we identified the following additional facilities that can be exempted from further analysis:

TABLE 4—CALPUFF BART EXEMPT SOURCES

Facility	Units
Handley (Exelon)	3, 4 & 5.
Jones (Xcel)	151B & 152B.
Lake Hubbard (Luminant)	1 & 2.
Knox Lee (AEP)	5.
R W Miller (Brazos Elec. Coop).	1, 2 & 3.

Based on these CALPUFF screening analyses using model plant approaches and direct modeling, the following gas[49]/fuel oil fired facilities did not screen out from being subject to BART: Newman, Stryker, Graham, and Wilkes. None of the coal fired facilities screened out in our CALPUFF modeling for the facilities within CALPUFF range.

4. Our Use of CAMx Modeling To Exempt Sources From Being Subject to BART

Some of the BART-eligible sources in Texas are geographically distant from a Class I area, yet have high enough emissions that they may significantly impact visibility at Class I areas in Texas and surrounding states. However, the use of CALPUFF is not recommended for distances much greater than 300 km, and has typically not been used at distances more than approximately 400 km. To determine which sources are anticipated to contribute to visibility impairment the BART guidelines state that CALPUFF or another appropriate model can be used to predict the visibility impacts from a single source at a Class I area. CAMx provides a scientifically defensible platform for assessment of visibility impacts over a wide range of source-to-receptor distances. CAMx is also more suited than some other modeling approaches for evaluating the impacts of SO_2, NO_X, VOC and PM emissions as it has a more robust chemistry mechanism. The CAMx PM Source Apportionment Technology (PSAT) modeling was conducted for those BART-eligible sources that have large SO_2 emissions.[50] In 2006/2007, the TCEQ developed a modeling protocol and analysis using CAMx with the same Plume in Grid and PSAT techniques to evaluate visibility impacts from non-EGU BART sources, as well as to evaluate VOC and PM impacts from all BART-eligible sources to inform the 2009 Texas Regional Haze SIP.[51] [52] This modeling protocol was reviewed by the TCEQ, EPA and FLM representatives specialized in air quality analyses and BART prior to performing the analysis and submission of their regional haze SIP. Our subject-to-BART screening modeling for EGU-sources using CAMx is consistent with the protocol developed and utilized by Texas in their regional haze SIP. We are using more recent model versions with updated science in our analysis.

Consistent with the BART guidelines and our CALPUFF modeling, for the selected BART-eligible sources we used the maximum actual 24-hr emission rates for NO_X and SO_2 from the 2000–2004 baseline period from EPA's Air Markets Program Data[53] and modeled these emission rates as constant emission rates for the entire modeled year. For some of the modeled BART-eligible sources, evaluation of baseline emissions revealed evidence of installation of NO_X control technology during the baseline period. For those sources the maximum emission rate was identified from the post-control portion of the baseline period. Because daily emissions are not available for PM, the annual average emission rate was doubled to approximate the 24-hr maximum emission rate for PM. A BART-eligible source that is shown not to contribute significantly to visibility impairment at any of the Class I areas using CAMx modeling may be excluded from further steps in the BART process. The maximum modeled impact for each source (calculated based on annual average natural background conditions) was compared to the 0.5 dv contribution threshold. See the BART Screening TSD for additional details on the CAMx modeling performed and the model inputs used. The table below summarizes the results of the CAMx screening analysis. As shown in the table below, all sources analyzed with CAMx modeling had impacts greater than 0.5 dv at one or more Class I areas. The most impacted Class I areas based on these results are Wichita Mountains National Wildlife Refuge in Oklahoma (WIMO), Caney Creek Wilderness Area in Arkansas (CACR), and Salt Creek Wilderness Area in New Mexico (SACR). CAMx modeled impacts at single locations for these sources (maximum impact day) ranged from 0.845 dv to 10.498 dv.

[48] *http://ampd.epa.gov/ampd/.*

[49] When we use the term "gas," we mean "pipeline quality natural gas."

[50] CAMx results were also obtained and add to our basis of information for coal-fired facilities that have CALPUFF results.

[51] See TX RH SIP Appendix 9–5, "Screening Analysis of Potential BART-Eligible Sources in Texas"; Revised Draft Final Modeling Protocol Screening Analysis of Potentially BART-Eligible Sources in Texas, Environ Sept. 27, 2006; and Guidance for the Application of the CAMx Hybrid Photochemical Grid Model to Assess Visibility Impacts of Texas BART Sources at Class I Areas, Environ December 13, 2007 all available in the docket for this action.

[52] We approved Texas' subject-to-BART analysis for non-EGU sources which relied on this CAMx modeling in our January 5, 2016 rulemaking (81 FR 296).

[53] *http://ampd.epa.gov/ampd/.*

TABLE 5—CAMX BART SCREENING SOURCE ANALYSIS RESULTS

BART-eligible source	Units	Most impacted Class I area	Maximum delta-dv	Less than 0.5 dv?	Number of modeled days over 0.5 dv [2]	Number of modeled days over 1.0 dv [2]
Big Brown	1 & 2	WIMO	4.017	No	65	33
Coleto Creek	1	WIMO	0.845	No	9	0
Fayette Power	1 & 2	CACR	1.894	No	26	9
Harrington	061B & 062B	SACR	5.288	No	13	5
Martin Lake	1, 2, & 3	CACR	6.651	No	141	99
Monticello	1, 2, & 3	CACR	10.498	No	152	111
Calaveras	J T Deely 1 & 2, OW Sommers 1 & 2.	WIMO	1.513	No	47	6
W A Parish	WAP4, WAP5 & WAP6	CACR	3.177	No	54	22
Welsh [1]	1 & 2	CACR	4.576	No	92	39

[1] Welsh unit 2 has recently shutdown. We note that baseline impacts from unit 1 alone are 2.343 dv at Caney Creek.
[2] Number of days over 0.5 or 1.0 dv at the most impacted Class I area.

5. Summary of Sources that are Subject to BART

Based on the four methodologies described above, the BART-eligible sources in the table below have been determined to cause or contribute to visibility impairment at a nearby Class I area, and we therefore propose to find the sources are subject-to-BART. They are subject to review for visibility impairing pollutants other than NO_X.[54] Foremost, they are subject to SO_2 BART, the visibility impairing pollutant that is the main contributor to the regional haze problem at Class I areas in Texas and neighboring states. The sources are also subject to review for source-specific BART requirements for PM.

TABLE 6—SUMMARY: SOURCES THAT ARE SUBJECT-TO-BART

Facility	Units
Big Brown	1 & 2.
Coleto Creek	1.
Fayette Power	1 & 2.
Harrington	061B & 062B.
Martin Lake	1, 2 & 3.
Monticello	1, 2 & 3.
Calaveras	J T Deely 1 & 2, O W Sommers 1 & 2.
W A Parish	WAP4, WAP5 & WAP6.
Welsh	1 & 2*.
Stryker	ST2.
Graham	2.
Wilkes	1, 2 & 3.
Newman	2, 3 & 4.

* Welsh Unit 2 retired in April, 2016.

C. Our BART Five Factor Analyses

The purpose of the BART analysis is to identify and evaluate the best system of continuous emission reduction based on the BART Guidelines.[55] In determining BART, a state, or EPA when promulgating a FIP, must consider the five statutory factors in section 169A of the CAA: (1) The costs of compliance; (2) the energy and nonair quality environmental impacts of compliance; (3) any existing pollution control technology in use at the source; (4) the remaining useful life of the source; and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. See also 40 CFR 51.308(e)(1)(ii)(A). This is commonly referred to as the ''BART five factor analysis.'' The BART Guidelines break the analyses of these requirements down into five steps:[56]

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.

The following sections treat these steps individually for SO_2. We are combining these steps into one section in our assessment of PM BART that follows the SO_2 sections.

1. Steps 1 and 2: Technically Feasible SO_2 Retrofit Controls

The BART Guidelines state that in identifying all available retrofit control options,

> [Y]ou must identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. It is not necessary to list all permutations of available control levels that exist for a given technology—the list is complete if it includes the maximum level of control each technology is capable of achieving.[57]

Adhering to this, we will identify a reasonable set of SO_2 control options, including those that cover the maximum level of control each technology is capable of achieving. In the course of that task, we will note whether any of these technologies are technically infeasible.

The subject-to-BART units identified in Table 6 can be organized into four broad categories, based on their fuel type and the potential types of SO_2 controls that could be retrofitted: (1) Coal-fired EGUs with no SO_2 scrubber, (2) coal-fired EGUs with underperforming SO_2 scrubbers, (3) gas-fired EGUs that do not burn oil, and (4) gas-fired EGUs that occasionally burn fuel oil. This classification is represented below:

[54] The NO_X BART requirement for these EGU sources is not addressed by source-specific limits in this proposal. According to our proposal, participation in CSAPR, in its updated form, would serve as a BART alternative, dispensing with the need for source-specific BART determinations and requirements for NO_X.

[55] See July 6, 2005 BART Guidelines, 40 CFR part 51, Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations.

[56] 70 FR 39104, 39164 (July 6, 2005) [40 CFR part 51, App. Y].

[57] 70 FR at 39164, fn 12 [40 CFR part 51, App. Y]

TABLE 7—SUBJECT TO BART FUEL TYPES AND POTENTIAL SO_2 BART CONTROLS

Facility	Unit	Coal no scrubber	Coal underperforming scrubber	Gas no oil	Gas burns oil
Big Brown (Luminant)	1	X			
Big Brown (Luminant)	2	X			
Coleto Creek (Engie)	1	X			
Fayette (LCRA) *	1				
Fayette (LCRA) *	2				
Graham (Luminant)	2				X
Harrington Station (Xcel)	061B	X			
Harrington Station (Xcel)	062B	X			
J T Deely (CPS Energy)	1	X			
J T Deely (CPS Energy)	2	X			
Martin Lake (Luminant)	1		X		
Martin Lake (Luminant)	2		X		
Martin Lake (Luminant)	3		X		
Monticello (Luminant)	1	X			
Monticello (Luminant)	2	X			
Monticello (Luminant)	3		X		
Newman (El Paso Electric)	2				X
Newman (El Paso Electric)	3				X
Newman (El Paso Electric)	4			X	
O W Sommers (CPS Energy)	1				X
O W Sommers (CPS Energy)	2				X
Stryker Creek (Luminant)	ST2				X
W A Parish (NRG)	WAP4			X	
W A Parish (NRG)	WAP5	X			
W A Parish (NRG)	WAP6	X			
Welsh Power Plant (AEP)	1	X			
Wilkes Power Plant (AEP)	1				X
Wilkes Power Plant (AEP)	2			X	
Wilkes Power Plant (AEP)	3			X	

* The Fayette units have high performing wet Flue Gas Desulfurization scrubbers in place.

For the coal-fired EGUs without an existing scrubber, we have identified four potential control technologies: (1) Coal pretreatment, (2) Dry Sorbent Injection (DSI), (3) Spray Dryer Absorber (SDA), and (4) wet Flue Gas Desulfurization (FGD.) For the coal-fired EGUs with an existing underperforming scrubber we will examine whether that scrubber can be upgraded.

Gas-fired EGUs that do not burn oil have inherently very low SO_2 emissions and there are no known SO_2 controls that can be evaluated.

For gas-fired units that occasionally burn fuel oil, we will follow the BART Guidelines recommendations for oil-fired units: ''For oil-fired units, regardless of size, you should evaluate limiting the sulfur content of the fuel oil burned to 1 percent or less by weight.'' [58] In addition, we will also evaluate the potential for post combustion SO_2 controls for these units.

a. Identification of Technically Feasible SO_2 Retrofit Control Technologies for Coal-Fired Units

Available SO_2 control technologies for coal-fired EGUs consist of either pretreating the coal in order to improve its qualities, or treating the flue gas through the installation of either DSI or some type of scrubbing technology.

Coal Pretreatment

Coal pretreatment, or coal upgrading, has the potential to reduce emissions by reducing the amount of coal that must be burned in order to result in the same heat input to the boiler. Coal pretreatment broadly falls into two categories: coal washing and coal drying.

Coal washing is often described as preparation (for particular markets) or cleaning (by reducing the amount of mineral matter and/or sulphur in the product coal).[59] Washing operations are carried out mainly on bituminous and anthracitic coals, as the characteristics of subbituminous coals and lignite (brown coals) do not lend themselves to separation of mineral matter by this means, except in a few cases.[60] Coal is mechanically sized, then various washing techniques are employed, depending on the particle size, type of coal, and the desired level of preparation.[61] Following the coal washing, the coal is dewatered, and the waste streams are disposed.

Coal washing takes place offsite at large dedicated coal washing facilities, typically located near where the coal is mined. In addition, coal washing carries with it a number of problems:

• Coal washing is not typically performed on the types of coals used in the power plants under consideration, Powder River Basin (PRB) subbituminous and Texas lignites.

[58] 70 FR 39171 (July 6, 2005) [40 CFR 51, App. Y].

[59] Couch, G.R., ''Coal Upgrading to Reduce CO_2 emissions,'' CCC/67, October 2002, IEA Clean Coal Centre.

[60] Ibid.

[61] Various coal washing techniques are treated in detail in Chapter 4 of *Meeting Projected Coal Production Demands In The USA, Upstream Issues, Challenges, and Strategies,* The Virginia Center for Coal and Energy Research, Virginia Polytechnic Institute and State University, contracted for by the National Commission on Energy Policy, 2008.

• Because coal washing is not typically conducted onsite of the power plant, it is viewed as a consideration in the selection of the coal, and not as an air pollution control.

• Coal washing poses significant energy and non-air quality considerations under section 51.308(e)(1)(ii)(A). For instance, it results in the use of large quantities of water,[62] and coal washing slurries are typically stored in impoundments, which can, and have, leaked.[63]

Because of these issues, we do not consider coal washing as a part of our reasonable set of options for analysis as BART SO_2 control technology.

In general, coal drying consists of reducing the moisture content of lower rank coals, thereby improving the heating value of the coal and so reducing the amount of coal that has to be combusted to achieve the same power, thus improving the efficiency of the boiler. In the process, certain pollutants are reduced as a result of (1) mechanical separation of mineralized sulfur (*e.g.,* and iron pyrite) and rocks, and (2) the unit burning less coal to make the same amount of power.

Coal drying can be performed onsite and so can be considered a potential BART control. Great River Energy has developed a patented process which is being successfully utilized at the Coal Creek facility and is potentially available for installation at other facilities.[64] This process utilizes excess waste heat to run trains of moving fluidized bed dryers. The process offers a number of co-benefits, such as general savings due to lower coal usage (*e.g.,* coal cost, ash disposal), less power required to run mills and ID fans, and lower maintenance on coal handling equipment air preheaters, etc.

Although we view this new patented technology for coal drying onsite as a promising path in the near future for generally improving boiler efficiency and obtaining some reduction in SO_2, its analysis presents a number of difficulties. For instance, the degree of reduction in SO_2 is dependent on a number of factors. These include (1) the quality and quantity of the waste heat available at the unit, (2) the type of coal being dried (amount of bound sulfur, *i.e.,* pyrites, moisture content), and (3) the design of the boiler (*e.g.,* limits to steam temperatures, which can decrease due to the reduced flue gas flow through the convective pass of the boiler). We cannot assess many of these site-specific issues and we believe that requesting that the facilities in question do so would require detailed engineering analysis and extend our review time greatly. As a result of these issues, we do not further assess coal drying as part of our reasonable set of options for BART analysis. We expect that this technology may have matured enough such that it can be better assessed for the second planning period.

DSI

DSI is performed by injecting a dry reagent into the hot flue gas, which chemically reacts with SO_2 and other gases to form a solid product that is subsequently captured by the particulate control device. A blower delivers the sorbent from its storage silos through piping directly to the flue gas ducting via injection lances. The most commonly used sorbent is trona, a naturally occurring mineral primarily mined from the Green River Formation in Wyoming. Trona can also be processed into sodium bicarbonate, which is more reactive with SO_2 than trona, but more expensive. Hydrated lime is another potential sorbent but it is less frequently used and little data are available regarding its potential performance and cost. In general, trona is considered the most cost-effective of the sorbents for SO_2 removal. There are many examples of DSI being used on coal-fired EGUs to control SO_2. However, DSI may not be technically feasible at every coal-fired EGU. For instance, Luminant states in its response to one of our Section 114(a) letters regarding its Big Brown and Monticello units: [65]

Luminant commissioned the study of dry sorbent injection (''DSI'') at these units in 2011. These studies determined that a very high feed rate (in the range of 20–30%) was required to achieve modest SO_2 removal. Further, it was determined that other economic and operational factors make the use of DSI infeasible. For example, sorbent build-up was determined to cause degraded performance of the control equipment over time, as well as significant, repeat down time on a regular basis (*i.e.,* every few days) to remove the buildup. In addition to the high cost of the sorbent required, the disposal and transport of the used sorbent (a Texas Class 1 waste) would result in significant additional cost. Thus, the use of DSI was determined infeasible from both an operational and economic point of view, and further evaluation has been discontinued.

As a consequence of this statement, which is discussed more fully in the CBI material Luminant has submitted and in our TSD, we have concluded that DSI is not a feasible alternative for the Big Brown and Monticello facilities. For all unscrubbed, coal-fired BART-subject units other than the Big Brown and Monticello facilities, although individual installations may present technical difficulties or poor performance due to the suboptimization of one or more of the above factors, we believe that DSI is technically feasible and should be considered as a potential BART control.

