 6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 52, 78, and 97

[EPA-R06-OAR-2016-0611; EPA–HQ–OAR–2016–0598; FRL-9771-01-R6]

Revision and Promulgation of Air Quality Implementation Plans; Texas; Regional Haze Federal Implementation Plan; Disapproval and Need for Error Correction; Denial of Reconsideration of Provisions Governing Alternative to Source-Specific Best Available Retrofit Technology (BART) Determinations

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 withdraw the existing Texas Sulfur Dioxide (SO_2) Trading Program provisions, which constitute the federal implementation plan (FIP) the EPA previously promulgated to address SO_2 Best Available Retrofit Technology (BART) requirements for EGUs in Texas that are not adequately satisfied by the Texas Regional Haze state implementation plan (SIP). In its place, the EPA proposes a FIP that establishes SO_2 limits on 12 Electric Generating Units (EGUs) located at six Texas facilities to fulfill requirements of the Regional Haze Rule for the installation and operation of BART for SO_2. Based on these proposed changes, we also propose to affirm the continued validity of participation in the Cross-State Air Pollution Rule (CSAPR) trading programs as a BART alternative. Therefore, the EPA is proposing to deny a petition for reconsideration of our 2017 determination that states that are participating in CSAPR can continue to rely on CSAPR participation as a BART alternative.

Finally, we are proposing to find that our prior approval of the portion of the Texas Regional Haze SIP that addresses the BART requirement for EGUs for Particulate Matter (PM) was made in error and are proposing to correct that error by proposing to disapprove that portion of the Texas Regional Haze SIP through our authority under the CAA section 110(k)(6), and, as part of a FIP, we are proposing PM BART limits for 12 EGUs located at six Texas facilities.

DATES: Comments must be received on or before **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE *FEDERAL REGISTER*]**.

Virtual Public hearing:

The EPA is holding a virtual public hearing to provide interested parties the opportunity to present data, views, or arguments concerning the proposal. The EPA will hold a virtual public hearing to solicit comments on **[INSERT DATE 15 DAYS AFTER DATE OF PUBLICATION IN THE *FEDERAL REGISTER*]**. The hearing will convene in two sessions. Session 1 will convene at 1:00 p.m. Central Time (CT) and will conclude at 3:00 p.m. CT, or 15 minutes after the last pre-registered presenter in attendance has presented if there are no additional presenters. Session 2 will convene at 4:00 p.m. Central Time (CT) and will conclude at 7:00 p.m. CT, or 15 minutes after the last pre-registered presenter in attendance has presented if there are no additional presenters The EPA will announce further details, including information on how to register for the virtual public hearing, on the virtual public hearing website at https://www.epa.gov/tx/texas-regional-haze-best-available-retrofit-technology-federal-implementation-plan-and-cross. The EPA will begin pre-registering speakers and attendees for the hearing upon publication of this document in the ***Federal Register***. To pre-register to attend or speak at the virtual public hearing, please use the online registration form available at https://www.epa.gov/tx/texas-regional-haze-best-available-retrofit-technology-federal-implementation-plan-and-cross or contact us via email at R6BARTandCSAPRPetition@epa.gov. The last day to pre-register to speak at the hearing will be on **[INSERT DATE 13 DAYS AFTER DATE OF PUBLICATION IN THE *FEDERAL REGISTER*]**. On **[INSERT DATE 14 DAYS AFTER DATE OF PUBLICATION IN THE *FEDERAL REGISTER*]**, the EPA will post a general agenda for the hearing that will list pre-registered speakers in approximate order at https://www.epa.gov/tx/texas-regional-haze-best-available-retrofit-technology-federal-implementation-plan-and-cross. Additionally, requests to speak will be taken on the day of the hearing as time allows.

The EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearing to run either ahead of schedule or behind schedule. Each commenter will have approximately 3 to 5 minutes to provide oral testimony. The EPA encourages commenters to provide the EPA with a copy of their oral testimony electronically by including it in the registration form or emailing it to R6BARTandCSAPRPetition@epa.gov. The EPA may ask clarifying questions during the oral presentations but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral comments and supporting information presented at the virtual public hearing. A transcript of the virtual public hearing, as well as copies of oral presentations submitted to the EPA, will be included in the docket for this action.

The EPA is asking all hearing attendees to pre-register, even those who do not intend to speak. The EPA will send information on how to join the public hearing to pre-registered attendees and speakers.

Please note that any updates made to any aspect of the hearing will be posted online at https://www.epa.gov/tx/texas-regional-haze-best-available-retrofit-technology-federal-implementation-plan-and-cross. While the EPA expects the hearing to go forward as set forth above, please monitor our website or contact us via email at R6BARTandCSAPRPetition@epa.gov to determine if there are any updates. The EPA does not intend to publish a document in the ***Federal Register*** announcing updates.

If you require the services of a translator or a special accommodation such as audio description/closed captioning, please pre-register for the hearing and describe your needs by **[INSERT DATE 7 DAYS AFTER DATE OF PUBLICATION IN THE *FEDERAL REGISTER*]**. The EPA may not be able to arrange accommodations without advance notice.

ADDRESSES: Submit your comments, identified by Docket ID No. **EPA-R06-OAR-2016-0611** to the federal eRulemaking Portal: https://www.regulations.gov/ (our preferred method). For additional submission methods, please contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section.

Instructions: All submissions received must include the Docket ID No. for this rulemaking. Comments received may be posted without change *to* https://www.regulations.gov/, including any personal information provided.

Docket: The docket for this action is available electronically at *https://www.regulations.gov*. Some information in the docket may not be publicly available via the online docket due to docket file size restrictions, such as certain modeling files, or content (*e.g.,* CBI). To request a copy of the modeling files, please send a request via email to R6TXBARTandCSAPRPetition@epa.gov. For questions about a document in the docket please contact individual listed in the FOR FURTHER INFORMATION CONTACT section.

CBI: Do not submit information containing CBI to the EPA through *https://www.regulations.gov.* To submit information claimed as CBI, please contact the individual listed in the FOR FURTHER INFORMATION CONTACT section. Clearly mark the part or all of the information that you claim to be CBI. In addition to one complete version of the comments that includes information claimed as CBI, you must submit a copy of the comments that does not contain the information claimed as CBI directly to the public docket through the procedures outlined in *Instructions* earlier. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 Code of Federal Regulations (CFR) part 2. For the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *https://www2.epa.gov/dockets/commenting-epa-dockets*.

FOR FURTHER INFORMATION CONTACT: Michael Feldman, Air and Radiation Division, SO_2 and Regional Haze Section (ARSH), Environmental Protection Agency, 1201 Elm St., Suite 500 Dallas, TX 75270; telephone number: 214-665-9793; or via email: R6BARTandCSAPRPetition@epa.gov.

SUPPLEMENTARY INFORMATION:

Throughout this document wherever “we,” “us,” or “our” is used, we mean the EPA.

There are two dockets supporting this action, EPA-R06-OAR-2016-0611 and EPA-HQ-OAR-EPA–HQ–OAR–2016–0598. Docket No. EPA-R06-OAR-2016-0611 contains information specific to BART requirements for Texas, including this notice of proposed rulemaking and prior rulemakings related to Texas BART, previous submittals from the state, and the Technical Support Documents for this action. Docket No. EPA–HQ–OAR–2016–0598 contains previous actions and information related to CSAPR as a BART alternative. All comments regarding this proposed action should be made in Docket No. EPA-R06-OAR-2016-0611. For additional submission methods, please email TXBARTandCSAPRPetition@epa.gov.

Table of Contents

I. Executive Summary

The CAA's visibility protection program was created in response to a national goal set by Congress in 1977 to remedy and prevent visibility impairment in certain national parks, such as Grand Canyon National Park, and national wilderness areas, such as the Okefenokee National Wildlife Refuge. Vistas in these areas are often obscured by visibility impairment such as regional haze, which is caused by emissions from numerous sources located over a wide geographic area.