SO_2 Scrubbing Systems

In contrast to DSI, SO_2 scrubbing techniques utilize a large dedicated vessel in which the chemical reaction between the sorbent and SO_2 takes place either completely or in large part. Also in contrast to DSI systems, SO_2 scrubbers add water to the sorbent when introduced to the flue gas. The two predominant types of SO_2 scrubbing employed at coal-fired EGUs are wet FGD, and Spray Dry Absorber (SDA). More recently, Circulating Dry Scrubbers (CDS) have been introduced. The EIA reports the following types of flue gas desulfurization systems as being operational in the U.S. for 2015:

TABLE 8—EIA REPORTED DESULFURIZATION SYSTEMS IN 2015

Type	Number of installations
Wet spray tower scrubber	296
Spray dryer absorber	269
Circulating dry scrubber	50
Packed tower wet scrubber	6
Venturi wet scrubber	48
Jet bubbling reactor	31
Tray tower wet scrubber	42
Mechanically aided wet scrubber.	4
DSI	106
Other	1
Unspecified	1
Total	854

Excluding the DSI installations, EIA lists 748 SO_2 scrubber installations in operation in 2015. Of these, 296 are listed as being spray type wet scrubbers, with an additional 42 listed as being

[62] ''Water requirements for coal washing are quite variable, with estimates of roughly 20 to 40 gallons per ton of coal washed (1 to 2 gal per MMBtu) (Gleick, 1994; Lancet, 1993).'' Energy Demands on Water Resources, Report to Congress on the Interdependency of Energy and Water, U.S. Department Of Energy, December 2006.

[63] Committee on Coal Waste Impoundments, Committee on Earth Resources, Board on Earth Sciences and Resources, Division on Earth and Life Studies; *Coal Waste Impoundments, Risks, Responses, and Alternatives;* National Research Council; National Academy Press, 2002.

[64] DryFining™ is the company's name for the process. It is described here: *http://www.powermag.com/improve-plant-efficiency-and-reduce-co2-emissions-when-firing-high-moisture-coals/.*

[65] Luminant's 6/17/14 response to EPA's 5/20/14 Section 114(a) request for information relating to the Big Brown, Martin Lake, Monticello, and Sandow generating stations.

tray type wet scrubbers.[66] An additional 269 are listed as being spray dry absorber types. Consequently, spray type or tray type wet scrubbers (wet FGD) account for approximately 45% of all scrubber systems, and spray dry scrubbers (SDA) account for approximately 36% of all scrubber systems that were operational in the U.S. in 2015.

We consider some of the other scrubber system types (*e.g.,* venturi and packed wet scrubber types) to be older, outdated technologies (that are not existing controls or factor into considerations regarding existing controls) and therefore will not be considered in our BART analysis. Jet bubbling reactors and circulating dry scrubbers are relatively new technologies, with limited installations, and little information is available with which to characterize them or their suitability as a retrofit control option. Therefore, they too will not be further considered as part of our reasonable set of options for analysis for BART controls.

In summary, wet FGD and SDA installations account for approximately 81% of all scrubber installations in the U.S. and as such constitute a reasonable set of SO_2 scrubber control options. The vast majority of the wet FGD and SDA installations utilize limestone and lime, respectively as reagents. In addition, these technologies cover the maximum level of SO_2 control available. As described above, these controls are in wide use and have been retrofitted to a variety of boiler types and plant configurations. We therefore see no technical infeasibility issues and believe that limestone wet FGD and lime SDA should be considered as potential BART controls for all of the unscrubbed coal-fired BART-eligible units.

b. Identification of Technically Feasible SO_2 Retrofit Control Technologies for Gas-Fired Units that Burn Oil

Reduction in Fuel Oil Sulfur

A number of the units we proposed in Table 6 as being subject to BART primarily fire gas, but have occasionally fired fuel oil in the past as reported by the EIA databases: EIA–767, EIA–906/920, and EIA–923,[67] which indicate the historic quantities of fuel oil burned and the type and sulfur content of that fuel oil. These units are identified below in Table 9:

TABLE 9—GAS UNITS THAT OCCASIONALLY BURN OIL AND ARE SUBJECT TO BART

Facility	Unit(s)	Gas turbine	Steam turbine
Graham (Luminant)	2		X
Newman (El Paso Electric)	2, 3		X
O W Sommers (CPS Energy)	1, 2		X
Stryker Creek (Luminant)	ST2		X
Wilkes Power Plant (AEP)	1		X

The BART Guidelines advise that for oil-fired units, regardless of size, limits on fuel oil sulfur content should be considered in the BART evaluation.[68] All of the subject units are limited by permit to burning oil with a sulfur content of no more than 0.7% sulfur by weight.[69] In analyzing the technical feasibility under BART of these facilities burning fuel oils of sulfur contents lower than historically burned, we investigated two issues: (1) Is lower sulfur fuel oil available and what is its cost, and (2) are there any technical issues in burning a lower sulfur fuel oil that could add to the cost of that oil? All of the units have either burned Distillate Fuel Oil (DFO) or have switched between DFO and Residual Fuel Oil (RFO), thus demonstrating the ability to burn DFOs of the type under consideration for SO_2 BART. We therefore conclude that lower sulfur DFOs are a technically feasible retrofit control option under BART. Lower sulfur DFOs carry no capital costs. Any cost increases relate to purchase price differences.

SO_2 Scrubber Feasibility for Gas/Oil-Fired Boilers

We are aware of instances in which FGDs of various types have been installed or otherwise deemed feasible on a boiler that burns oil.[70] Consequently, we will consider the installation of various types of scrubbers to be technically feasible.

c. Identification of Technically Feasible SO_2 Control Technologies for Scrubber Upgrades

In our recent Texas-Oklahoma FIP,[71] we presented a great deal of information that concluded that the existing scrubbers for a number of facilities could be very cost-effectively upgraded.[72] That information is included in this proposal.[73] It contains a comprehensive survey of available literature concerning the kinds of upgrades that have been performed by industry on scrubber systems similar to the ones installed on the units included in this proposal. We then reviewed all of the information we had at our disposal regarding the status of the existing scrubbers for each unit, including any upgrades the facility may have already installed. We finished by calculating the cost-effectiveness of scrubber upgrades, using the facility's own information, obtained as a result of our Section 114 collection efforts. The companies that supplied this information have asserted a Confidential Business Information (CBI) claim for much of it, as provided in 40 CFR 2.203(b). We therefore redacted any CBI information we utilize in our analyses, or otherwise disguised it so that it cannot be traced back to its specific source. Of the facilities we evaluated for scrubber upgrades in that action, Martin Lake Units 1, 2, and 3; and Monticello Unit 3 are subject to BART and are thus a part of this proposal.

[66] Trays are often employed in spray type wet scrubbers and EIA lists some of the wet spray tower systems as secondarily including trays.

[67] EIA-767: *http://www.eia.gov/electricity/data/eia767/*. EIA–906/920 and EIA–923: *http://www.eia.gov/electricity/data/eia923/*.

[68] 70 FR at 39171.

[69] In addition, the Newman units 2 and 3 are restricted to burning fuel oil for no more than 10% of their annual operating time.

[70] Crespi, M. ''Design of the FLOWPAC WFGD System for the Amager Power Plant.'' Power-Gen FGD Operating Experience, November 29, 2006, Orlando, FL.

Babcock and Wilcox. ''Wet Flue Gas Desulfurization (FGD) Systems Advanced Multi-Pollutant Control Technology.'' See Page 4: ''We have also provided systems for heavy oil and Orimulsion fuels.''

DePriest, W; Gaikwad, R. ''Economics of Lime and Limestone for Control of Sulfur Dioxide.'' See page 7: ''A CFB unit, in Austria, is on a 275 MW size oil-fired boiler burning 1.0–2.0% sulfur oil.''

[71] 81 FR 321.

[72] See information presented in Sections 6 and 7 of the Cost TSD.

[73] That information is included in our BART FIP TSD, Appendix B.

2. Step 3: Evaluation of SO_2 Control Effectiveness

In the following subsections, we evaluate the control levels each technically feasible technology is capable of achieving for the coal and gas units. In so doing, we consider the maximum level of control each technology is capable of delivering based on a 30 Boiler Operating Day (BOD) period. As the BART Guidelines direct, ''[y]ou should consider a boiler operating day to be any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit.'' [74] To calculate a 30-day rolling average based on BOD, the average of the last 30 ''boiler operating days'' is used. In other words, days are skipped when the unit is down, as for maintenance. In effect, this provides a margin of safety by eliminating spikes that occur at the beginning and end of outages.

a. Evaluation of SO_2 Control Effectiveness for Coal Fired Units

Control Effectiveness of DSI

We lack the site-specific information, which we believe requires an individual performance test, in order to be able to accurately determine the maximum DSI SO_2 removal efficiency for the individual units listed in Table 7. We are aware that a number of the subject-to-BART coal-fired units have conducted such testing. However, although we have examined that testing, most of the facilities have claimed it as CBI and requested protection from public disclosure as provided by 40 CFR part 2.

However, we nevertheless must evaluate DSI as a viable, proven method of SO_2 control. We must do the same for SO_2 scrubbing, and in so doing, compare the visibility benefits and costs of each technology in order to inform our proposed BART determinations. We therefore propose the following methodology:

- We will evaluate each unit at its maximum recommended DSI performance level, according to the IPM DSI documentation,[75] assuming milled trona: 80% SO_2 removal for an ESP installation and 90% SO_2 removal for a baghouse installation. This level of control is within the range that can be achieved by SO_2 scrubbers, and thus allows a better comparison of the costs of DSI and scrubbers.
- However, (1) we do not know whether a given unit is actually capable of achieving these control levels and (2) we believe it is useful to evaluate lesser levels of DSI control (and correspondingly lower costs). We therefore also evaluate all the units at a DSI SO_2 control level of 50%, which we believe is likely achievable for most units.
- We invite comments on whether particular units have performed DSI testing and have concluded they cannot achieve a SO_2 reduction between 50% and 80/90%. Any data to support such a conclusion should be submitted along with those comments.

Control Effectiveness of Wet FGD and SDA

We have assumed a wet FGD level of control to be a maximum of 98% not to go below 0.04 lbs/MMBtu, in which case, we assume the percentage of control equal to 0.04 lbs/MMBtu. As we discuss later in this proposal, we will conduct our wet FGD control cost analysis using the wet FGD cost algorithms, as employed in version 5.13 of our IPM model.[76] The IPM wet FGD Documentation states: ''The least squares curve fit of the data was defined as a ''typical'' wet FGD retrofit for removal of 98% of the inlet sulfur. It should be noted that the lowest available SO_2 emission guarantees, from the original equipment manufacturers of wet FGD systems, are 0.04 lb/MMBtu.'' As we established in our Oklahoma FIP,[77] this level of control is achievable with wet FGD. This level of control was also employed in our recent Texas-Oklahoma FIP.[78] We received a comment challenging this level of control and we responded to that comment in our final action on our Texas-Oklahoma FIP and incorporate that response in this proposed action.[79] We continue to conclude that our proposed level of control for wet FGD is reasonable.

As with our Oklahoma FIP, we have assumed a SDA level of control equal to 95%, unless that level of control would fall below an outlet SO_2 level of 0.06 lb/MMBtu, in which case, we assume the percentage of control equal to 0.06 lbs/MMBtu. See our response to comments in our previous Oklahoma FIP.[80] In that FIP, we finalized the same emission limit of 0.06 lbs/MMBtu on a 30 BOD average for 6 coal-fired EGUs. We justified those limits based on the same SDA technology, using a combination of industry publications and real world monitoring data. Much of that information is summarized in our response to a comment to that action [81] and in our TSD. We continue to conclude that our proposed level of control for SDA is reasonable.

b. Evaluation of SO_2 Control Effectiveness for Gas Fired Units

The control effectiveness of switching from a higher sulfur fuel oil to a lower sulfur fuel oil lies in the reduction in sulfur emissions. The emissions reduction depends on the percentage reduction from the sulfur contents of the fuel oil that forms the SO_2 baseline to the replacement fuel oil. Ultimately, the highest level of control would result from a switch from the highest percentage sulfur the units are permitted to burn, 0.7% to the lowest DFO available, ultra-low sulfur diesel, which has a sulfur content of 0.0015%. This would equate to a control effectiveness of 99.8%. Lesser levels of controls are also possible. We will evaluate a range of control effectiveness in switching to lower sulfur fuel oils in the next section.

[74] 70 FR 39103, 39172 (July 6, 2005), [40 CFR part 51, App. Y].

[75] IPM Model—Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2 Control Cost Development Methodology, Final March 2013, Project 12847–002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy, p. 7.

[76] IPM Model—Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2 Control Cost Development Methodology, Final March 2013, Project 12847–002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy. Documentation for v.5.13: Chapter 5: Emission Control Technologies, Attachment 5–5: DSI Cost Methodology, downloaded *https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-5_dsi_cost_methodology.pdf.*

IPM Model—Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, Final March 2013, Project 12847–002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy. Documentation for v. 5.13: Chapter 5: Emission Control Technologies, Attachment 5–2: SDA FGD Cost Methodology, downloaded from *https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-2_sda_fgd_cost_methodology_3.pdf.*

IPM Model—Updates to Cost and Performance for APC Technologies, wet FGD Cost Development Methodology, Final March 2013, Project 12847–002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy. Documentation for v.5.13: Chapter 5: Emission Control Technologies, Attachment 5–1: Wet FGD Cost Methodology, downloaded from *https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-1_wet_fgd_cost_methodology.pdf.*

[77] As discussed previously in our TSD for that action, control efficiencies reasonably achievable by dry scrubbing and wet scrubbing were determined to be 95% and 98% respectively. 76 FR 81742); *Oklahoma* v. *EPA*, 723 F.3d 1201 (July 19, 2013), cert. denied (U.S. May 27, 2014).

[78] 81 FR 321.

[79] That information is included in our BART FIP TSD, Appendix A.

[80] 76 FR 81728.

[81] Response to Technical Comments for Sections E through H of the **Federal Register** Notice for the Oklahoma Regional Haze and Visibility Transport Federal Implementation Plan, Docket No. EPA–R06–OAR–2010–0190, 12/13/2011. See comment and response beginning on page 91.

Because we are unaware of any scrubber installations on oil fired units in the U.S., we have no information on their control effectiveness. However, we see no technical reason why the control effectiveness of FGDs installed on gas-fired units that occasionally burn fuel oil should not be equal to that of FGDs installed on coal-fired units.

3. Step 4: Evaluate Impacts and Document the Results for SO_2

The BART Guidelines offers the following with regard to how Step 4 should be conducted: [82]

After you identify the available and technically feasible control technology options, you are expected to conduct the following analyses when you make a BART determination:

Impact analysis part 1: Costs of compliance,
Impact analysis part 2: Energy impacts, and
Impact analysis part 3: Non-air quality environmental impacts.
Impact analysis part 4: Remaining useful life.

We evaluate the cost of compliance on a unit-by unit basis, because control cost analysis depends on specific factors that can vary from unit to unit. However, we generally evaluate the energy impacts, non-air quality impacts, and the remaining useful life for all the units in question together because in this instance there are no appreciable differences in these factors from unit to unit.[83]

In developing our cost estimates for the units in Table 7, we rely on the methods and principles contained within the EPA Air Pollution Control Cost Manual (the Control Cost Manual, or Manual).[84] We proceed in our SO_2 costing analyses by examining the current SO_2 emissions and the level of SO_2 control, if any, for each of the units listed in Table 7. For the coal units without any SO_2 control, we calculate the cost of installing DSI, a SDA scrubber, and a wet FGD scrubber. For the gas units that burn oil, we evaluate the cost of switching to lower sulfur fuel oils and installing scrubbers.

In order to estimate the costs for DSI, SDA scrubbers, and wet FGD scrubbers, we programmed the DSI, SDA and wet FGD cost algorithms, as employed in version 5.13 of our IPM model, referenced above, into three spreadsheets. These cost algorithms calculate the Total Project Cost (TPC), Fixed Operating and Maintenance (Fixed O&M) costs, and Variable Operating and Maintenance (Variable O&M) costs. We then performed DSI, SDA and wet FGD cost calculations for each unit listed in Table 7 that did not already have SO_2 control.[85] These cost models were based on costs escalated to 2012 dollars.[86] Because the IPM 5–13 cost algorithms were calculated in 2012 dollars, we have escalated them to 2016, using the annual Chemical Engineering Plant Cost Indices (CEPCI).

a. Impact Analysis Part 1: Cost of Compliance for DSI, SDA, and Wet FGD

As we discuss above and in our Cost TSD, we evaluated each unit at its maximum recommended level of control, considering the type of SO_2 control device. Below, we present a summary of our DSI, SDA, and wet FGD cost analysis: [87]

TABLE 10—SUMMARY OF DSI, SDA, AND WET FGD COST ANALYSIS

Facility	Unit	Control	Control level (%)	SO_2 reduction (tpy)	2016 Annualized cost	2016 Cost effectiveness ($/ton)	2016 Incremental cost-effectiveness ($/ton)
Big Brown	1	DSI	50	14,448	$29,468,587	$2,040	
		DSI	90	26,006	72,131,749	2,774	$3,691
		SDA	95	27,453	35,297,532	1,286	−25,456
		Wet FGD	98	28,320	33,673,102	1,189	−1,874
	2	DSI	50	15,320	29,342,350	1,915	
		DSI	90	27,576	71,322,593	2,586	3,425
		SDA	95	29,108	35,359,239	1,215	−23,475
		Wet FGD	97.9	29,998	33,817,952	1,127	−1,732
Monticello	1	DSI	50	4,787	11,408,872	2,383	
		DSI	90	8,617	25,409,128	2,949	3,655
		SDA	95	9,095	24,294,319	2,671	−2,332
		Wet FGD	97	9,286	25,236,699	2,718	4,934
	2	DSI	50	4,129	9,742,648	2,360	
		DSI	90	7,431	21,418,734	2,882	3,536
		SDA	95	7,844	23,126,113	2,948	4,134
		Wet FGD	96.8	7,995	24,233,133	3,031	7,331
Coleto Creek	1	DSI	50	7,376	16,246,169	2,203	
		DSI	90	13,277	34,841,379	2,624	3,151
		SDA	92.4	13,632	29,445,018	2,160	−15,201
		Wet FGD	94.9	14,005	29,786,106	2,127	914
Harrington	061B	DSI	50	2,477	9,187,608	3,710	
		DSI	80	3,962	16,073,779	4,057	4,637
		SDA	90.2	4,466	17,455,679	3,909	2,742
	062B	DSI	50	2,455	6,524,937	2,658	
		DSI	* 88.9	4,364	11,981,111	2,746	2,858
		SDA	88.9	4,364	18,240,127	4,180	N/A
J T Deely	1	DSI	50	3,072	8,854,319	2,883	

[82] 70 FR 39166.

[83] To the extent these factors inform the cost of controls, consistent with the BART Guidelines, they do inform our considerations on a unit-by-unit basis.

[84] EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B–02–001, January 2002 available at *http://www.epa.gov/ttncatc1/dir1/c_allchs.pdf*.

[85] These spreadsheets are entitled, ''DSI Cost IPM 5–13 TX BART.xlsx,'' ''SDA Cost IPM 5–13 TX BART.xlsx,'' and ''Wet FGD Cost IPM 5–13 TX BART.xlsx,'' and are located in our Docket.

[86] Ibid., p.1: ''The data was converted to 2012 dollars based on the Chemical Engineering Plant Index (CEPI) data.''

[87] In this table, the capital cost is the total cost of constructing the facility. The annualized cost is the sum of the annualized capital cost and the annualized operational cost. See our Cost TSD for more information on how these costs were calculated.

TABLE 10—SUMMARY OF DSI, SDA, AND WET FGD COST ANALYSIS—Continued

Facility	Unit	Control	Control level (%)	SO_2 reduction (tpy)	2016 Annualized cost	2016 Cost effectiveness ($/ton)	2016 Incremental cost-effectiveness ($/ton)
		DSI	90	5,529	18,071,878	3,269	3,752
		SDA	91.3	5,609	21,689,526	3,867	45,221
		Wet FGD	94.2	5,787	22,555,395	3,898	4,864
	2	DSI	50	3,222	9,865,798	3,062	
		DSI	90	5,800	20,229,233	3,488	4,020
		SDA	91.3	5,884	21,812,518	3,707	18,849
		Wet FGD	94.2	6,070	22,530,901	3,712	3,862
Welsh	1	DSI	50	3,343	8,963,761	3,469	
		DSI	* 87.2	5,832	23,090,408	3,960	5,676
		SDA	87.2	5,832	22,697,048	3,892	N/A
		Wet FGD	91.5	6,116	23,998,161	3,924	4,581
W.A. Parish	5	DSI	50	6,712	15,002,337	2,235	
		DSI	90	12,081	30,865,711	2,555	2,955
		SDA	92.1	12,364	31,195,787	2,523	1,166
		Wet FGD	94.7	12,717	30,735,030	2,417	−1,305
	6	DSI	50	7,525	16,014,988	2,128	
		DSI	90	13,545	33,302,528	2,459	2,872
		SDA	92.1	13,862	32,758,784	2,363	−1,715
		Wet FGD	94.7	14,258	32,215,226	2,259	−1,373

* DSI control level limited to that of SDA.

b. Impact Analysis Part 1: Cost of Compliance for Scrubber Upgrades

In our BART FIP TSD, we analyze those units listed in Table 7 with an existing SO_2 scrubber in order to determine if cost-effective scrubber upgrades are available. Of our subject-to-BART units, Martin Lake Units 1, 2, 3; Monticello Unit 3, and Fayette Units 1 and 2 are currently equipped with wet FGDs. Of these, all but the Fayette units were analyzed for scrubber upgrades in our Texas-Oklahoma FIP. For all but the Fayette units, we propose to adopt the total annualized cost calculations used to make the cost-effectiveness calculations in our Texas-Oklahoma FIP in this action. We acknowledge that these costs could change slightly, due to changes in the costs of various materials and services. However, these costs were calculated in 2013 dollars. Escalating them to 2015 dollars would result in a reduction in cost, which we conservatively do not take into consideration.[88]

In our Texas-Oklahoma FIP action, after responding to comments we revised our proposed cost-effectiveness basis from where all scrubber upgrades were less than $600/ton, to where all scrubber upgrades ranged from between $368/ton to $910/ton.[89] As with our Texas-Oklahoma FIP, we are limited in what information we can include in this section, because we used information that was claimed as CBI. This information was submitted in response to our Section 114(a) requests. The following summary is based on information not claimed as CBI.

- The absorber system had either already been upgraded to perform at an SO_2 removal efficiency of at least 95%, or it could be upgraded to perform at that level using proven equipment and techniques.
- The SO_2 scrubber bypass could be eliminated, and the additional flue gas could be treated by the absorber system with at least a 95% removal efficiency.
- Additional modifications necessary to eliminate the bypass, such as adding fan capacity, upgrading the electrical distribution system, and conversion to a wet stack could be performed using proven equipment and techniques.
- The additional SO_2 emission reductions resulting from the scrubber upgrade are substantial, ranging from 68% to 89% reduction from the current emission levels, and are cost-effective.

We now update these calculations for 2011–2015 data.[90] The revised scrubber upgrade results for Martin Lake Units 1, 2, and 3; and Monticello Unit 3 are presented below in Table 11:

TABLE 11—SUMMARY OF UPDATED SCRUBBER UPGRADE RESULTS

Unit	2011–2015 3-yr avg. SO_2 emissions (eliminate max and min) (tons)	SO_2 emissions at 95% control (tons)	SO_2 emissions reduction due to scrubber upgrade (tons)	SO_2 emission rate at 95% control (lbs/MMBtu)
Monticello 3	8,136	1,180	6,956	0.05
Martin Lake 1	19,040	3,208	15,832	0.12
Martin Lake 2	17,973	3,393	14,580	0.12
Martin Lake 3	16,113	2,591	13,522	0.11
Total SO_2 Removed			50,890	

[88] The CEPCI for 2013 is 567.3 and that for 2015 is 556.3. Therefore, the costs would be multiplied by a factor of 556.8/567.3, which is approximately 0.98.

[89] 81 FR 318.

[90] See Coal vs CEM data 2011–2015.xlsx.

As we note above, we updated the cost-effectiveness for each of these units. Because those calculations depended on information claimed by the companies as CBI we cannot present it here, except to note that in all cases, the cost-effectiveness was $1,156/ton or less. We invite the facilities listed above to make arrangements with us to view our complete updated cost analysis for their units.

The Fayette Units 1 and 2 are currently equipped with high performing wet FGDs. Both units have demonstrated the ability to maintain a SO_2 30 BOD average below 0.04 lbs/MMBtu for years at a time.[91] As we discuss above, we evaluate BART demonstrating that retrofit wet FGDs should be evaluated at 98% control not to go below 0.04 lbs/MMBtu. Because the Fayette units are performing below this level, we propose that no scrubber upgrades are necessary. We propose to find that the Fayette Units 1 and 2 maintain a 30 Boiler Operating Day rolling average SO_2 emission rate of 0.04 lbs/MMBtu based on the actual emissions data we present above. We believe that based on its demonstrated ability to maintain an emission rate below this value on a 30 BOD basis, it can consistently achieve this emission level.

c. Impact Analysis Part 1: Cost of Compliance for Gas Units That Burn Oil

As we noted in Section III.C.1.b, a number of the units we proposed in Table 9 as being subject to BART primarily fire gas, but have occasionally fired fuel oil in the past as reported by the EIA. These units are limited by their permits to burning oil with a sulfur content of no more than 0.7% sulfur by weight. We proposed to consider both a reduction in fuel oil sulfur and SO_2 scrubbers as potential BART controls. Below we consider the cost of these potential controls.

Reduction in Fuel Oil Sulfur

In order to determine the cost of these facilities switching to lower sulfur content fuel oils, we sent the Graham, Newman, Stryker Creek, and the Wilkes facilities Section 114 letters requesting certain information.[92] We received very limited information in response to one of our questions concerning the present cost of the historic fuel oil burned, and the cost of various lower sulfur replacement fuel oils. Because of this, we were unable to compile facility-specific information on the cost of switching to lower sulfur fuel oils. Consequently, we considered the best available information by consulting more general information from the EIA, which reports the prices for various refinery petroleum products on a monthly and annual basis. Below is a summary of various distillate and residual fuel oil products for 2001 to 2015, averaged across the U.S.[93]

TABLE 12—SELECTED EIA REPORTED ANNUAL REFINER PETROLEUM PRICES

Date	West Texas intermediate crude oil—Cushing Oklahoma ($/bbl)	U.S. no. 2 diesel wholesale/resale price by refiners ($/gallon)	U.S. no. 2 fuel oil wholesale/resale price by refiners ($/gallon)	U.S. no. 4 distillate wholesale/resale price by refiners ($/gallon)
2015	48.66	1.667	1.565	1.215
2014	93.17	2.812	2.741	2.333
2013	97.98	3.028	2.966	2.767
2012	94.05	3.109	3.031	
2011	94.88	3.034	2.907	2.801
2010	79.48	2.214	2.147	
2009	61.95	1.713	1.657	1.561
2008	99.67	2.994	2.745	2.157
2007	72.34	2.203	2.072	1.551
2006	66.05	2.012	1.834	1.395
2005	56.64	1.737	1.623	1.377
2004	41.51	1.187	1.125	1.033
2003	31.08	0.883	0.881	0.793
2002	26.18	0.724	0.694	0.663
2001	25.98	0.784	0.756	0.697
2000	30.38	0.898	0.886	0.778

Lacking facility-specific pricing information, for the purposes of calculating the cost of compliance, we make the following assumptions:

- No. 4 distillate is the type of fuel oil currently available that most closely approximates the types of fuel oil that were historically burned by the facilities. It is available in a range of sulfur up to the facilities' permitted maximum of 0.7% sulfur by weight or 7,000 ppm. We will use the cost of this fuel oil in constructing ''business as usual'' scenarios of the annual cost of fuel oil.
- No. 2 fuel oil is available at approximately 3,000 ppm, which roughly corresponds to the sulfur level present in No. 2 fuel oil prior to our implementation of the Ultra-Low-Sulfur Diesel (ULSD) regulations.[94] We will use the cost of this fuel oil in constructing a ''medium control'' annual cost of fuel oil.
- No. 2 diesel fuel corresponds to ULSD, with a sulfur content of 15 ppm. We will use the cost of this fuel oil in constructing a ''high control'' annual cost of fuel oil.

Having identified a reasonable set of historical and lower sulfur fuel oils, we turned to the matter of establishing SO_2 baselines. We would expect that regardless of the baseline selected, a cost-effectiveness calculation that simply depended on differing fuel oil costs and the resulting reductions in SO_2, would result in the same value. In other words, the cost-effectiveness in $/ton is independent of the SO_2 baseline, since *in this case,* it is calculated on a unit basis—the increased cost in burning a unit of fuel divided by the increased reduction in the resulting

[91] See our BART FIP TSD for graphs of this data.

[92] Copies of these letters and the facilities' responses are in our docket. We inadvertently did not send the O W Sommers a letter.

[93] EIA Refiner Petroleum Product Prices by Sales Type, available here: *http://www.eia.gov/dnav/pet/pet_pri_refoth_dcu_nus_a.htm; http://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm.*

[94] 69 FR 39073: ''Both high sulfur No. 2–D and No. 2 fuel oil must contain no more than 5000 ppm sulfur,131 and currently [as of the date of our final rule, 6/29/04] averages 3000 ppm nationwide.''

SO_2. While the above is true, reported data for these units does not match this expectation. This can be illustrated by examining selected EIA and emissions data for the Graham Unit 2:

TABLE 13—GRAHAM UNIT 2 EXAMPLE DISCORDANCE IN FUEL OIL BURNED AND REPORTED SO_2

Date (month/year)	Quantity fuel oil burned (bbls)	Reported SO_2 for month (tons)	Reported EIA sulfur content (wt %)
Mar-02	9,800	21.614	0.65
Feb-03	8,400	90.389	0.66
Jun-12	18,177	0.064	0.50
Jul-12	5,657	0.07	0.50

As can be seen from the above table, even though the reported sulfur content of the fuel oil in March 2002 and February 2003 was approximately the same, and the quantity burned was fairly close, the reported SO_2 emissions were significantly different. Similarly, although the amount of fuel oil burned in June 2012 was more than three times that burned in July 2012 (at the same sulfur content), the reported SO_2 emissions in June 2012 were less than that in July 2012. Also, although the fuel oil sulfur content in the 2012 examples was only slightly less than that in the 2002/2003 examples, and the amount of fuel oil burned was the same order of magnitude, the resulting reported SO_2 emissions in 2012 were three orders of magnitude less than that in 2002/2003. We conclude that either the values for the EIA fuel quantities, the EIA fuel oil sulfur contents, and/or the reported SO_2 emissions are in error. Further examination of the CAMD emissions data for Graham and Stryker revealed that the data contained a large amount of substitute data for SO_2 emissions and heat input during periods when the units burned fuel oil.

As a consequence of this discordance between the type and amount of fuel oil burned and the reported SO_2 emissions, we cannot rely on historical SO_2 emissions to construct a baseline, because a barrel of fuel oil with a given sulfur content does not result in a consistent reported SO_2 value over time. Instead, we will conduct our cost-effectiveness analysis on the basis of unit values of 1,000 barrels, using the following assumptions:

- Fuel oil costs will be based on the 2015 U.S. average prices as reported in Table 12 for No. 4 distillate at 0.7 wt. % (the permitted maximum for all units) as the current business as usual fuel, No. 2 fuel oil at 0.3 wt. % as the moderate control option, and No. 2 diesel at 0.0015% as the high control option.
- The emission factor for calculating the tons of sulfur emitted by the three fuel oils are taken from AP 42, *Compilation of Air Pollutant Emissions Factors.*[95]

Below is the result of that calculation:

TABLE 14—COST EFFECTIVENESS OF SWITCHING TO LOWER SULFUR FUEL OILS

Level of control	Cost for 1,000 barrels baseline ($/yr)	Tons reduced for 1,000 barrels	Cost effectiveness for 1,000 barrels ($/ton)	Incremental cost-effectiveness ($/ton)
Business as usual (No. 4 distillate $1.215/gal)	$51,030	N/A	N/A	
Moderate control (No. 2 fuel oil $1.565/gal)	65,730	1.26	11,218	
High control (ULSD $1.667/gal)	70,014	2.20	8,627	−2,756

We suspect our price information for ULSD may be high, as the Wilkes facility indicated in its reply to our Section 114 request that its 8/12/16 contract for oil was for ULSD, which had an index price of $1.423/gallon. Assuming this price and retaining the same price for our business as usual No. 4 distillate fuel oil of $1.215/gallon, results in a cost-effectiveness of $3,970/ton—a significant improvement in cost-effectiveness. We invite the affected facilities to provide site-specific information for delivery of ULSD.

Scrubber Retrofits

Elsewhere in our proposal, we conclude that certain types of wet scrubbers were technically feasible as potential control options for gas boilers that occasionally burn oil, similar to the ones under BART review here. Were we to calculate the cost-effectiveness of a wet FGD, similar to those under consideration for the coal units undergoing BART review, we could expect that the capital and operating costs would be on the same order, as displayed in Table 10. It is a straightforward exercise to demonstrate that the installation of such a scrubber on any of the gas-fired units that occasionally burn oil would result in a very high cost-effectiveness value.

For instance, taking the smallest total annualized wet FGD cost in Table 10, corresponding to the Harrington Unit 0161B (approximately the same size as the Graham Unit 2), results in a value of $19,145,500. Assuming a 98% reduction from a baseline equal to the largest annual SO_2 emissions from any of the gas units, 1,287 tons/year (Graham Unit 2, 2001), results in a SO_2 reduction of 1,261 tons/year. The cost-effectiveness is then $15,183/ton, which is very high for a SO_2 scrubber. In addition, the annual SO_2 values for Graham Unit 2 from 2002 to 2015, and the annual SO_2 values for the remaining units, have always been an order of magnitude less than the 2001 Graham Unit 2 value. Although we have not modeled the visibility benefit of

[95] The emission factor (lb/10^3 gal) used is 150 × S, where S = weight % sulfur, taken from AP 42, Fifth Edition, Volume 1, Chapter 1: External Sources, Section 1.3, Fuel Oil Combustion, available here: *https://www3.epa.gov/ttn/chief/ap42/ch01/index.html.* Boilers >100 Million Btu/hr, No. 4 oil fired.

installing SO_2 scrubbers on these units, the visibility benefit from scrubbers is estimated to be slightly less than the amount of benefit estimated from switching to ULSD.[96]

4. Impact Analysis Parts 2, 3, and 4: Energy and Non-air Quality Environmental Impacts, and Remaining Useful Life

Regarding the analysis of energy impacts, the BART Guidelines advise, ''You should examine the energy requirements of the control technology and determine whether the use of that technology results in energy penalties or benefits.'' [97] As discussed above in our cost analyses for DSI, SDA, and wet FGD, our cost model allows for the inclusion or exclusion of the cost of the additional auxiliary power required for the pollution controls we considered to be included in the variable operating costs. We chose to include this additional auxiliary power in all cases. Consequently, we believe that any energy impacts of compliance have been adequately considered in our analyses.

Regarding the analysis of non-air quality environmental impacts, the BART Guidelines advise: [98]

Such environmental impacts include solid or hazardous waste generation and discharges of polluted water from a control device. You should identify any significant or unusual environmental impacts associated with a control alternative that have the potential to affect the selection or elimination of a control alternative. Some control technologies may have potentially significant secondary environmental impacts. Scrubber effluent, for example, may affect water quality and land use. Alternatively, water availability may affect the feasibility and costs of wet scrubbers. Other examples of secondary environmental impacts could include hazardous waste discharges, such as spent catalysts or contaminated carbon. Generally, these types of environmental concerns become important when sensitive site-specific receptors exist or when the incremental emissions reductions potential of the more stringent control is only marginally greater than the next most-effective option. However, the fact that a control device creates liquid and solid waste that must be disposed of does not necessarily argue against selection of that technology as BART, particularly if the control device has been applied to similar facilities elsewhere and the solid or liquid waste is similar to those other applications. On the other hand, where you or the source owner can show that unusual circumstances at the proposed facility create greater problems than experienced elsewhere, this may provide a basis for the elimination of that control alternative as BART.