In response to this Congressional directive, the EPA promulgated regulations to address visibility impairment in 1999. These regulations, which are commonly referred to as the Regional Haze Rule, established an iterative process for achieving Congress's national goal by providing for multiple, approximately 10-year "planning periods" in which state air agencies must submit to EPA plans that address sources of visibility-impairing pollution in their states. The first state plans were due in 2007 for the planning period that ended in 2018. The second state plans were due in 2021 for the period that ends in 2028. This proposal focuses on obligations from the first planning period of the regional haze program.

A central element of these first planning period state plans was the requirement for certain older stationary sources to install the Best Available Retrofit Technology (BART) for the purpose of making reasonable progress towards Congress's national goal of eliminating visibility impairment within our nation's most treasured lands. The Regional Haze Rule provided two approaches a state could take to fulfill its BART obligations: (1) conduct source-by-source evaluations for covered sources, or (2) implement an alternative program, such as an emissions trading program, that achieves greater reasonable progress than source-by-source BART.

One such BART alternative that 19 states have relied on for over a decade to fulfill some or all of their BART obligations with respect to visibility-impairing pollution from power plants is participation in the EPA's Cross-State Air Pollution Rule (CSAPR), an emissions trading program that was promulgated in 2011. Changes to the CSAPR program over the years, particularly with respect to the status of the State of Texas, have required the EPA to reexamine on several occasions whether the program continues to achieve greater reasonable progress than source-by-source BART for participating states. Most recently, after removing Texas from certain aspects of the CSAPR program, the EPA reaffirmed the viability of the CSAPR program as a BART alternative in 2017 and then again in 2020 when the EPA denied a petition for reconsideration of the 2017 reaffirmation.

Texas submitted its first state plan to address regional haze in 2009, relying at that time on the now-defunct predecessor program to CSAPR to satisfy the BART requirement for its power plants.[1] The EPA disapproved this portion of Texas's plan in 2012. Texas is home to numerous power plants, many of which operate without modern pollution controls. As a result, several of these plants are among the highest emitters of visibility-impairing pollutants, such as sulfur dioxide (SO_2), in the nation. These emissions cause or contribute to visibility impairment in such iconic places as Big Bend National Park and Guadalupe Mountains National Park in Texas, Salt Creek Wilderness Area in New Mexico, Caney Creek Wilderness Area in Arkansas, and Wichita Mountains Wilderness Area in Oklahoma. In 2017, the EPA proposed to address the

[1] *https://www.tceq.texas.gov/airquality/sip/bart/haze_sip.html.*

gap in Texas's plan by, among other things, requiring source-by-source BART controls for SO_2 emissions from covered sources that would have significantly reduced these emissions. The EPA never finalized this proposal, however. Instead, in 2017 (and again in 2020), the EPA promulgated an intrastate trading program to govern SO_2 emissions from Texas power plants, based on a finding that the program would achieve greater reasonable progress than source-by-source BART even though the program would allow for increases in SO_2 emissions (and thus increased visibility impairment) instead of emission reductions.

This proposal seeks to address both the BART requirements for Texas's power plants and an outstanding petition that once again calls into question the continued viability of the CSPAR program as a BART alternative for participating states due to the status of Texas, and the complicated interactions between these two regulatory regimes. Specifically, the EPA is proposing to withdraw the intrastate trading program on the basis that it does not achieve greater reasonable progress than source-by-source BART. In its place, the EPA is proposing to promulgate source-by-source BART emission limits for covered sources in Texas. If finalized, these emission limits would reduce emissions from these sources by more than 80,000 tons of SO_2 emissions, improving visibility across a wide range of the nation's most scenic vistas. In addition, the EPA is proposing that these changes to the Texas plan, if finalized, would allow the EPA to once again reaffirm that the CSAPR program remains a viable BART alternative for the 19 participating states. On that basis, the EPA is proposing to deny the outstanding petition seeking to end these states' longstanding reliance on the CSAPR program to satisfy their BART obligations for power plants.