The SO_2 control technologies we considered in our analysis—DSI and scrubbers—are in wide use in the coal-fired electricity generation industry. Both technologies add spent reagent to the waste stream already generated by the facilities we analyzed, but do not present any unusual environmental impacts. As discussed below in our cost analyses for DSI and SDA SO_2 scrubbers, our cost model includes waste disposal costs in the variable operating costs. Consequently, we believe that with one possible exception, any non-air quality environmental impacts have been adequately considered in our analyses. We are aware that the Harrington facility has instituted a water recycling program and obtains some of its water from the City of Amarillo.[99] Due to potential non-air quality concerns, we limit our SO_2 control analysis for Harrington to DSI and dry scrubbers.

Regarding the remaining useful life, the BART Guidelines advise: [100]

You may decide to treat the requirement to consider the source's ''remaining useful life'' of the source for BART determinations as one element of the overall cost analysis. The ''remaining useful life'' of a source, if it represents a relatively short time period, may affect the annualized costs of retrofit controls. For example, the methods for calculating annualized costs in EPA's OAQPS Control Cost Manual require the use of a specified time period for amortization that varies based upon the type of control. If the remaining useful life will clearly exceed this time period, the remaining useful life has essentially no effect on control costs and on the BART determination process. Where the remaining useful life is less than the time period for amortizing costs, you should use this shorter time period in your cost calculations.

We are unaware that any of the facilities we have analyzed for BART have entered into an enforceable document to shut down the applicable units earlier than what would occur under our assumed 30-year operational life.[101] As we stated in our Oklahoma FIP,[102] we noted that scrubber vendors indicate that the lifetime of a scrubber is equal to the lifetime of the boiler, which might easily be well over 60 years. We identified specific scrubbers installed between 1975 and 1985 that were still in operation. Because a DSI system is relatively simple and reliable, we have no reason to conclude that its service life would be any less than what we typically use for scrubber cost analyses. Because none of the facilities involved have entered into enforceable documents to shut down the applicable units earlier, we will continue to use a 30-year equipment life for DSI, scrubber retrofits, and scrubber upgrades, as we believe that is proper.

5. Step 5: Evaluate Visibility Impacts

Please see the BART Modeling TSD, where we describe in detail the various modeling runs we conducted, our methodology and selection of emission rates, modeling results, and final modeling analysis that we used to evaluate the benefits of the proposed controls and their associated emission decreases on visibility impairment values. Below we present a summary of our analysis and our proposed findings regarding the estimated visibility benefits of emission reductions based on the CALPUFF and/or CAMx modeling results.

a. Visibility Benefits of DSI, SDA, and Wet FGD for Coal-Fired Units

We evaluated the visibility benefits of DSI, for the twelve units depicted in Tables 15 and 16 below that currently have no SO_2 control. We evaluated all the units using the control levels we employed in our control cost analyses. In summary, we evaluated these units at a DSI SO_2 control level of 50%, which we believe is likely achievable for any unit. At the lower performance level we assumed, we conclude that the corresponding visibility benefits from DSI in most cases would be close to half of the benefits from scrubbers resulting in the visibility benefits from scrubber retrofits being much more beneficial. We also evaluated the visibility benefits for scrubber retrofits (wet FGD and SDA) for these same units, assuming the same control levels corresponding to SDA and wet FGD that we used in our control cost analyses. For those sources that are within 300 to 400 km of a Class

[96] For example, switching from 0.7% sulfur fuel oil to ULSD at 0.0015% sulfur results in a reduction in sulfur emissions of 99.8% compared to an estimated 98% reduction due to the use of a scrubber.

[97] 70 FR 39103, 39168 (July 6, 2005), [40 CFR part 51, App. Y.].

[98] 70 FR at 39169 (July 6, 2005), [40 CFR part 51, App. Y.].

[99] *http://www.powermag.com/xcel-energys-harrington-generating-station-earns-powder-river-basin-coal-users-group-award/.*

[100] 70 FR 39103, 39169, [40 CFR part 51, App. Y.].

[101] We received a November 21, 2016 letter from the source owner regarding Parish Units 5 & 6. The letter, now added to the docket, explains the units have natural gas firing capabilities and expresses interest in obtaining flexibility to avoid BART or obtaining multiple options for complying with BART. While we acknowledge this interest, the letter does not provide or commit to any specifics in furtherance of the BART analysis that EPA is now required to conduct under the BART Guidelines.

[102] Response to Technical Comments for Sections E. through H. of the **Federal Register** Notice for the Oklahoma Regional Haze and Visibility Transport Federal Implementation Plan, Docket No. EPA–R06–OAR–2010–0190, 12/13/2011. See discussion beginning on page 36.

I area, we utilized CALPUFF and CAMx modeling to assess the visibility benefit of potential controls. For the remaining coal-fired sources (J T Deely, Coleto Creek, Fayette and W A Parish), only CAMx modeling was utilized as these sources are located at much greater distances to the nearest Class I areas. In evaluating the impacts and benefits of potential controls, we utilized a number of metrics, including change in deciviews and number of days impacted over 0.5 dv and 1.0 dv. Consistent with the BART Guidelines, the visibility impacts and benefits modeled in CALPUFF and CAMx are calculated as the change in deciviews compared against natural visibility conditions.[103] We note that the high control scenario modeling for Fayette units 1 and 2 demonstrate the benefit from existing high performing controls. As discussed elsewhere, we found that for these units no additional controls or upgrades were necessary. For a full discussion of our review of all the modeling results, and factors that we considered in evaluating and weighing all the results, see our BART Modeling TSD. Below, we present a summary of some of those visibility benefits at the Class I areas most impacted by each source:

TABLE 15—VISIBILITY BENEFIT OF RETROFIT CONTROLS: COAL-FIRED UNITS (CAMX MODELING)

Facility name	Emission unit	Class I area	Metric	Visibility impact			Visibility benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Big Brown	Source (Unit 1 and 2)	WIMO	Max dv	4.017	2.249	0.474	1.768	3.542
			Days >0.5 dv	65	33	0	32	65
			Days >1.0 dv	33	13	0	20	33
		CACR	Max dv	3.775	2.539	0.787	1.236	2.988
			Days >0.5 dv	91	62	4	29	87
			Days >1.0 dv	57	21	0	36	57
	Unit 1	WIMO	Max dv	2.154	1.168	0.245	0.986	1.909
			Days >0.5 dv	33	13	0	20	33
			Days >1.0 dv	12	1	0	11	12
		CACR	Max dv	2.016	1.327	0.409	0.688	1.606
			Days >0.5 dv	58	22	0	36	58
			Days >1.0 dv	17	4	0	13	17
	Unit 2	WIMO	Max dv	2.175	1.181	0.235	0.994	1.940
			Days >0.5 dv	34	13	0	21	34
			Days >1.0 dv	12	1	0	11	12
		CACR	Max dv	2.033	1.338	0.391	0.695	1.642
			Days >0.5 dv	58	23	0	35	58
			Days >1.0 dv	17	4	0	13	17
Monticello	Source (Unit 1, 2 and 3)	CACR	Max dv	10.498	6.121	2.079	4.377	8.419
			Days >0.5 dv	152	107	28	45	124
			Days >1.0 dv	111	54	8	57	103
		WIMO	Max dv	5.736	2.769	0.774	2.968	4.962
			Days >0.5 dv	67	35	4	32	63
			Days >1.0 dv	40	14	0	26	40
	Unit 1	CACR	Max dv	4.516	3.123	0.733	1.393	3.783
			Days >0.5 dv	79	43	3	36	76
			Days >1.0 dv	32	16	0	16	32
		WIMO	Max dv	2.241	1.290	0.252	0.951	1.989
			Days >0.5 dv	30	10	0	20	30
			Days >1.0 dv	8	2	0	6	8
	Unit 2	CACR	Max dv	4.487	3.065	0.563	1.422	3.924
			Days >0.5 dv	78	42	1	36	77
			Days >1.0 dv	30	13	0	17	30
		WIMO	Max dv	2.189	1.252	0.186	0.937	2.003
			Days >0.5 dv	30	10	0	20	30
			Days >1.0 dv	6	2	0	4	6
Coleto Creek	Source (Unit 1)	WIMO	Max dv	0.845	0.526	0.176	0.318	0.668
			Days >0.5 dv	9	1	0	8	9
			Days >1.0 dv	0	0	0	0	0
		CACR	Max dv	0.791	0.458	0.186	0.333	0.606
			Days >0.5 dv	5	0	0	5	5
			Days >1.0 dv	0	0	0	0	0
Harrington [1]	Source (Unit 061B & 062B)	SACR	Max dv	5.288	4.287	3.235	1.001	2.053
			Days >0.5 dv	13	7	3	6	10
			Days >1.0 dv	5	1	1	4	4
		WIMO	Max dv	4.928	4.362	3.798	0.565	1.130
			Days >0.5 dv	15	11	6	4	9
			Days >1.0 dv	6	5	4	1	2
	Unit 061B	SACR	Max dv	2.908	2.322	1.738	0.586	1.170
			Days >0.5 dv	5	1	1	4	4
			Days >1.0 dv	1	1	1	0	0
		WIMO	Max dv	2.708	2.382	2.065	0.326	0.643
			Days >0.5 dv	6	5	4	1	2
			Days >1.0 dv	4	2	1	2	3
	Unit 062B	SACR	Max dv	2.998	2.373	1.719	0.625	1.279
			Days >0.5 dv	5	1	1	4	4
			Days >1.0 dv	1	1	1	0	0
		WIMO	Max dv	2.770	2.407	2.046	0.363	0.723
			Days >0.5 dv	6	5	4	1	2
			Days >1.0 dv	4	1	1	3	3

[103] 40 CFR 51 Appendix Y, IV.D.5: ''Calculate the model results for each receptor as the change in deciviews compared against natural visibility conditions.''

TABLE 15—VISIBILITY BENEFIT OF RETROFIT CONTROLS: COAL-FIRED UNITS (CAMX MODELING)—Continued

Facility name	Emission unit	Class I area	Metric	Visibility impact			Visibility benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
J T Deely	Source (Sommers 1&2, J T Deely 1&2).	WIMO	Max dv	1.513	0.939	0.814	0.574	0.699
			Days >0.5 dv	47	8	1	39	46
			Days >1.0 dv	6	0	0	6	6
		CACR	Max dv	1.423	1.155	0.905	0.268	0.518
			Days >0.5 dv	7	3	2	4	5
			Days >1.0 dv	2	1	0	1	2
	J T Deely 1	WIMO	Max dv	0.757	0.449	0.270	0.307	0.487
			Days >0.5 dv	4	0	0	4	4
			Days >1.0 dv	0	0	0	0	0
		BIBE	Max dv	0.652	0.373	0.069	0.279	0.583
			Days >0.5 dv	2	0	0	2	2
			Days >1.0 dv	0	0	0	0	0
	J T Deely 2	WIMO	Max dv	0.632	0.387	0.334	0.245	0.298
			Days >0.5 dv	3	0	0	3	3
			Days >1.0 dv	0	0	0	0	0
		CACR	Max dv	0.604	0.490	0.387	0.114	0.217
			Days >0.5 dv	2	0	0	2	2
			Days >1.0 dv	0	0	0	0	0
W.A. Parish	Source (WAP 4, 5, & 6)	CACR	Max dv	3.177	2.032	0.511	1.145	2.665
			Days >0.5 dv	54	26	1	28	53
			Days >1.0 dv	22	9	0	13	22
		UPBU	Max dv	1.994	1.215	0.234	0.779	1.760
			Days >0.5 dv	34	14	0	20	34
			Days >1.0 dv	9	1	0	8	9
	WAP 5	CACR	Max dv	1.698	1.052	0.180	0.646	1.518
			Days >0.5 dv	22	9	0	13	22
			Days >1.0 dv	8	1	0	7	8
		UPBU	Max dv	1.038	0.613	0.094	0.424	0.943
			Days >0.5 dv	11	1	0	10	11
			Days >1.0 dv	1	0	0	1	1
	WAP 6	CACR	Max dv	1.648	1.018	0.156	0.630	1.492
			Days >0.5 dv	22	8	0	14	22
			Days >1.0 dv	6	1	0	5	6
		UPBU	Max dv	1.003	0.591	0.081	0.412	0.922
			Days >0.5 dv	9	1	0	8	9
			Days >1.0 dv	1	0	0	1	1
Welsh [2]	Source (Unit 1 & 2)	CACR	Max dv	4.576	....	0.822	....	3.754
			Days >0.5 dv	92	....	3	....	89
			Days >1.0 dv	39	....	0	....	39
		MING	Max dv	2.544	....	0.570	....	1.973
			Days >0.5 dv	9	....	1	....	8
			Days >1.0 dv	3	....	0	....	3
	Unit 1	CACR	Max dv	2.343	1.659	0.822	0.684	1.521
			Days >0.5 dv	37	18	3	19	34
			Days >1.0 dv	8	3	0	5	8
		MING	Max dv	1.150	0.886	0.570	0.264	0.579
			Days >0.5 dv	2	1	1	1	1
			Days >1.0 dv	1	0	0	1	1
Fayette [2]	Source (Unit 1 & 2)	CACR	Max dv	1.894	....	0.903	....	0.991
			Days >0.5 dv	26	....	2	....	24
			Days >1.0 dv	9	....	0	....	9
		WIMO	Max dv	1.175	....	0.580	....	0.595
			Days >0.5 dv	19	....	1	....	18
			Days >1.0 dv	2	....	0	....	2
	Unit 1	CACR	Max dv	1.002	....	0.480	....	0.522
			Days >0.5 dv	9	....	0	....	9
			Days >1.0 dv	1	....	0	....	1
		WIMO	Max dv	0.609	....	0.306	....	0.302
			Days >0.5 dv	2	....	0	....	2
			Days >1.0 dv	0	....	0	....	0
	Unit 2	CACR	Max dv	0.974	....	0.441	....	0.534
			Days >0.5 dv	9	....	0	....	9
			Days >1.0 dv	0	....	0	....	0
		WIMO	Max dv	0.598	....	0.282	....	0.316
			Days >0.5 dv	2	....	0	....	2
			Days >1.0 dv	0	....	0	....	0

[1] Harrington high control scenario for both units is SDA at 95% reduction.

[2] Welsh Unit 2 and Fayette Units 1 & 2 were not modeled at DSI level control. Welsh Unit 2 has shut down and Fayette units have WFGD (wet FGD) installed. Welsh source-wide modeling for high control includes a unit 2 shutdown.

TABLE 16—VISIBILITY BENEFIT OF RETROFIT CONTROLS: COAL-FIRED UNITS (CALPUFF MODELING)

Facility name	Emission unit	Class I area	Metric	Visibility impact			Visibility benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Big Brown	Source (Units 1 and 2).	WIMO	Max dv	4.27	2.54	0.43	1.73	3.83
			Days >0.5 dv Avg.	67.33	43.33	2.67	24.00	64.67
			Days >1.0 dv Avg.	42.00	21.00	1.00	21	41.00
		CACR	Max dv	4.03	2.41	0.47	1.62	3.55
			Days >0.5 dv Avg.	91.67	64.33	4.67	27.33	87.00
			Days >1.0 dv Avg.	60.33	30.00	0.00	30.33	60.33
Monticello[1]	Source (Unit 1, 2 and 3).	CACR	Max dv	6.57	3.68	1.70	2.89	4.87
			Days >0.5 dv Avg.	143.67	115.00	62.33	28.67	81.33
			Days >1.0 dv Avg.	113.00	66.33	23.67	46.67	89.33
		UPBU[4]	Max dv	3.45	1.77	0.77	1.68	2.68
			Days >0.5 dv Avg.	103.00	61.00	13.67	42.00	89.33
			Days >1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days >0.5 dv Avg.	60.00	34.67	6.00	25.33	54.00
			Days >1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67
Harrington[2]	Source (Units 061B & 062B).	SACR	Max dv	1.06	0.86	0.61	0.20	0.45
			Days >0.5 dv Avg.	21.00	15.33	6.33	5.67	14.67
			Days >1.0 dv Avg.	6.67	3.00	0.67	3.67	6.00
		WIMO	Max dv	1.29	0.97	0.55	0.32	0.74
			Days >0.5 dv Avg.	26.00	15.33	8.67	10.67	17.33
			Days >1.0 dv Avg.	9.00	4.67	1.33	4.33	7.67
Welsh[3]	Source (Unit 1)	CACR	Max dv	1.44	1.12	0.72	0.32	0.72
			Days >0.5 dv Avg.	50.33	32.67	12.33	17.67	38
			Days >1.0 dv Avg.	15.33	8.00	2.33	7.33	13.00
		UPBU	Max dv	0.76	0.49	0.22	0.27	0.54
			Days >0.5 dv Avg.	12.00	4.67	0.33	7.33	11.67
			Days >1.0 dv Avg.	0.67	0.00	0.00	0.67	0.67
		WIMO	Max dv	0.56	0.33	0.15	0.23	0.41
			Days >0.5 dv Avg.	7.33	2.67	0.33	4.67	7.00
			Days >1.0 dv Avg.	1.33	0.33	0.00	1.00	1.33

[1] Monticello's controlled level is a combination of scrubber upgrades and scrubber install in the facility impact modeling with CALPUFF.
[2] Harrington high control scenario for both units is SDA at 95% reduction.
[3] Welsh Unit 2 and Fayette Units 1 & 2 were not modeled at DSI level control. Welsh Unit 2 has shut down and Fayette units have WFGD installed. Welsh source-wide modeling for high control includes a unit 2 shutdown.
[4] UPBU = Upper Buffalo Wilderness Area.

b. Visibility Benefits of Scrubber Upgrades for Coal-Fired Units

We also modeled the visibility benefits of those same units for which we conducted control cost analysis for upgrading their existing scrubbers. We assumed the same 95% control level we used in our control cost analyses. We also modeled a lower level control at 90%. The visibility benefits from these scrubber upgrades are quantified specifically in our BART Modeling TSD. Below, we present a summary of the del-dv visibility benefits and reduction in number of days impacted.

TABLE 17—VISIBILITY BENEFIT OF SCRUBBER UPGRADES: COAL-FIRED UNITS (CAMX MODELING)

Facility name	Emission unit	Class I area	Metric	Visibility impact			Visibility benefit	
				Baseline	(90%) control	(95%) control	(90%) benefit	(95%) benefit
Martin Lake	Source (Unit 1, 2 & 3).	CACR	Max dv	6.651	4.491	4.321	2.159	2.329
			Days >0.5 dv	141	75	56	66	85
			Days >1.0 dv	99	31	16	68	83
		UPBU	Max dv	5.803	2.669	2.528	3.134	3.275
			Days >0.5 dv	99	39	22	60	77
			Days >1.0 dv	67	11	7	56	60
	Unit 1	CACR	Max dv	2.633	1.550	1.468	1.083	1.165
			Days >0.5 dv	71	17	6	54	65
			Days >1.0 dv	26	3	1	23	25
		UPBU	Max dv	2.254	0.867	0.805	1.387	1.449
			Days >0.5 dv	44	6	3	38	41
			Days >1.0 dv	10	0	0	10	10
	Unit 2	CACR	Max dv	2.466	1.882	1.811	0.585	0.655
			Days >0.5 dv	68	18	9	50	59
			Days >1.0 dv	26	3	1	23	25
		UPBU	Max dv	2.189	1.077	1.025	1.112	1.164
			Days >0.5 dv	40	6	5	34	35
			Days >1.0 dv	10	1	1	9	9
	Unit 3	CACR	Max dv	2.755	1.682	1.609	1.074	1.146
			Days >0.5 dv	76	15	6	61	70
			Days >1.0 dv	29	2	1	27	28
		UPBU	Max dv	2.368	0.942	0.890	1.425	1.478
			Days >0.5 dv	46	6	4	40	42

TABLE 17—VISIBILITY BENEFIT OF SCRUBBER UPGRADES: COAL-FIRED UNITS (CAMX MODELING)—Continued

Facility name	Emission unit	Class I area	Metric	Visibility impact			Visibility benefit	
				Baseline	(90%) control	(95%) control	(90%) benefit	(95%) benefit
			Days >1.0 dv	13	0	0	13	13
Monticello	Source (Unit 1, 2 and 3).	CACR	Max dv	10.498	6.121	2.079	4.377	8.419
			Days >0.5 dv	152	107	28	45	124
			Days >1.0 dv	111	54	8	57	103
		WIMO	Max dv	5.736	2.769	0.774	2.968	4.962
			Days >0.5 dv	67	35	4	32	63
			Days >1.0 dv	40	14	0	26	40
	Unit 3	CACR	Max dv	4.632	0.905	0.914	3.728	3.719
			Days >0.5 dv	79	5	5	74	74
			Days >1.0 dv	32	0	0	32	32
		WIMO	Max dv	2.282	0.462	0.364	1.820	1.918
			Days >0.5 dv	31	0	0	31	31
			Days >1.0 dv	7	0	0	7	7

TABLE 18—VISIBILITY BENEFIT OF SCRUBBER UPGRADES: COAL-FIRED UNITS (CALPUFF MODELING)

Facility name	Emission unit	Class I area	Metric	Visibility impact			Visibility benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Martin Lake	Source (Units 1, 2 & 3).	CACR	Max dv	4.46	2.27	1.86	2.18	2.60
			Days >0.5 dv Avg.	129.67	77.33	63.00	52.33	66.67
			Days >1.0 dv Avg.	91.33	32.67	22.33	58.67	69.00
		UPBU	Max dv	2.73	1.10	0.85	1.63	1.88
			Days >0.5 dv Avg.	81.67	30.33	18.67	51.33	63.00
			Days >1.0 dv Avg.	46.67	7.33	3.67	39.33	43.00
Monticello [1]	Source (Unit 1, 2 and 3).	CACR	Max dv	6.57	3.68	1.70	2.89	4.87
			Days >0.5 dv Avg.	143.67	115	62.33	28.67	81.33
			Days >1.0 dv Avg.	113	66.33	23.67	46.67	89.33
		UPBU	Max dv	3.45	1.77	0.765	1.68	2.68
			Days >0.5 dv Avg.	103	61	13.67	42	89.33
			Days >1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days >0.5 dv Avg.	60	34.67	6	25.33	54
			Days >1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67

[1] Monticello's controlled level is a combination of scrubber upgrade on Unit 3 and scrubber retrofits on Units 1 and 2 in the facility impact modeling with CALPUFF.

c. Visibility Benefits of Fuel Oil Switching for Gas/Fuel Oil-Fired Units

We also modeled the visibility benefits of those gas/fuel oil-fired units for which we conducted control cost analysis for switching to lower sulfur fuels. We evaluated the visibility benefits of switching to fuel oils corresponding to ultra-low sulfur diesel at 0.0015% sulfur by weight and 0.3% sulfur by weight as we evaluated in our control cost analyses. The visibility benefits from these fuel switches are quantified specifically in our BART Modeling TSD. Below, we present a summary of the del-dv visibility benefits.

TABLE 19—VISIBILITY BENEFITS FROM LOWER SULFUR FUEL

Facility name	Emission unit	Baseline visibility impact from source (most impacted Class I area)	Visibility benefit of 0.3% S fuel oil	Visibility benefit of 0.0015% S fuel oil
Stryker	ST2	CALPUFF 0.65% S: 0.786 dv @ CACR (Facility).	CALPUFF (0.3% S): 0.263 dv @ CACR (Facility).	CALPUFF: 0.522 dv @ CACR (Facility)
Graham	Unit 2	CALPUFF 0.69% S: 1.228 dv @ WIMO (Facility).	CALPUFF (0.3% S): 0.465 dv @ WIMO (Facility.	CALPUFF: 0.851 dv @ WIMO (Facility)
Wilkes	Units 1, 2, 3	CALPUFF 0.43% S: 0.698 dv @ CACR (Facility).	CALPUFF (0.1% S): 0.029 dv @ CACR (Facility).	CALPUFF: 0.037 dv @ CACR (Facility)
Newman [1]	Unit 2	N/A	N/A	N/A
	Unit 3	N/A	N/A	N/A
	Unit 4	N/A	N/A	N/A
Calaveras	Sommers Unit 1	CAMx: 1.513 dv @ WIMO (Source); 0.106 dv @ CACR (Unit).	0.004 dv @ CACR	0.008 dv @ CACR

TABLE 19—VISIBILITY BENEFITS FROM LOWER SULFUR FUEL—Continued

Facility name	Emission unit	Baseline visibility impact from source (most impacted Class I area)	Visibility benefit of 0.3% S fuel oil	Visibility benefit of 0.0015% S fuel oil
	Sommers Unit 2	CAMx: 1.513 dv @ WIMO (Source); 0.180 dv @ CACR (Unit).	0.023 @ CACR	0.047 @ CACR

[1] Newman is on the edge of the CALMET and CALPUFF modeling grids for the database that were used in this action. Since the facility was near the edge, emissions of the facility's impacts could not be adequately modeled since some of the plumes could have gone out of the grid and not be adequately assessed if they come back into the grid and transport to impact a Class I area.

6. BART Analysis for PM

In our recent Texas-Oklahoma FIP, we initially proposed to approve Texas' determination that no PM BART controls were appropriate for its EGUs, based on a screening analysis of the visibility impacts from just PM emissions and the premise that EGU SO_2 and NO_X were covered separately by participation in CSAPR (allowing consideration of PM emissions in isolation). Because of the CSAPR remand and resulting uncertainty regarding SO_2 and NO_X BART for EGUs, we decided not to finalize our proposed approval of Texas' PM BART determination.[104] For reasons earlier stated we are proposing to disapprove the SIP determination regarding PM BART for EGUs. Following from that proposed disapproval, we are proposing a PM BART FIP for those Texas EGUs that are subject to BART.

The BART Guidelines permit us to conduct a streamlined analysis of PM BART in two key ways. First, the Guidelines allow a streamlined analysis for PM sources subject to MACT standards. Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, the Guidelines state it is permissible to rely on MACT standards for purposes of BART.[105]

Second, with respect to gas-fired units, which have inherently low emissions of PM (as well as SO_2), the Regional Haze Rule did not specifically envision new or additional controls or emissions reductions from the PM BART requirement. The BART guidelines preclude us from stating that PM emissions are *de minimis* when plant-wide emissions exceed 15 tons per years. While we must assign PM BART determinations to the gas-firing units, there are no practical add-on controls to consider for setting a more stringent PM BART emissions limit. The Guidelines state that if the most stringent controls are made federally enforceable for BART, then the otherwise required analyses leading up to the BART determination can be skipped.[106]

With this background, we are providing our evaluation along with some supplementary information on the BART sources as divided into two categories: coal-fired EGUs, and gas-fired EGUs.

BART Analysis for PM for Coal-Fired Units

All of the coal-fired EGUs that are subject to BART are currently equipped with either Electrostatic Precipitators (ESPs) or baghouses, or both, as can be seen from Table 20:

TABLE 20—CURRENT PM CONTROLS FOR COAL-FIRED UNITS SUBJECT TO BART

Facility name	Unit ID	Fuel type (primary)	SO_2 control(s)	PM control(s)
Big Brown	1	Coal		Baghouse + Electrostatic Precipitator.
Big Brown	2	Coal		Baghouse + Electrostatic Precipitator.
Coleto Creek	1	Coal		Baghouse.
Harrington Station	061B	Coal		Electrostatic Precipitator.
Harrington Station	062B	Coal		Baghouse.
J T Deely	1	Coal		Baghouse.
J T Deely	2	Coal		Baghouse.
Martin Lake	1	Coal	Wet Limestone	Electrostatic Precipitator.
Martin Lake	2	Coal	Wet Limestone	Electrostatic Precipitator.
Martin Lake	3	Coal	Wet Limestone	Electrostatic Precipitator.
Monticello	1	Coal		Baghouse + Electrostatic Precipitator.
Monticello	2	Coal		Baghouse + Electrostatic Precipitator.
Monticello	3	Coal	Wet Limestone	Electrostatic Precipitator.
Fayette	1	Coal	Wet Limestone	Electrostatic Precipitator.
Fayette	2	Coal	Wet Limestone	Electrostatic Precipitator.
W A Parish	WAP5	Coal		Baghouse.
W A Parish	WAP6	Coal		Baghouse.
Welsh Power Plant	1	Coal		Baghouse (Began Nov 15, 2015) + Electrostatic Precipitator.

As an initial matter, we examine the control efficiencies of both baghouses and ESPs. We consider a baghouse, widely reported to be capable of 99.9% control of PM, to be the maximum level control for PM and so the units equipped with a baghouse will not be further analyzed for PM BART. The remaining units are fitted with ESPs.

The particulate matter control efficiency of ESPs varies somewhat with

[104] 81 FR 302 (January 5, 2016).

[105] 70 FR 39163–39164.

[106] 70 FR 39165 (''. . . you may skip the remaining analyses in this section, including the visibility analysis . . .'')

the design, the resistivity of the particulate matter, and the maintenance of the ESP. We do not have any information on the control level efficiency of any of the ESPs for the units in question. However, reported control efficiencies for well-maintained ESPs typically range from greater than 99% to 99.9%.[107] We consider this pertinent in concluding that the potential additional particulate control that a baghouse can offer over an ESP is relatively minimal.[108] In other words, if we did obtain control information specific to the ESP units in question, we do not believe that additional information would lead us to a different conclusion.

Nevertheless, w'e will examine the potential cost of retrofitting a typical 500 MW coal fired unit with a baghouse. Using our baghouse cost algorithms, as employed in version 5.13 of our IPM model,[109] and assuming a conservative air to cloth ratio of 6.0, results in a capital engineering and construction cost of $77,428,000.[110] Applied to the subject units, this cost assumes a retrofit factor of 1.0, and does not consider the demolition of the existing ESP, should it be required in order to make space for the baghouse.

We do not calculate the cost-effectiveness resulting from replacing an ESP with a baghouse. However, we expect that the tons of additional PM removed by a baghouse over an ESP to be very small, which would result in a very high cost-effectiveness figure. Also, we do not model the visibility benefit of replacing an ESP with a baghouse. However, our visibility impact modeling indicates that the baseline PM emissions of these units are very small, so we expect that the visibility improvement from replacing an ESP with a baghouse to be a small fraction of that. For instance, our CAMx baseline modeling shows that on a source-wide level, impacts from PM emissions on the maximum impacted days from each source at each Class I area was 3% of the total visibility impairment or less (calculated as percent of total extinction due to the source). Therefore additional PM controls are anticipated to result in very little visibility benefit on the maximum impacted days. Similarly, our CALPUFF modeling indicates that visibility impairment from PM is also a small fraction (typically only a few percent) of the total visibility impairment due to each source.

Adding to the above discussion, we are tasked to assign the enforceable emission limitations that constitute PM BART. We believe a stringent control level that would be met with existing or otherwise-required controls is a filterable PM limit of 0.03 lb/MMBtu for each of the coal-fired units subject to BART. We note that the Mercury and Air Toxics (MATS) Rule establishes an emission standard of 0.03 lb/MMBtu filterable PM (as a surrogate for toxic non-mercury metals) as representing Maximum Achievable Control Technology (MACT) for coal-fired EGUs.[111] This standard derives from the average emission limitation achieved by the best performing 12 percent of existing coal-fired EGUs, as based upon test data used in developing the MATS Rule. We are not familiar with any new technologies subsequent to this standard that could lead to any cost effective increases in the level of control; thus, consistent with the BART Guidelines, we are proposing to rely on this limit for purposes of PM BART for all of the coal-fired units as part of our FIP. We understand the coal-fired units covered by this proposal to be subject to MATS, but to the extent the units may be following alternate limits that differ from the surrogate PM limits found in MATS, we welcome comments on different, appropriately stringent limits reflective of current control capabilities.[112] Because we anticipate that any limit we assign should be achieved by current control capabilities, we propose that compliance can be met at the effective date of the rule. To address periods of startups and shutdowns, we are further proposing that PM BART for these units will additionally be met by following the work practice standards specified in 40 CFR part 63, subpart UUUUU, Table 3, and using the relevant definitions in 63.10042. We are proposing that the demonstration of compliance can be satisfied by the methods for demonstrating compliance with filterable PM limits that are specified in 40 CFR part 63, subpart UUUUU, Table 7. However, we would give consideration to commenter-submitted requests for alternate or additional methods of demonstrating compliance.

BART Analysis for PM for Gas-Fired Units

We note that PM emissions for the gas-only fired units that are subject to BART are inherently low.[113] We therefore conclude that PM emissions from natural gas firing is so minimal that the installation of any additional PM controls on the unit would likely achieve very low emissions reductions and have minimal visibility benefits. As there are no appropriate add-on controls and the status quo reflects the most stringent controls, we are proposing to make the requirement to burn pipeline natural gas federally enforceable. We note that in addition to satisfying PM BART, this limitation will also serve to satisfy SO_2 BART for these gas-fired units, as well as the fuel-oil units when they fire natural gas. We are proposing that PM and SO_2 BART for gas fired-units will limit fuel to pipeline natural gas, as defined at 40 CFR 72.2.

The available PM controls for gas units that also burn fuel oil are the same for the coal-fired units. We would expect similar costs for installing a baghouse on a typical gas-fired boiler that occasionally burns fuel oil. Again, our visibility impact modeling indicates that the baseline PM emissions of these units are very small, so we expect that the visibility improvement from the installation of a baghouse to be a small fraction on the order of 1–3% of the visibility impacts from the facility. We are confident that the cost of retrofitting the subject units with a baghouse would be extremely high compared to the visibility benefit for any of the units currently fitted with an ESP. We conclude that the cost of a baghouse does not justify the minimal expected improvement in visibility for these units. Accordingly, we are proposing that the fuel content limits for oil burning that we propose to meet SO_2 BART will also satisfy PM BART.

[107] EPA, ''Air Pollution Control Technology Fact Sheet: Dry Electrostatic Precipitator (ESP)—Wire Plate Type,'' EPA–452/F–03–028. Grieco, G., ''Particulate Matter Control for Coal-fired Generating Units: Separating Perception from Fact,'' *apcmag.net,* February, 2012. Moretti, A. L.; Jones, C. S., ''Advanced Emissions Control Technologies for Coal-Fired Power Plants, Babcox and Wilcox Technical Paper BR–1886, Presented at Power-Gen Asia, Bangkok, Thailand, October 3–5, 2012.

[108] We do not discount the potential health benefits this additional control can have for ambient PM. However, the regional haze program is only concerned with improving the visibility at Class I areas.

[109] IPM Model—Updates to Cost and Performance for APC Technologies, Particulate Control Cost Development Methodology, Final March 2013, Project 12847–002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy. Documentation for v.5.13: Chapter 5: Emission Control Technologies, Attachment 5–7: PM Cost Methodology, downloaded from: *https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-7_pm_cost_methodology.pdf.*

[110] *Id.* See page 9.

[111] 77 FR 9304, 9450, 9458 (February 16, 2012) (codified at 40 CFR 60.42 Da(a), 60.50 Da(b)(1)); 40 CFR part 63 Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units.

[112] The various limits are provided at 40 CFR part 63, subpart UUUUU, Table 2 (''Emission Limits for Existing EGUs'').

[113] AP 42, Fifth Edition, Volume 1, Chapter 1: External Sources, Section 1.4, Natural Gas Combustion, available here: *https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf.*

Lastly, should our assumptions regarding the frequency and type of fuel oil burned in these units significantly change, we expect that Texas will address such a change appropriately in its SIP, which we will review in the next planning period.

D. How, if at all, do issues of ''*Grid Reliability*'' *relate to the proposed BART determinations?*

On July 15, 2016, a preliminary order of the Fifth Circuit Court of Appeals took the view that EPA's Texas-Oklahoma FIP (81 FR 295, January 5, 2016) gave a ''truncated discussion of grid reliability'' and additionally stated that ''the agency may not have fulfilled its statutory obligation to consider the energy impacts of the FIP.'' The Court's preliminary ruling made particular reference to ''the explicit directive in the [CAA] that implementation plans 'take[ ] into consideration . . . the energy . . . impacts of compliance,' 42 U.S.C. 7491(g)(1).'' [114] Because the BART requirement at issue in this proposal has similar language on *energy impacts of compliance* appearing at 42 U.S.C. 7491(g)(2), we wish to provide a clear explanation on how grid-related considerations for EGUs could bear on this proposal.