II. Background

A. Regional Haze

Regional haze is visibility impairment that is produced by a multitude of sources and activities which are located across a broad geographic area. These sources and activities emit fine particulate matter ($PM_{2.5}$) (*e.g.,* sulfates, nitrates, organic carbon, elemental carbon, and soil dust) and its 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, in addition to direct sources of PM 2.5, impairs visibility by scattering and absorbing light. Visibility impairment (*i.e.,* light scattering) reduces the clarity, color, and visible distance that one can see. $PM_{2.5}$ can also cause serious health effects (including premature death, heart attacks, irregular heartbeat, aggravated asthma, decreased lung function, and increased respiratory symptoms) and mortality in humans, and contributes to environmental effects such as acid deposition and eutrophication.

In section 169A of the 1977 Amendments to the Clean Air Act (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, anthropogenic impairment of visibility in 156 national parks and wilderness areas designated as mandatory Class I areas.[2] Congress added section 169B to the CAA in 1990 to address regional haze issues, and the EPA promulgated the Regional Haze Rule (RHR),

[2] Areas designated as mandatory Class I areas consist of National Parks exceeding 6,000 acres, wilderness areas and national memorial parks exceeding 5,000 acres, and all international parks that were in existence on August 7, 1977. 42 U.S.C. 7472(a). In accordance with section 169A of the CAA, the 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."

codified at 40 CFR 51.308,[3] on July 1, 1999.[4] The RHR established a requirement to submit a regional haze SIP, which applies to all 50 states, the District of Columbia, and the Virgin Islands.[5]

To address regional haze visibility impairment, the RHR established an iterative planning process that requires states in which Class I areas are located and states from which emissions may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I area to periodically submit SIP revisions to address regional haze visibility impairment.[6] Under the CAA, each SIP submission must contain "a long-term (ten to fifteen years) strategy for making reasonable progress toward meeting the national goal," and the initial round of SIP submissions also had to address the statutory requirement that certain older, larger sources of visibility-impairing pollutants install and operate the Best Available Retrofit Technology (BART), as discussed further in Section II.B.[7] States' first regional haze SIPs were due by December 17, 2007, with subsequent SIP submissions containing revised long-term strategies originally due July 31, 2018, and every ten years thereafter.[8]

B. BART

[3] In addition to the generally applicable regional haze provisions at 40 CFR 51.308, the EPA also promulgated regulations specific to addressing regional haze visibility impairment in Class I areas on the Colorado Plateau at 40 CFR 51.309. The latter regulations are not relevant here.
[4] *See* 64 FR 35714 (July 1, 1999). On January 10, 2017, the EPA promulgated revisions to the RHR that apply for the second and subsequent implementation periods. *See* 82 FR 3078 (Jan. 10, 2017).
[5] 40 CFR 51.300(b).
[6] *See* 42 U.S.C. 7491(b)(2); 40 CFR 51.308(b) and (f); see also 64 FR 35768 (July 1, 1999). The EPA established in the RHR that all states either have Class I areas within their borders or "contain sources whose emissions are reasonably anticipated to contribute to regional haze in a Class I area;" therefore, all states must submit regional haze SIPs. *See* 64 FR 35721. In addition to each of the 50 states, the EPA also concluded that the Virgin Islands and District of Columbia contain a Class I area and/or contain sources whose emissions are reasonably anticipated to contribute regional haze in a Class I area. *See* 40 CFR 51.300(b) and (d)(3).
[7] *See* 42 U.S.C. 7491(b)(2)(A); 40 CFR 51.308(d) and (e).
[8] *See* 40 CFR 51.308(b). The 2017 RHR revisions changed the second period SIP due date from July 31, 2018, to July 31, 2021, and maintained the existing schedules for the subsequent implementation periods. *See* 40 CFR 51.308(f).