First, the BART factor for *energy impacts of compliance* does not call for the examination of grid reliability considerations from alleged plans to shut down or retire a unit rather than comply with a more stringent emission limit or limits. The language instead calls for consideration of energy impacts from *complying* by installing retrofit controls on a source that continues in operation. In this regard, our proposal follows the required BART Guidelines for EGUs.[115] The Guidelines explain that the energy impacts factor relates to the penalties and benefits that may be associated with the assessment of a control option, *e.g.,* whether (for power penalties) the operation of add-on control technology subtracts from the productive yield of electricity from an EGU (what is sometimes termed an auxiliary or parasitic load).[116] It is also useful to note that the statutory text, while using the word ''energy,'' can apply to sources that do not produce energy or electricity. Thus, the statutory text regarding ''energy impacts'' of compliance with BART is not confined to the power generating industry and does not dictate that we study grid reliability issues.

We have considered whether this topic has any separate relevance to our proposal. Various court filings, news accounts, and industry market reports suggest that some source operators for some Texas BART units may be contemplating unit retirements. The BART Guidelines directly address such scenarios under the ''remaining useful life'' factor: ''there may be situations where a source operator intends to shut down a source . . . . but wishes to retain the flexibility to continue operating beyond that date in the event, for example, the market conditions change.'' [117] The Guidelines advise that a source that is willing to assure a permanent stop in operations with a federally- or State-enforceable restriction preventing further operation may obtain a short remaining useful life for BART analysis purposes that could then factor in the overall cost analysis.[118] As the Guidelines state, ''Where the remaining useful life is less the than the time period for amortizing costs, you should use this shorter period in your cost calculations.'' [119] We have no information on enforceable restrictions of this type for any of the units that we propose to be subject to BART. Absent that, we must assume that controls installed on the BART units will experience their full useful life. Affected sources are free to submit information as part of their comments containing appropriate enforceable documentation of shorter remaining useful lives.

We note, however, that the Guidelines recognize there may be cases where the installation of controls, even when cost-effective, would ''affect the viability of continued plant operations.'' [120] Under the Guidelines, where there are ''unusual circumstances,'' we are permitted to take into consideration ''the conditions of the plant and the economic effects of requiring the use of a control technology.'' [121] If the effects are judged to have a ''severe impact,'' those effects can be considered in the selection process. In such cases, the Guidelines counsel that any determinations be made with an economic analysis with sufficient detail for public review on the ''specific economic effects, parameters, and reasoning.'' [122] It is recognized, by the language of the Guidelines, that any such review process may entail the use of sensitive business information that may be confidential. The **ADDRESSES** section of this proposal explains how to submit confidential information with comments, and when claims of confidential business information, or CBI, are asserted with respect to any information that is submitted, the EPA regulations at 40 CFR part 2, subpart B-Confidentiality Business Information apply to protect it. All of that said, the Guidelines also advise that we may ''consider whether other competing plants in the same industry have been required to install BART controls if this information is available.'' [123] Because Texas EGUs are among the last to have SO_2 BART determinations, this information is available. It is indeed the case that other similar EGUs have been required to install the same types of SO_2 BART controls that we are proposing as very cost effective.[124]

We have considered the state of available information on whether the proposed controls could affect the viability of continued plant operations. On this point, we note that we are proposing BART determinations for several units where SO_2 control requirements were separately promulgated as part of the Texas-Oklahoma FIP. These under-controlled EGU sources are: Big Brown 1 and 2; Monticello 1, 2 and 3; Martin Lake 1, 2 and 3; and Coleto Creek 1. In litigation over the reasonable progress FIP, various declarations were filed on the issues of alleged forced closures and alleged reliability impacts. These declarations have been compiled and added to the docket for this rulemaking.

[114] EPA Guidance on this statutory language specifically explains that energy impacts are a matter of whether ''energy requirements associated with a control technology result in energy penalties.'' U.S. EPA, Office of Air Quality Planning and Standards, ''Guidance for Setting Reasonable Progress Goals under the Regional Haze Program,'' (June 1, 2007 rev), at Page 5–2.

[115] The promulgation of the Guidelines was required by 42 U.S.C. 7491(b)(1). Adherence to the Guidelines is mandatory for fossil-fuel fired generating power plants having total generating capacities ''in excess of 750 megawatts.''

[116] Other CAA provisions requiring consideration of ''energy impacts'' or ''energy requirements of the control technology'' are understood similarly. *See, e.g.,* CAA section 169 (the 1977 ''best available control technology'' requirement with consideration of ''energy . . . impacts''); *see also* CAA section 108 (''energy requirements . . . of the emission control technology; ''energy . . . impact of such processes, procedures, and methods [to reduce or control air pollution''); section 111 (''taking into account . . . energy requirements'' of an emission limitation), etc.

[117] *Id.* at 39169–39170.

[118] Similar to calculating a mortgage, remaining useful life is used in our cost-effectiveness analysis to calculate the annual cost of a particular control. The longer the remaining useful life, the smaller the total annualized cost, and the more cost-effective the control.

[119] *Id.* at 39169.

[120] 70 FR 39103, 39171 (July 6, 2005), [40 CFR part 51, App. Y].

[121] *Id.*

[122] 70 FR at 39171.

[123] *Id.*

[124] See for instance, the EIA information we present elsewhere in this notice in which we summarize the hundreds of scrubber installations that have been performed on similar EGUs.

By our review, these declarations do not appropriately inform or substantiate source-specific allegations of ''unusual circumstances'' that may have a severe impact on plant operations, because they do not offer any site-specific information.[125] Thus, we are unable to conclude that the proposed cost-effective BART controls would severely impact plant operations. Generalized claims of possible retirements and discussions on attributes of the market design of the Electric Reliability Council of Texas (ERCOT) cannot inform the statutorily required, source-specific BART determinations.

As a predicate to studying effects on transmission or reliability as ''unusual circumstances,'' we would require site-specific information from any source that would wish for us to potentially consider ''affordability of controls,'' under the terms specified in the Guidelines. Source owners may submit information, including information claimed to be CBI, for our assessment and consideration to potentially support an economic analysis that might be used in the BART selection process. As suggested by the Guidelines, the information necessary to inform our judgment would likely entail source-specific information on ''product prices, the market share, and the profitability of the source.'' Consideration of such information does not dictate what will be selected as a ''best'' alternative under the Guidelines, but it will substantiate the likelihood of a retirement scenario that would then give the parameters for: A non-conjectural examination of grid reliability issues; judging the significance or insignificance of such issues; and assessing whether such issues could be avoided through appropriate transmission planning. In sum, unless we are able to substantiate an ''affordability of controls'' problem for any particular unit and substantiate that a particular unit retirement would not be happening anyway at about the same time, alleged grid reliability impacts are speculative and are not able to inform these required BART determinations. As a final note, we acknowledge Executive Order 13211 (''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, and Use''). In cases where it does apply, agencies are ordered to prepare a Statement of Energy Effects for submission to the Administrator of the Office of Information and Regulatory Affairs (OIRA), Office of Management and Budget. This EGU BART proposal is not considered a significant regulatory action under Executive Order 12866, so the proposed action cannot be a ''significant energy action'' for purposes of Executive Order 13211 on that basis. This proposed action has also not been designated a significant energy action by the Administrator of OIRA, so Executive Order 13211 could not apply under that separate basis. With this proposal, there are no anticipated adverse effects on energy supply, distribution, or use that are meaningful or distinguishable from any other scenario where an EGU is expected to install cost-effective pollution controls required by the CAA.

IV. Our Weighing of the Five BART Factors

Below we present our reasoning for proposing our BART determinations for 29 EGUs in Texas, based on our analysis and weighing of the Five BART Factors: (1) Proposed SO_2 and PM BART determinations for 12 coal-fired units with no SO_2 controls, (2) proposed BART SO_2 and PM BART determinations for 6 coal-fired units with existing scrubbers, (3) proposed SO_2 and PM BART determinations 7 gas-fired units that occasionally burn fuel oil, and (4) proposed PM BART determinations for 4 gas-fired units.

In previous sections of this proposal, we have described how we assessed the five BART factors. In no case do we see any instance in which our assessment of energy impacts is a determining factor in assessing BART.[126] Also, in no case do we see any instance in which our assessment of the remaining useful life is a determining factor in assessing BART. Should a facility indicate in comments to us that the remaining useful life is less than the 30 years we have assumed in our control cost analyses, and is willing to enter into an enforceable document to that effect, we will adjust our cost-effectiveness calculation accordingly in making our final decision. In two cases, Harrington units 061B and 062B, we have limited our SO_2 control analysis for Harrington to DSI and dry scrubbers due to potential non-air quality concerns. In all other instances, we conclude that the cost of compliance, and the visibility benefits of controls are the controlling BART factors in our weighing of the five BART factors.

In considering cost-effectiveness and visibility benefit, we do not eliminate any controls based solely on the magnitude of the cost-effectiveness value, nor do we use cost-effectiveness as the primary determining factor. Rather, we compare the cost-effectiveness to the anticipated visibility benefit, and we take note of any additional considerations.[127] Also, in judging the visibility benefit we do not simply examine the highest value for a given Class I area, or a group of Class I areas, but we also consider the cumulative visibility benefit for all affected Class I areas, the number of days in a calendar year in which we see significant improvements, and other factors.[128]

First, we note that all of the sources addressed in our proposed BART determinations have already been shown to cause or contribute to visibility impairment at a Class I area as a condition of being subject-to-BART as part of the BART screening analysis. This analysis eliminated any BART-eligible source that emits lower amounts of visibility impacting pollutants, or otherwise impacts any Class I area at less than 0.5 deciviews. In fact, all of the individual units that we are proposing for BART controls exceed 0.5 deciviews on a unit basis, with most exceeding 1.0 deciview impact on a unit basis. As a consequence, all of the units we are proposing for BART controls are among the largest emitters of visibility impacting pollutants in Texas. A number of these units (*i.e.,* Big Brown, Martin Lake, Monticello, and Coleto Creek) were previously determined by us to require the same type and level of controls under the reasonable progress and long-term strategy provisions of the Regional Haze Rule that we are proposing here.[129]

Second, not discounting our approach of considering both cost-effectiveness and visibility benefit in unison, the cost-effectiveness of all of the controls that form the basis of our proposed BART determinations are within a range found to be acceptable in other cases.[130] As we

[125] Certain statements in declarations from representatives of both Luminant and Coleto Creek, who are the source owners of these facilities, cited compliance planning efforts that would be consistent with continued plant operations.

[126] In addition to our assessment of energy impacts, also see our discussion in Section III.D concerning our conclusion that energy impact considerations do not relate to potential electrical grid reliability issues.

[127] For instance, as we discuss later in Section IV.C why we believe that there are certain mitigating factors that should be considered when assessing BART for the gas-fired units that occasionally burn fuel oil.

[128] See for example 70 39130: ''comparison thresholds can be used in a number of ways in evaluating visibility improvement (*e.g.* the number of days or hours that the threshold was exceeded, a single threshold for determining whether a change in impacts is significant, a threshold representing an x percent change in improvement, etc.).''

[129] See our recent Texas-Oklahoma FIP, 81 FR 321.

[130] See for instance 79 FR 5048 (January 30, 2014): Jim Bridger BART determination of LNB/SOFA + SCR on Units 1–4; 77 FR 18070 (March 26, 2012): EPA proposed approval of Colorado's BART

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." [131]

A. SO_2 BART for Coal-fired Units With No SO_2 Controls

As we have discussed in this proposal and in our TSD, we have assumed two DSI control levels corresponding to 50% control and either a maximum of 80% or 90% control, depending on the particulate matter control device in use.[132] We did this to address the BART Guidelines directive that in evaluating technically feasible alternatives we "(1) [ensure we] express the degree of control using a metric that ensures an "apples to apples" comparison of emissions performance levels among options, and (2) [give] appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels." [133] In most cases, the cost-effectiveness of the higher control level of DSI was higher than either SDA or wet FGD. This was not the case for Monticello Unit 2; Harrington Unit 062B; and J T Deely Units 1 and 2.

However, these maximum DSI control levels are theoretical and we believe that any DSI control level above 50% must be confirmed by onsite testing before we could propose a BART control based on it. As is evident in comparing the 50% control level to the higher control level, the cost-effectiveness of DSI worsens (higher $/ton) as the control level increases, and the certainty of any unit attaining that control level decreases. We therefore regard the cost-effectiveness values of the maximum DSI control levels as being useful in a basic comparison of cost-effectiveness between DSI and scrubbers, but we place much less weight on these values. We therefore conclude that given the uncertainty concerning the maximum control level of DSI, the greater control efficiency and resulting visibility benefit offered by scrubbers overrides any possible advantage DSI may hold in cost-effectiveness. Should the affected facilities provide site-specific information to us in their comments that conflicts with this assumption, we will incorporate it into our final decision on SO_2 BART and potentially re-evaluate DSI.

As we indicate elsewhere in our proposal, both SDA and wet FGD are mature technologies that are in wide use throughout the United States. We are not aware of any unusual circumstances that exist for any of the sources that would serve to indicate they should not be viewed similarly to these hundreds of previous scrubber retrofits. In comparing wet FGD versus SDA we note that in a number of cases the cost-effectiveness of wet FGD is lower than the cost-effectiveness of SDA. In the remaining cases, we conclude that the incremental cost-effectiveness of wet FGD over SDA, which we review in Section III.C.3.a is reasonable, and the improved control and visibility benefit offered by wet FGD overrides the small penalty in cost-effectiveness FGD has in comparison to SDA. We propose that with the exception of the Harrington units, SO_2 BART for all other coal-fired units should be based on the wet FGD control levels we have used in our BART analyses. We propose that SO_2 BART for the Harrington units should be based on the SDA control levels we have used in our BART analyses. Below we discuss our consideration of the cost-effectiveness and anticipated visibility benefits of controls. See section III.C.5 for additional information on the anticipated visibility benefits from each level of control modeled. See the BART Modeling TSD for a complete summary of our visibility benefit analysis of controls, including modeled benefits and impacts at all Class I areas included in the modeling analyses and additional metrics considered in the assessment of visibility benefits.

CAMx model results shown in the tables below summarize the benefits from the recommended controls at the two Class I areas most impacted by the source or unit in the baseline modeling. The benefit is calculated as the difference between the maximum impact modeled for the baseline and the maximum impact level modeled under the control scenario. Also summarized are the cumulative benefit and the number of days impacted over 0.5 and 1.0 dv. Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario summed across the 15 Class I areas included in the CAMx modeling. The baseline total cumulative number of days over 0.5 (1.0) dv is calculated as the sum of the number of modeled days at each of the 15 Class I area impacted over the threshold in the baseline modeling. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the 15 Class I areas included in the CAMx modeling for the baseline scenario subtracted by the number of days over the threshold for the control scenario. The CALPUFF cumulative model results only consider those Class I areas within the typical range of CALPUFF and not all 15 Class I areas included in the CAMx modeling.

1. Big Brown 1 & 2

In reviewing the Big Brown units, we conclude that the installation of wet FGD will result in very significant visibility benefits. We summarize some of these visibility benefits in the tables below:

TABLE 21—WET FGD VISIBILITY BENEFITS AT BIG BROWN (CALPUFF)

Source	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total cumulative visibility benefit (dv) [1]	Cumulative reduction in number of days above 0.5 dv [2]	Cumulative reduction in number of days above 1.0 dv [2]
Big Brown Units 1 & 2	3.83	3.55	7.38	151.67	101.33

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek and Wichita Mountains.

[2] Using the three years (2001–2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek and Wichita Mountains.

determination of SCR for Hayden Unit 2, later finalized at 77 FR 76871 (December 31, 2012).

[131] 70 FR 39168 (July 6, 2005).

[132] Note for Harrington Unit 062B and Welsh 1, we further limited the maximum DSI control level to that of our calculated SDA control level.

[133] 70 FR 39166 (July 6, 2005).

In evaluating Big Brown, we note there are two Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001–2003 CALPUFF modeling results, we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the two Class I areas that are within the range that CALPUFF is typically used, the 2001–2003 CALPUFF modeling results indicate that wet FGD on both units will eliminate 151.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. DSI operated at 50% control results in approximately half of the visibility benefits in terms of dv benefits at the most impacted Class I areas and about 1/3rd to half the cumulative benefits over the class I areas included in the modeling analysis.

TABLE 22—WET FGD VISIBILITY BENEFITS AT BIG BROWN (CAMX)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total cumulative visibility benefit (dv)[1]	Baseline total cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Big Brown 1	1.909	1.606	12.728	174/44	174/44
Big Brown 2	1.940	1.642	12.924	175/45	175/45
Source	3.542	2.988	24.274	372/170	362/170

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across 15 Class I areas included in the CAMx modeling.
[2] Baseline Total Cumulative number of days over 0.5 (1.0) dv is calculated as the sum of the number of modeled days at each of the 15 Class I area impacted over the threshold.
[3] Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the 15 Class I areas included in the CAMx modeling for the baseline scenario subtracted by the number of days over the threshold for the control scenario.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 1dv at all Class I areas on a unit and source-wide basis, and eliminate all but 10 days across the impacted Class I areas where the source-wide impacts exceeds 0.5 dv. At the most impacted Class I area, wet FGD will on each unit result in visibility improvements of 1.9 dv on the most impacted day. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the CAMx modeling.

We also conclude that wet FGD is very cost-effective for both units at less than $1,200/ton and more cost-effective than DSI. Based on this consideration of the BART factors, we propose that SO_2 BART for Big Brown Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

2. Monticello 1 & 2

Similar to the Big Brown units, the installation of wet FGD at Monticello Units 1 and 2 will result in very significant visibility benefits. We summarize some of these visibility benefits in the tables below:

TABLE 23—WET FGD VISIBILITY BENEFITS AT MONTICELLO (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mountains (dv)	Total cumulative visibility benefit (dv)[1]	Baseline total cumulative number of days over 0.5/1.0 dv[2]	Cumulative reduction in number of days above 1.0 dv[2]
Monticello Units 1, 2 & 3	4.87	2.70	10.25	224.67	164.67

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.
[2] Using the three years (2001–2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Monticello, we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001–2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001–2003 CALPUFF modeling results indicate wet FGD on both units will eliminate 224.6

days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I area and half of the cumulative benefits.