Section 169A of the CAA directs states to evaluate the use of retrofit controls at certain larger, older stationary sources to address visibility impacts from these sources, whose emissions are often uncontrolled or poorly controlled. Specifically, section 169A(b)(2) of the CAA requires states to revise their SIPs to contain such measures as may be necessary to make reasonable progress towards the national visibility goal, including a requirement that certain categories of existing major stationary sources built between 1962 and 1977 procure, install, and operate BART as determined by the state applying five statutory factors. On July 6, 2005, the EPA published the *Guidelines for BART Determinations Under the Regional Haze Rule* at Appendix Y to 40 CFR part 51 (BART Guidelines) to assist states in the BART evaluation process. Under the RHR and the BART Guidelines, the BART evaluation process consists of three steps: (1) An identification of all BART-eligible sources in the state, (2) an assessment of whether the BART-eligible sources are subject to BART (based on a determination that each source or sources may reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area), and (3) a determination of an emission limit reflecting BART after applying the five statutory BART factors.[9] In applying the BART factors for a fossil fuel-fired electric generating plant with a total generating capacity in excess of 750 megawatts, a state must use the approach set forth in the BART Guidelines.[10] A state is generally encouraged, but not required, to follow the BART Guidelines for other types of sources.[11]

States must make source-specific BART determinations for all “BART-eligible” sources determined to be subject to BART. However, as an alternative to making these “source-specific” BART determinations, states may adopt an emissions trading program or other alternative

---

[9] *See generally* 40 CFR 51.308(e)(1); 40 CFR part 51, Appendix Y.
[10] 42 U.S.C. 7491(b); 40 CFR 51.308(e)(1)(ii)(B).
[11] *See* 40 CFR part 51, Appendix Y. For additional details regarding the three steps of the BART evaluation process, *see, e.g.,* 85 FR 47134, 47136–37 (August 4, 2020).

program for all or a portion of their BART-eligible sources, so long as the alternative achieves greater reasonable progress towards improving visibility than BART would for those sources, and the alternative meets certain other requirements. Several options are available for making BART-alternative demonstrations, and these are discussed in greater detail in Section IV.B and Section V.[12]

States generally undertook the BART determination process during the regional haze program's first implementation period. While the BART requirement is considered a one-time requirement, BART-eligible sources, including sources found subject to BART and for which a BART emission limit was established, may need to be re-assessed for additional controls in future implementation periods under the CAA's reasonable progress provisions. Thus, the EPA has stated that States should treat BART-eligible sources the same as other reasonable progress sources going forward.[13]

C. Previous Actions Related to Texas BART and "CSAPR Better-than-BART"

The procedural history leading up to this proposed action is set forth in detail in this section. On March 31, 2009, Texas submitted a regional haze SIP (the 2009 Regional Haze SIP) to the EPA that included reliance on Texas's participation in trading programs under the Clean Air Interstate Rule (CAIR) as an alternative to BART for SO_2 and NO_X emissions from Electric Generating Units (EGUs).[14] This reliance was consistent with the EPA's regulations at the time that Texas developed its 2009 Regional Haze SIP.[15] However, at the time Texas submitted its SIP to the EPA, the D.C. Circuit had remanded CAIR (without vacatur).[16] The court left CAIR

---

[12] *See generally* 40 CFR 51.308(e)(2)-(4).
[13] *See* 81 FR 26942, 26947 (May 4, 2016).
[14] CAIR required certain states, including Texas, to reduce emissions of SO_2 and NO_X that contribute significantly to downwind nonattainment of the 1997 NAAQS for fine particulate matter and ozone. *See* 70 FR 25152 (May 12, 2005).
[15] *See* 70 FR 39104 (July 6, 2005).
[16] *See North Carolina* v. *EPA,* 531 F.3d 896 (D.C. Cir. 2008), *as modified,* 550 F.3d 1176 (D.C. Cir. 2008).