TABLE 24—WET FGD VISIBILITY BENEFITS AT MONTICELLO (CAMX)

Unit	Improvement at Caney Creek (dv)	Improvement at Wichita Mountains (dv)	Total cumulative visibility benefit (dv) [1]	Baseline total cumulative number of days over 0.5/1.0 dv [2]	Reduction in number of days above 0.5/1.0 dv [3]
Monticello 1	3.783	1.989	12.708	197/67	191/67
Monticello 2	3.924	2.003	13.025	192/57	191/57
Source (including unit 3)	8.419	4.962	31.553	520/293	460/278

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across 15 Class I areas included in the CAMx modeling.
[2] Baseline Total Cumulative number of days over 0.5 (1.0) dv is calculated as the sum of the number of modeled days at each of the 15 Class I area impacted over the threshold.
[3] Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the 15 Class I areas included in the CAMx modeling for the baseline scenario subtracted by the number of days over the threshold for the control scenario.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 1 dv at all Class I areas on a unit basis, and eliminate all but 15 days across the impacted Class I areas where the source-wide impacts exceeds 1 dv. We note that source-wide modeled benefits include benefits of 95% control scrubber upgrade on Unit 3. At the most impacted Class I area, wet FGD on each unit will each result in visibility improvements of 3.8–3.9 dv on the most impacted day at Caney Creek and 2 dv visibility benefits at Wichita Mountains. DSI operated at 50% control results in less than half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

The wet FGD cost-effectiveness of $2,718/ton and $3,031/ton are higher than those for Big Brown, but these figures remain well within a range that we have previously found to be acceptable for BART, and we consider the very significant visibility benefits that will result justify the cost of wet FGD at the Monticello Units 1 and 2. The 50% control DSI cost-effectiveness is slightly less than that for wet-FGD, but results in much less visibility benefits. Based on our consideration of the BART factors, we therefore propose that SO_2 BART for Monticello Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

3. Coleto Creek 1

In reviewing Coleto Creek Unit 1, we conclude that in comparison with the Monticello units, the installation of a wet FGD is more cost-effective and results in lesser, but still significant visibility benefits. We summarize some of these visibility benefits in the table below:

TABLE 25—WET FGD VISIBILITY BENEFITS AT COLETO CREEK UNIT 1 (CAMX)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total cumulative visibility benefit (dv) [1]	Baseline total cumulative number of days over 0.5/1.0 dv [2]	Reduction in number of days above 0.5/1.0 dv [3]
Coleto Creek 1	0.668	0.606	5.233	17/0	17/0

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across 15 Class I areas included in the CAMx modeling.
[2] Baseline Total Cumulative number of days over 0.5 (1.0) dv is calculated as the sum of the number of modeled days at each of the 15 Class I area impacted over the threshold.
[3] Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the 15 Class I areas included in the CAMx modeling for the baseline scenario subtracted by the number of days over the threshold for the control scenario.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 0.5 dv at all Class I areas. At the most impacted Class I area, wet FGD will result in visibility improvements of 0.6 or more on the most impacted days at both Caney Creek and the Wichita Mountains. In addition, seven other Class I areas are improved by amounts ranging from 0.356 to 0.531 dv on the maximum impacted days with wet FGD. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 Class I areas included in the modeling.

We also conclude that wet FGD is very cost-effective at $2,127/ton and well within a range that we have previously found to be acceptable and more cost-effective than DSI. We consider the significant visibility benefits that will result justify the cost of wet FGD at the Coleto Creek Unit 1. We therefore propose that SO_2 BART for Coleto Creek Unit 1 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

4. Welsh 1

In reviewing Welsh Unit 1, we conclude that the installation of a wet FGD will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

TABLE 26—WET FGD VISIBILITY BENEFITS AT WELSH UNIT 1 (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mtns. (dv)	Total cumulative visibility benefit (dv) [1]	Cumulative reduction in number of days above 0.5 dv [2]	Cumulative reduction in number of days above 1.0 dv [2]
Welsh 1	0.72	0.41	1.66	56.67	15

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.

[2] Using the three years (2001–2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Welsh we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001–2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001–2003 CALPUFF modeling results indicate wet FGD on both units will eliminate 56.67 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD.

TABLE 27—WET FGD VISIBILITY BENEFITS AT WELSH UNIT 1 (CAMX)

Unit	Improvement at Caney Creek (dv)	Improvement at Mingo Wilderness (dv)	Total cumulative visibility benefit (dv) [1]	Baseline total cumulative number of days over 0.5/1.0 dv [2]	Reduction in number of days above 0.5/1.0 dv [3]
Welsh 1	1.521	0.579	4.683	65/9	60/9
Source (Welsh 1 & 2)	3.754	1.973	13.179	211/72	206/72

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across 15 Class I areas included in the CAMx modeling.

[2] Baseline Total Cumulative number of days over 0.5 (1.0) dv is calculated as the sum of the number of modeled days at each of the 15 Class I area impacted over the threshold.

[3] Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the 15 Class I areas included in the CAMx modeling for the baseline scenario subtracted by the number of days over the threshold for the control scenario.

CAMx modeling results indicate that wet FGD on unit 1 will eliminate all days impacted by the unit over 1 dv at all Class I areas and all but 5 days impacted over 0.5 dv. At the most impacted Class I area, wet FGD on unit 1 will result in visibility improvements of 1.521 dv on the most impacted days at Caney Creek. In addition to the visibility benefits at Caney Creek and Mingo, visibility benefits at two additional Class I areas exceed 0.5 dv. We note that source-wide benefits shown include the benefits from the shutdown of unit 2. In addition, cumulative benefits from wet FGD on unit 1 over all 15 Class I areas exceeds 4.5 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

We conclude that although at $3,824/ton, the cost-effectiveness of wet FGD is higher than for other facilities, it remains within a range that we have previously found to be acceptable. We consider the significant visibility benefits that will result from the installation of wet FGD at Welsh Unit 1 to justify the cost. DSI at 50% control is slightly more cost-effective but results in much less visibility benefit. We therefore propose that SO_2 BART for Welsh Unit 1 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

5. Harrington 061B & 062B

In reviewing Harrington, we conclude that the installation of SDA on Units 061B and 062B will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

TABLE 28—SDA VISIBILITY BENEFITS AT HARRINGTON (CALPUFF)

Source	Improvement at Salt Creek (dv)	Improvement at Wichita Mtns. (dv)	Total cumulative visibility benefit (dv) [1]	Cumulative reduction in number of days above 0.5 dv [2]	Cumulative reduction in number of days above 1.0 dv [2]
Harrington 061B & 062B	0.45	0.74	2.56	53.67	26

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, and Wheeler Peak.

[2] Using the three years (2001–2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, and Wheeler Peak.

In evaluating Harrington we note there are five Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001–2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the five Class I areas that are within the range that CALPUFF is typically used, the 2001–2003 CALPUFF modeling results indicate wet FGD on both units will eliminate 53.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD.

TABLE 29—SDA VISIBILITY BENEFITS AT HARRINGTON (CAMX)

Unit	Improvement at Salt Creek (dv)	Improvement at Wichita Mountains (dv)	Total cumulative visibility benefit (dv) [1]	Baseline total cumulative number of days over 0.5/1.0 dv [2]	Reduction in number of days above 0.5/1.0 dv [3]
Harrington 061B	1.170	0.643	4.832	17/5	11/3
Harrington 062B	1.279	0.723	5.379	17/5	11/3
Source (061B & 0622B)	2.053	1.130	9.329	51/17	37/11

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across 15 Class I areas included in the CAMx modeling.

[2] Baseline Total Cumulative number of days over 0.5 (1.0) dv is calculated as the sum of the number of modeled days at each of the 15 Class I area impacted over the threshold.

[3] Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the 15 Class I areas included in the CAMx modeling for the baseline scenario subtracted by the number of days over the threshold for the control scenario.

CAMx modeling results indicate SDA on these units will eliminate more than half of all days impacted by the units over 1 dv and 0.5 dv at all Class I areas. At the most impacted Class I areas, SDA on each unit will each result in visibility improvements of approximately 1.2 dv on the most impacted days at Salt Creek and 0.6–0.7 dv at Wichita Mountains, reducing the number of days impacted over 0.5 and 1.0 dv at these Class I areas. In addition, cumulative benefits from SDA on both units over all 15 Class I areas exceeds 9.3 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the SDA visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

We also conclude that SDA is cost-effective at $3,904 for Unit 061B and $4,180/ton for Unit 062B and, remains within a range that we have previously found to be acceptable. In contrast to other units we have reviewed, the 50% control DSI cost-effectiveness is much less than that for SDA. However, given the additional large total cumulative visibility benefits that will result from the installation of SDA over DSI at 50% control, we consider SDA to justify the additional cost. We therefore propose that SO_2 BART for Harrington Units 061B and 062B should be based on the installation of SDA at an emission limit of 0.06 lbs/MMBtu based on a 30 BOD.

6. W. A. Parish WAP 5 & 6

In reviewing W A Parish, we conclude that the installation of wet FGD on Units 5 and 6 will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

TABLE 30—WET FGD VISIBILITY BENEFITS AT W A PARISH (CAMX)

Unit	Improvement at Caney Creek (dv)	Improvement at Upper Buffalo (dv)	Total cumulative visibility benefit (dv) [1]	Baseline total cumulative number of days over 0.5/1.0 dv [2]	Reduction in number of days above 0.5/1.0 dv [3]
W A Parish 5	1.518	0.943	8.171	51/9	51/9
W A Parish 6	1.492	0.922	7.979	48/7	48/7
Source (WAP 4, 5 & 6)	2.665	1.760	15.301	163/49	162/49

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across 15 Class I areas included in the CAMx modeling.
[2] Baseline Total Cumulative number of days over 0.5 (1.0) dv is calculated as the sum of the number of modeled days at each of the 15 Class I area impacted over the threshold.
[3] Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the 15 Class I areas included in the CAMx modeling for the baseline scenario subtracted by the number of days over the threshold for the control scenario.

CAMx modeling results indicate that wet FGD on each of these units will eliminate all days impacted by each unit over 1 dv and 0.5 dv at all Class I areas. At the most impacted Class I areas, wet FGD on each unit will each result in visibility improvements of approximately 1.5 dv on the most impacted days at Caney Creek and 0.9 dv at Upper Buffalo. Nine Class I areas have modeled source-wide baseline impacts over 1 dv, and wet FGD on both units results in source-wide improvements of 1 dv or greater on the maximum impacted days at eight of these Class I areas. In addition, cumulative benefits from wet FGD on both units over all 15 Class I areas exceeds 15 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling. We note that source-wide modeling includes a small impact from WAP 4. This unit is gas-fired and was modeled at baseline emissions levels for both the baseline and control case scenarios.

We conclude that wet FGD is cost-effective at $2,417/ton for Unit 5 and $2,259/ton for Unit 6, and remains well within a range that we have previously found to be acceptable. DSI at 50% control is approximately the same cost-effectiveness but results in significantly less visibility benefit. We consider the cost of wet FGD at the W A Parish units to be justified by the significant visibility benefits that will result. We therefore propose that SO_2 BART for W A Parish Units 5 and 6 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

7. J T Deely 1 & 2

In reviewing J T Deely, we conclude that the installation of wet FGD on Units 1 and 2 will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

TABLE 31—WET FGD VISIBILITY BENEFITS AT J T DEELY (CAMX)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total cumulative visibility benefit (dv) [1]	Baseline total cumulative number of days over 0.5/1.0 dv [2]	Reduction in number of days above 0.5/1.0 dv [3]
J T Deely 1	0.487	0.283	4.785	10/0	10/0
J T Deely 2	0.298	0.217	3.650	7/0	7/0
Source (J T Deely 1 & 2, Sommers 1 & 2)	0.699	0.518	8.943	89/13	84/13

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across 15 Class I areas included in the CAMx modeling.
[2] Baseline Total Cumulative number of days over 0.5 (1.0) dv is calculated as the sum of the number of modeled days at each of the 15 Class I area impacted over the threshold.
[3] Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the 15 Class I areas included in the CAMx modeling for the baseline scenario subtracted by the number of days over the threshold for the control scenario.

CAMx modeling results indicate wet FGD on each of these units will eliminate all days impacted by each unit over 0.5 dv at all Class I areas. At the most impacted Class I areas, wet FGD on each unit will each result in visibility improvements of 0.487 dv and 0.298 dv on the most impacted days at Wichita Mountains and 0.283 dv and 0.217 dv at Caney Creek. Larger visibility improvements on the most impacted days are anticipated at other Class I areas. Benefits from wet FGD on unit 1 are 0.583 dv at Big Bend, 0.511 dv at Salt Creek, 0.449 dv at Guadalupe Mountains and Carlsbad Caverns, and 0.475 dv at White Mountains. Benefits from wet FGD on unit 2 are 0.583 dv at Big Bend, 0.441 dv at Salt Creek, 0.354 dv at Guadalupe Mountains and Carlsbad Caverns, and 0.375 dv at White Mountains. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 Class I areas included in the modeling. We note that source-wide modeling includes the impact from Sommers units 1 and 2, and as discussed in the BART Modeling TSD, control case scenarios for these units included benefits from switching to lower sulfur fuel oil. However, these modeled improvements are a small fraction of the total visibility benefits from controls at the source.

We conclude that wet FGD is cost-effective at $3,898/ton for Unit 1 and $3,712/ton for Unit 2, and remains within a range that we have previously found to be acceptable. We consider the cost of wet FGD at the J T Deely units to be justified by the significant visibility benefits that will result at a number of impacted Class I areas. DSI at 50% control is slightly more cost-effective but results in much less visibility benefit. We therefore propose that SO_2 BART for J T Deely Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.[134]

B. SO_2 BART for Coal-fired Units With Underperforming Scrubbers

The BART Guidelines state that underperforming scrubber systems should be evaluated for upgrades.[135] Other than upgrading the existing scrubbers, all of which are wet FGDs, there are no competing control technologies that could be considered for these units. The CALPUFF modeling generated facility-wide impacts and the benefits of the scrubber upgrade on Monticello Unit 3 and the three Martin Lake facilities are included in Table 17 above. The following is a listing of each of the affected units along with the resulting CAMx modeled visibility benefits from upgrading their existing scrubbers:

TABLE 32—VISIBILITY BENEFIT FOR COAL-FIRED UNITS WITH EXISTING SO_2 CONTROLS (CAMX)

Unit	Improvement at most impacted (dv)	Improvement at 2nd most impacted (dv)	Total cumulative visibility benefit (dv)	Reduction in number of days above 0.5 dv at—	Reduction in number of days above 1.0 dv at—
Monticello 3	3.719 (CACR)	1.918 (WIMO)	11.940	200/66	188/66
Martin Lake 1	1.165 (CACR)	1.449 (UPBU)	7.575	160/41	151/40
Martin Lake 2	0.655 (CACR)	1.164 (UPBU)	6.199	150/41	134/39
Martin Lake 3	1.146 (CACR)	1.478 (UPBU)	7.863	173/47	163/46

As we state elsewhere in this proposal, because our cost-effectiveness calculations depend on information claimed by the companies as CBI we cannot present it here, except to note that in all cases, the cost effectiveness was $1,156/ton or less. We conclude that in all cases, scrubber upgrades are very cost-effective and result in very significant visibility benefits, significantly reducing the impacts from these units and reducing the number of days that Class I areas are impacted over 1.0 dv and 0.5 dv. We propose that SO_2 BART for all other coal-fired units with underperforming scrubbers should be based on the wet FGD upgrade control levels we have used in our BART analyses of them.

C. SO_2 BART for Gas-Fired Units That Burn Oil

In analyzing potential controls for those gas-fired units that occasionally burn fuel oil we considered scrubber retrofits and lower sulfur fuel oil. We concluded that the cost-effectiveness of scrubber retrofits for these units were likely very high, and not worth the potential visibility benefit.

We also concluded that the cost-effectiveness of switching to a No. 2 fuel oil with a sulfur content of 0.3% is $11,218/gallon, and the cost-effectiveness of switching to ULSD with a sulfur content of 0.0015% is $8,627/gallon. We further noted that one facility already had a contract in place for ULSD at a lower price than we assumed, which if used in our analysis would result in a cost effectiveness of $3,970/ton. Although the cost-effectiveness of switching to a lower sulfur oil (assuming our price for ULSD of $1.667/gal) is higher than other controls that we have typically required under BART, we note certain mitigating factors.

For instance, arguing against control, our calculated cost-effectiveness values are high in relation to other BART controls we have required in the past. Also, our visibility modeling necessarily utilized the maximum SO_2 emissions over a 24-hour timeframe,[136] resulting in the configuring of our visibility modeling to analyze the maximum short-term potential impacts that could occur when the unit burns fuel oil. However, as we discuss elsewhere in our proposal, these units are primarily gas-fired, and have only occasionally burned fuel oil. Their most recent practices appear to reinforce this trend.

Arguing for control, unlike the wet FGD and SDA scrubbers we have costed in other sections of this TSD, which have large capital costs, we are unaware of any significant capital costs involved in switching fuels. This means the overall annual costs are relatively minor, if the units in question adhere to their historical usages. Also, because the units in question have only occasionally burned fuel oil, they have the option to avoid the cost of fuel switching entirely by not continuing to burn fuel oil and instead relying solely on their primary fuel of natural gas. Lastly, we note that the prevalence of ULSD in the fuel oil market is such that it appears to be gradually replacing most other No. 2 fuel oil applications.[137]

The preamble to the Regional Haze Rule counseled that a one percent sulfur content limitation on fuel oil should be considered as a ''starting point,'' [138] and the existing sulfur content limits are lower than one percent. Considering all of this information, we propose that SO_2 BART for the gas-fired units that occasionally burn fuel oil should be no further control. In so doing, we acknowledge the data quality issues we have discussed concerning these units and we specifically request comments on all aspects of our proposed BART analysis for these units from all interested parties. Based on the comments we receive, we may either finalize our BART determinations for these units as proposed, or we may revise them without a re-proposal.