and our 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. The EPA promulgated the Cross-State Air Pollution Rule (CSAPR) to replace CAIR in 2011[17] (and revised it in 2012).[18] CSAPR established FIP requirements for sources in a number of states, including Texas, to address the states' interstate transport obligation under CAA section 110(a)(2)(D)(i)(I). CSAPR addresses interstate transport of $PM_{2.5}$ and ozone by requiring affected EGUs in these states to participate in one or more of the CSAPR trading programs, which establish emissions budgets that apply to the EGUs' collective annual emissions of SO_2 and NO_X, as well as emissions of NO_X during ozone season.[19]

Following the issuance of CSAPR, the EPA determined that CSAPR would achieve greater reasonable progress towards improving visibility than would source-specific BART in CSAPR states (a determination often referred to as "CSAPR Better-than-BART").[20] In the EPA's 2012 action promulgating CSAPR-Better-than-BART, the EPA used air quality modeling to show that CSAPR met the two-pronged numerical test for a BART alternative under 40 CFR 51.308(e)(3).[21] In the same action, we revised the Regional Haze Rule to allow states whose sources participate in the CSAPR trading programs to rely on such participation in lieu of requiring BART-eligible EGUs in the state to meet source-specific emission limits reflective of BART controls as to the relevant pollutant. In addition to allowing states to rely on CSAPR to address BART requirements, the EPA issued limited disapprovals of a number of states' regional

[17] Federal Implementation Plans; Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals, 76 FR 48208 (Aug. 8, 2011).
[18] CSAPR was amended three times in 2011 and 2012 to add five states to the seasonal NO_X program and to increase certain state budgets. 76 FR 80760 (December 27, 2011); 77 FR 10324 (February 21, 2012); 77 FR 34830 (June 12, 2012).
[19] Ozone season for CSAPR purposes is May 1 through September 30.
[20] 77 FR 33642 (June 7, 2012). This determination was upheld by the D.C. Circuit. *See Util. Air Regulatory Grp. v. EPA,* 885 F.3d 714 (D.C. Cir. 2018).
[21] *See generally* 77 FR 33642 (June 7, 2012).

haze SIPs, including the 2009 Regional Haze SIP submittal from Texas, due to the states' reliance on CAIR, which had been replaced by CSAPR.[22] The EPA did not immediately promulgate a FIP to address those aspects of the 2009 Regional Haze SIP submittal from Texas subject to the limited disapproval in order to allow more time for the EPA to assess the remaining elements of the SIP.

In December 2014, we proposed an action to address the remaining regional haze obligations for Texas.[23] In that action, we proposed, among other things, to rely on our CSAPR FIP requiring Texas sources' participation in the CSAPR trading programs to satisfy the NO_X and SO_2 BART requirements for Texas's BART-eligible EGUs consistent with the 2012 revisions to the Regional Haze Rule. We also proposed to approve the portions of the 2009 Texas Regional Haze SIP addressing PM BART requirements for the state's BART-eligible EGUs. Before that proposed rule was finalized, however, the D.C. Circuit issued a decision on a number of challenges to CSAPR, denying most claims, but remanding the CSAPR SO_2 and/or seasonal NO_X emissions budgets of several states to the EPA for reconsideration, including the Phase 2 SO_2 and seasonal NO_X budgets for Texas.[24] Due to the uncertainty arising from the remand of Texas's CSAPR budgets, we did not finalize our December 2014 proposal to rely on CSAPR to satisfy the SO_2 and NO_X BART requirements for Texas EGUs.[25] Additionally,

[22] *Id.*
[23] 79 FR 74818 (Dec. 16, 2014).
[24] *EME Homer City Generation, L.P.* v. *EPA (EME Homer City II),* 795 F.3d 118, 132 (D.C. Cir. 2015). In 2012, several state, industry, and other petitioners challenged CSAPR in the D.C. Circuit, which stayed and then vacated the rule, ruling on only a subset of petitioners' claims. *See EME Homer City Generation, L.P. v. EPA*, 696 F.3d 7 (D.C. Cir. 2012). However, in April 2014 the Supreme Court reversed the vacatur and remanded to the D.C. Circuit for resolution of petitioners' remaining claims. *See EPA* v. *EME Homer City Generation, L.P.,*572 U.S. 489 (2014). Following the Supreme Court remand, the D.C. Circuit conducted further proceedings to address petitioners' remaining claims. In July 2015, the court issued a decision denying most of the claims but remanding the Phase 2 SO_2 emissions budgets for Alabama, Georgia, South Carolina, and Texas and the Phase 2 ozone-season NO_X budgets for eleven states to the EPA for reconsideration.
[25] 81 FR 296 (Jan. 5, 2016).

because our proposed action on the PM BART provisions for EGUs was dependent on how SO_2 and NO_X BART were satisfied, we did not take final action on the PM BART elements of the 2009 Texas Regional Haze SIP.[26]

On October 26, 2016, the EPA finalized an update to CSAPR to address the interstate transport requirements of CAA section 110(a)(2)(D)(i)(I) with respect to the 2008 ozone NAAQS (CSAPR Update).[27] The EPA also responded to the D.C. Circuit's remand in *EME Homer City II* of certain CSAPR seasonal NO_X budgets in that action.[28] As to Texas, the EPA withdrew Texas's seasonal NO_X budget finalized in CSAPR to address the 1997 ozone NAAQS. However, in that same action, the EPA promulgated a FIP with a revised seasonal NO_X budget for Texas to address the 2008 ozone NAAQS.[29] Accordingly, Texas sources remain subject to CSAPR seasonal NO_X requirements.

On November 10, 2016, in response to the D.C. Circuit's remand in *EME Homer II* of Texas's CSAPR SO_2 budget, we proposed to withdraw the FIP provisions that required EGUs in Texas to participate in the CSAPR trading programs for annual emissions of SO_2 and NO_X.[30] The EPA indicated that if the withdrawal was finalized, Texas would no longer be eligible under 40 CFR 51.308(e)(4) to rely on participation of its EGUs in a CSAPR trading program as an

[26] In January 2016, we finalized action on the remaining aspects of the December 2014 proposal. This final action disapproved, among other things Texas's reasonable progress analysis and Texas's long-term strategy. The EPA promulgated a FIP establishing a new long-term strategy that consisted of SO_2 emission limits for 15 coal-fired EGUs at eight power plants. 81 FR 296, 302 (Jan. 5, 2016). That rulemaking was judicially challenged, however, and in July 2016, the Fifth Circuit granted the petitioners' motion to stay the rule pending review. Texas v. EPA, 829 F.3d 405 (5th Cir. 2016). On March 22, 2017, following the submittal of a request by the EPA for a voluntary remand of the parts of the rule under challenge, the Fifth Circuit Court of Appeals remanded the rule in its entirety. (In this rulemaking, we are not addressing those remanded requirements.) March 22, 2017, Order, *Texas* v. *EPA,* 829 F.3d 405 (5th Cir. 2016) (No. 16-60118).
[27] 81 FR 74504 (Oct. 26, 2016).
[28] *See generally EME Homer City II,* 795 F.3d 118, (D.C. Cir. 2015).
[29] 81 FR 74504, 74524–25.
[30] 81 FR 78954 (Nov. 10, 2016).

alternative to source-specific SO_2 BART determinations.[31] We also proposed to reaffirm the EPA's 2012 analytical demonstration that CSAPR provides greater reasonable progress than BART despite the changes in CSAPR's geographic scope to address the *EME Homer City II* remand, including removal of Texas's EGUs from the CSAPR trading program for SO_2 emissions.[32] On September 29, 2017, we finalized the withdrawal of the FIP provisions for annual emissions of SO_2 and NO_X for EGUs in Texas[33] and affirmed our proposed finding that the EPA's 2012 analytical demonstration remains valid and that participation in the CSAPR trading programs as amended continues to meet the Regional Haze Rule's criteria for an alternative to BART.[34] (We refer to this as the "2017 Affirmation of CSAPR Better-than-BART" throughout this notice.) In the September 29, 2017, final rule we evaluated the potential emissions shifting that could occur due to the withdrawal of Texas from the CSAPR trading program for SO_2 emissions. Based on this evaluation, we determined that an increase in emissions in the remaining CSAPR states participating in the SO_2 trading program would be more than offset by the favorable visibility impacts brought about by the reduced emissions in Texas under presumptive source-specific SO_2 BART for the state's BART-eligible EGUs.[35] As discussed later in this section, certain environmental organizations filed a petition for reconsideration of this affirmation in November 2017.