D. PM BART

We propose to disapprove the portion of the Texas Regional Haze SIP that sought to address the BART requirement for EGUs for PM. We note that all of the coal-fired units are either currently fitted with a baghouse, an ESP and a polishing baghouse, or an ESP. We conclude that the cost of retrofitting the subject units with a baghouse would be extremely high compared to the visibility benefit for any of the units currently fitted with an ESP.

[134] We have read reports that CPS Energy, is planning to retire J T Deely Units 1 and 2 by the end of 2018, but we have no enforceable documents to that effect.

[135] 70 FR 39171 (July 6, 2005).

[136] See the BART Guidelines at 70 FR 39162, July 6, 2005: ''We recommend that States use the 24 hour average actual emission rate from the highest emitting day of the meteorological period modeled, unless this rate reflects periods start-up, shutdown, or malfunction.''

[137] *http://www.eia.gov/todayinenergy/detail.php?id=5890. http://blogs.platts.com/2014/05/07/heating-oil-new-york-sulfur/. http://oilandenergyonline.com/challenges-to-the-northeast-supply-picture/.*

[138] 70 FR at 39134.

Consequently, we propose that PM BART for the coal-fired units is an emission limit of 0.030 lb/MMBtu along with work practice standards. We propose that PM and SO_2 BART for the units that only fire gas be pipeline natural gas. We propose that PM and SO_2 BART for those gas-fired units that occasionally burn fuel oil be the existing permitted fuel oil sulfur content of 0.7% sulfur by weight or pipeline natural gas.

V. Proposed Actions

A. Regional Haze

We are proposing to disapprove the portion of the Texas Regional Haze SIP that sought to address the BART requirement for EGUs for PM. We are proposing to promulgate a FIP as described in this notice and summarized in this section to satisfy the remaining outstanding regional haze requirements that are unmet by the Texas' regional haze SIP and that we did not take action on in our January 5, 2016 final action.[139] Our proposed FIP includes SO_2 and PM BART emission limits for sources in Texas to reduce emissions that contribute to regional haze in Texas' two Class I areas and other nearby Class I areas and make reasonable progress for the first regional haze planning period for Texas' two Class I areas.

1. NO_X BART

As discussed elsewhere in this proposal, we are proposing a FIP to replace Texas' reliance on CAIR with reliance on CSAPR to address the NO_X BART requirements for EGUs. This portion of our proposal is based on: The recent update to the CSAPR rule; [140] and the EPA's finalization of a separate proposed finding that the EPA's actions in response to the D.C. Circuit's remand would not adversely impact our 2012 demonstration that CSAPR is better than BART.[141] We cannot finalize this portion of the proposed FIP unless and until the EPA finalizes the proposed finding that CSAPR continues to be better than BART because finalization of that proposal would allow for reliance on CSAPR participation as an alternative to source-specific EGU BART for NO_X in Texas.

2. SO_2 BART for Coal-Fired Units

We propose that SO_2 BART for the coal-fired units be the following SO_2 emission limits to be met on a 30 Boiler Operating Day (BOD) period:

TABLE 33—PROPOSED SO_2 BART EMISSIONS LIMITS FOR COAL-FIRED UNITS

Unit	Proposed SO_2 emission limit (lbs/MMBtu)
Scrubber Upgrades	
Martin Lake 1	0.12
Martin Lake 2	0.12
Martin Lake 3	0.11
Monticello 3	0.05
Scrubber Retrofits	
Big Brown 1	0.04
Big Brown 2	0.04
Monticello 1	0.04
Monticello 2	0.04
Coleto Creek 1	0.04
Fayette 1	0.04
Fayette 2	0.04
Harrington 061B	0.06
Harrington 062B	0.06
J T Deely 1	0.04
J T Deely 2	0.04
W A Parish 5	0.04
W A Parish 6	0.04
Welsh 1	0.04

We propose that compliance with these limits be within five years of the effective date of our final rule for Big Brown Units 1 and 2; Monticello Units 1 and 2; Coleto Creek Unit 1; Harrington Units 061B and 062B; J T Deely Units 1 and 2; W A Parish Units 5 and 6; and Welsh Unit 1. This is the maximum amount of time allowed under the Regional Haze Rule for BART compliance. We based our cost analysis on the installation of wet FGD and SDA scrubbers for these units, and in the past we have typically required that scrubber retrofits under BART be operational within five years.

We propose that compliance with these limits be within three years of the effective date of our final rule for Martin Lake Units 1, 2, and 3; and Monticello Unit 3. We believe that three years is appropriate for these units, as we based our cost analysis on upgrading the existing wet FGD scrubbers of these units, which we believe to be less complex and time consuming that the construction of a new scrubber.

We propose that compliance with these limits be within one year for Fayette Units 1 and 2. We believe that one year is appropriate for these units because the Fayette units have already demonstrated their ability to meet these emission limits.

3. Potential Process for Alternative Scrubber Upgrade Emission Limits

In our BART FIP TSD, we discuss how we calculated the SO_2 removal efficiency of the units we analyzed for scrubber upgrades. We note that due to a number of factors we could not accurately quantify, our calculations of scrubber efficiency may contain some error. Based on the results of our scrubber upgrade cost analysis, we do not believe that any reasonable error in calculating the true tons of SO_2 removed affects our proposed decision to require emission reductions, as all of the scrubber upgrades we analyzed are cost-effective (low $/ton). In other words, were we to make reasonable adjustments in the tons removed to account for any potential error in our scrubber efficiency calculation, we would still propose to upgrade these SO_2 scrubbers. We believe we have demonstrated that upgrading an underperforming SO_2 scrubber is one of the most cost-effective pollution control upgrades a coal fired power plant can implement to improve the visibility at Class I areas. However, our proposed FIP does specify a SO_2 emission limit that is based on 95% removal in all cases. This is below the upper end of what an upgraded wet SO_2 scrubber can achieve, which is 98–99%, as we have noted in our BART FIP TSD. We believe that a 95% control assumption provides an adequate margin of error for any of the units for which we have proposed scrubber upgrades, such that they should be able to comfortably attain the emission limits we have proposed. However, for the operator of any unit that disagrees with us on this point, we propose the following:

(1) The affected unit should comment why it believes it cannot attain the SO_2 emission limit we have proposed, based on a scrubber upgrade that includes the kinds of improvements (*e.g.,* elimination of bypass, wet stack conversion, installation of trays or rings, upgraded spray headers, upgraded ID fans, using all recycle pumps, etc.) typically included in a scrubber upgrade.

(2) After considering those comments, and responding to all relevant comments in a final rulemaking action, should we still require a scrubber upgrade in our final FIP we will provide the company the following option in the FIP to seek a revised emission limit after taking the following steps:

(a) Install a CEMS at the inlet to the scrubber.

(b) Pre-approval of a scrubber upgrade plan conducted by a third party engineering firm that considers the kinds of improvements (*e.g.,* elimination of bypass, wet stack conversion, installation of trays or rings, upgraded spray headers, upgraded ID fans, using all recycle pumps, etc.) typically performed during a scrubber upgrade. The goal of this plan will be to maximize the unit's overall SO_2 removal efficiency.

[139] 81 FR 296.

[140] 81 FR 74504.

[141] 81 FR 78954.

(c) Installation of the scrubber upgrades.

(d) Pre-approval of a performance testing plan, followed by the performance testing itself.

(e) A pre-approved schedule for 2.a through 2.d.

(f) Should we determine that a revision of the SO_2 emission limit is appropriate, we will have to propose a modification to the BART FIP after it has been promulgated. It should be noted that any proposal to modify the SO_2 emission limit will be based largely on the performance testing and may result in a proposed increase or decrease of that value.

4. SO_2 BART for Gas-fired Units That Burn Oil

We propose that SO_2 BART for the following gas-fired units that occasionally burn fuel oil be the existing permit limits for the sulfur content of the fuel oil:

TABLE 34—PROPOSED BART SO_2 EMISSION LIMITS GAS UNITS THAT OCCASIONALLY BURN OIL

Facility	Fuel Oil Sulfur Content (percent by weight)
Graham 2	0.7
Newman 2*	0.7
Newman 3*	0.7
O W Sommers 1	0.7
O W Sommers 2	0.7
Stryker Creek ST2	0.7
Wilkes 1	0.7

*The Newman Units 2 and 3 are further limited to burning fuel oil for no more than 876 hours per year.

5. PM BART

We propose that PM BART limits for the coal units, Big Brown Units 1 and 2; Monticello Units 1, 2, and 3; Martin Lake Units 1, 2, and 3; Coleto Creek Unit 1; J T Deely Units 1 and 2; W A Parish Units 5 and 6; Welsh Unit 1; Harrington Units 061B and 062B; and Fayette Units 1 and 2 are 0.030 lb/MMBtu and work practice standards, which we present below:

TABLE 35—PM BART EMISSIONS STANDARDS AND WORK PRACTICE STANDARDS

Unit Type	PM BART Proposal
Coal-Fired BART Units	0.03 lb/MMBtu filterable PM Table 3 to Subpart UUUUU
Gas-Fired Only BART Units	Pipeline quality natural gas
Oil-Fired BART Units when not firing natural gas	Fuel Content not to exceed 0.7% sulfur by weight (also SO_2 BART)

We propose that compliance with these emissions standards and work practice standards be the effective date of our final rule, as the affected facilities' should already be meeting them.

We propose that PM and SO_2 BART for the units that only fire gas, Newman Unit 4; W A Parish Unit 4; and Wilkes Units 2 and 3 be pipeline natural gas.

We propose that PM and SO_2 BART for those gas-fired units that occasionally burn fuel oil, Newman Unit 2 and 3; O W Sommers Units 1 and 2; Stryker Creek Unit ST2; and Wilkes Unit 1 be the existing permitted fuel oil sulfur content of 0.7% sulfur by weight.

B. Interstate Visibility Transport

We are proposing to disapprove Texas' SIP revisions addressing interstate visibility transport under CAA section 110(a)(2)(D)(i)(II) for six NAAQS. We further are proposing a FIP to fully address Texas' interstate visibility transport obligations for: (1) 1997 8-hour ozone, (2) 1997 $PM_{2.5}$ (annual and 24 hour), (3) 2006 $PM_{2.5}$ (24-hour), (4) 2008 8-hour ozone, (5) 2010 1-hour NO_2 and (6) 2010 1-hour SO_2. The proposed FIP is based on the finding that our proposed action to fully address the Texas Regional Haze BART program is adequate to ensure that emissions from Texas do not interfere with measures to protect visibility in nearby states in accordance with CAA section 110(a)(2)(D)(i)(II).

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Overview

This proposed action is not a ''significant regulatory action'' under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011). The proposed FIP would not constitute a rule of general applicability, because it only proposes source specific requirements for particular, identified facilities (8 total).

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. Section 3501 *et seq.* Because it does not contain any information collection activities, the Paperwork Reduction Act does not apply. See 5 CFR 1320(c).

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to conduct a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements 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 not-for-profit enterprises, and small governmental jurisdictions. For purposes of assessing the impacts of today's 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 today's proposed rule on small entities, I certify that this action will not have a significant impact on a substantial number of small entities. In making this determination, the impact of concern is any significant adverse economic impact on small entities. An agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, has no net burden or otherwise has a positive economic effect on the small entities subject to the rule. This rule does not impose any requirements or create impacts on small entities. This proposed FIP action under Section 110 of the CAA will not create any new requirement with which small entities must comply. This action, when finalized, will apply to 14 facilities owned by 8 companies, none of which are small entities. Accordingly, it affords no opportunity for the EPA to fashion for small entities less burdensome compliance or reporting requirements or timetables or exemptions from all or part of the rule. The fact that the CAA prescribes that various consequences (*e.g.,* emission limitations) may or will flow from this action does not mean that the EPA either can or must conduct a regulatory flexibility analysis for this action. We have therefore concluded that, this action will have no net regulatory burden for all directly regulated small entities.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on state, local, and Tribal governments and the private sector. Under Section 202 of UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to state, local, and Tribal governments, in the aggregate, or to the private sector, of $100 million or more (adjusted for inflation) in any one year. Before promulgating an EPA rule for which a written statement is needed, Section 205 of UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of Section 205 of UMRA do not apply when they are inconsistent with applicable law. Moreover, Section 205 of UMRA allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments, it must have developed under Section 203 of UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that Title II of UMRA does not apply to this proposed rule. In 2 U.S.C. Section 1502(1) all terms in Title II of UMRA have the meanings set forth in 2 U.S.C. Section 658, which further provides that the terms ''regulation'' and ''rule'' have the meanings set forth in 5 U.S.C. Section 601(2). Under 5 U.S.C. Section 601(2), ''the term 'rule' does not include a rule of particular applicability relating to . . . facilities.'' Because this proposed rule is a rule of particular applicability relating to 12 named facilities, EPA has determined that it is not a ''rule'' for the purposes of Title II of UMRA.

E. Executive Order 13132: Federalism

This proposed action does not have federalism implications. It 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.

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

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.

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 [142] 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. EPA interprets EO 13045 as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under Section 5–501 of the EO has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it is not economically significant as defined in Executive Order 12866, and because the EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. This action is not subject to EO 13045 because it implements specific standards established by Congress in statutes. However, to the extent this proposed rule will limit emissions of SO_2, NO_X, and PM, the rule will have a beneficial effect on children's health by reducing air pollution.

[142] 62 FR 19885 (Apr. 23, 1997).

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

This proposed 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. 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 federal rule limits emissions of NO_X, SO_2, and PM from 14 facilities in Texas.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, 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: December 9, 2016.

Ron Curry,

Regional Administrator, Region 6.

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

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

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

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

Subpart SS—Texas

■ 2. Section 52.2287 is added to read as follows:

§ 52.2287 Best Available Retrofit Requirements (BART) for SO_2 and Particulate Matter and Interstate pollutant transport provisions; What are the FIP requirements for visibility protection?

(a) *Applicability.* The provisions of this section shall apply to each owner or operator, or successive owners or operators, of the coal or natural gas burning equipment designated below.

(b) *Definitions.* All terms used in this part but not defined herein shall have the meaning given them in the CAA 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 that would be emitted to the atmosphere.

Boiler-operating-day means any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit.

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 or natural gas burning equipment designated below.

PM means particulate matter.

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

Unit means one of the natural gas, gas and/or fuel oil, or coal-fired units covered in this section.

(c) *Emissions limitations and compliance dates for SO_2.* The owner/operator of the units listed below shall not emit or cause to be emitted pollutants in excess of the following limitations from the subject unit. Compliance with the requirements of this section is required as listed below unless otherwise indicated by compliance dates contained in specific provisions.

Unit	Proposed SO_2 emission limit (lbs/MMBtu)	Compliance date (from the effective date of the final rule) (years)
Martin Lake 1	0.12	3
Martin Lake 2	0.12	3
Martin Lake 3	0.11	3
Monticello 3	0.05	3
Big Brown 1	0.04	5
Big Brown 2	0.04	5
Monticello 1	0.04	5
Monticello 2	0.04	5
Coleto Creek 1	0.04	5
Fayette 1	0.04	1
Fayette 2	0.04	1
Harrington 061B	0.06	5
Harrington 062B	0.06	5
J T Deely 1	0.04	5
J T Deely 2	0.04	5
W A Parish 5	0.04	5
W A Parish 6	0.04	5
Welsh 1	0.04	5

(d) *Emissions limitations and compliance dates for PM.* The owner/operator of the units listed below shall not emit or cause to be emitted pollutants in excess of the following limitations from the subject unit. Compliance with the requirements of this section is required as listed below unless otherwise indicated by compliance dates contained in specific provisions.

(1) Coal-Fired Units at Big Brown Units 1 and 2; Monticello Units 1, 2, and 3; Martin Lake Units 1, 2, and 3; Coleto Creek Unit 1; J T Deely Units 1 and 2; W A Parish Units 5 and 6; Welsh Unit 1; Harrington Units 061B and 062B; and Fayette Units 1 and 2.

(i) Normal operations: Filterable PM limit of 0.030 lb/MMBtu.

(ii) Work practice standards specified in 40 CFR part 63, subpart UUUUU, Table 3, and using the relevant definitions in 63.10042.

(2) Gas-Fired Units at Newman Unit 4; Wilkes Units 2 and 3; and W A Parish Unit 4 shall burn only pipeline natural gas, as defined in 40 CFR 72.1

(3) Gas-fired units that also burn fuel oil at Graham Unit 2; Newman Units 2 and 3; O W Sommers Units 1 and 2; Stryker Creek Unit ST2; and Wilkes shall burn 0.7% sulfur content fuel or pipeline natural gas, as defined in 40 CFR 72.1.

(4) Compliance for the units included in Section (d) shall be as of the effective date of the final rule.

(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 the units covered under paragraph (c) of this section. 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 or natural gas 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.

(3) Compliance with the PM emission limits for units in paragraph (d)(1) shall be demonstrated by the filterable PM methods specified in 40 CFR part 63, subpart UUUUU, Table 7.

(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 Division, U.S. Environmental Protection Agency, Region 6, to the attention of Mail Code: 6MM, at 1445 Ross Avenue, Suite 1200, Dallas, Texas 75202–2733. For each unit subject to the emissions limitation 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 SO_2 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.

(3) Records for demonstrating compliance with the SO_2 and PM emission limitations in this section shall be maintained for at least five years.

(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.

■ 3. In § 52.2304, paragraph (f) is added to read as follows:

§ 52.2304 Visibility protection.

* * * * *

(f) *Measures addressing disapproval associated with NO_X,* SO_2, and PM. (1) The deficiencies associated with NO_X identified in EPA's disapproval of the regional haze plan submitted by Texas on March 31, 2009, are satisfied by Section 52.2283.

(2) The deficiencies associated with SO_2 and PM identified in EPA's disapproval of the regional haze plan submitted by Texas on March 31, 2009, are satisfied by Section 52.2287.

[FR Doc. 2016–30713 Filed 1–3–17; 8:45 am]

BILLING CODE 6560–50–P