On January 4, 2017, we proposed a FIP to address the BART requirements for Texas's BART-eligible EGUs. With respect to NO_X, we proposed to replace the 2009 Regional Haze

---

[31] *Id.* at 78956. The EPA also noted that because Texas EGUs would continue to participate in a CSAPR trading program for ozone-season NO_X emissions, Texas would still be eligible under 40 CFR 51.308(e)(4) to rely on CSAPR participation as an alternative to source-specific NO_X BART determinations for the covered sources. 81 FR at 78962.
[32] *Id.*
[33] Texas continues to participate in CSAPR for ozone season NO_X. See final action signed September 21, 2017, available at *regulations.gov* in Docket No. EPA–HQ–OAR–2016–0598.
[34] 82 FR 45481 (September 29, 2017).
[35] *Id.* at 45493-94.

SIP's reliance on CAIR with reliance on our CSAPR FIP to address the NO_X BART requirements for EGUs.[36] This portion of our proposal was based on the CSAPR Update and our separate November 10, 2016, proposed finding that the EPA's actions in response to the D.C. Circuit's remand would not adversely impact our 2012 demonstration that participation in the CSAPR trading programs meets the Regional Haze Rule's criteria for alternatives to BART.[37] We noted that we could not finalize this portion of our proposed FIP to address the NO_X BART requirements for EGUs unless and until we finalized our proposed finding that CSAPR was still better than BART.[38] (This predicate finding was finalized on September 29, 2017.)

The January 4, 2017, proposed action addressing the SO_2 BART requirements for Texas EGUs acknowledged that Texas sources would no longer be participating in the CSAPR program for SO_2, and therefore, the remaining unfulfilled BART requirements for Texas's BART-eligible EGUs would need to be fulfilled by either an approved SIP or an EPA-issued FIP. The EPA proposed to satisfy these requirements through a BART FIP, which addressed the identification of BART-eligible EGU sources, screening to identify which BART-eligible sources are "subject-to-BART" (*i.e.*, may reasonably be anticipated to cause or contribute to any impairment of visibility in any Class I area), and source-by-source determinations of SO_2 BART controls as appropriate. We proposed SO_2 emission limits on 29 EGUs located at 14 facilities.

In the January 2017 proposal, we also proposed to disapprove the portion of the 2009 Texas Regional Haze SIP that made BART determinations for PM from EGUs, on the grounds that the demonstration in the 2009 Texas Regional Haze SIP relied on underlying assumptions as to how the SO_2 and NO_X BART requirements for EGUs were being met that were no longer

[36] 82 FR 912, 914–15 (Jan. 4, 2017).
[37] 81 FR 74504 (Nov. 10, 2016).
[38] 82 FR 912, 915 (Jan. 4, 2017).

valid with the proposed source-specific SO_2 requirements.[39] The 2009 Texas Regional Haze SIP included a pollutant-specific screening analysis for PM to demonstrate that Texas EGUs were not subject to BART for PM. In a 2006 guidance document,[40] the EPA stated that pollutant-specific screening can be appropriate where a state is relying on a BART alternative to address both NO_X and SO_2 BART. While we previously proposed to approve the EGU BART determinations for PM in the 2009 Texas Regional Haze SIP back in 2014, at that time, CSAPR was an appropriate alternative for SO_2 and NO_X BART requirements for EGUs. With the proposal to promulgate source-specific SO_2 BART requirements, however, SO_2 BART would no longer be addressed by a BART alternative. Thus, pollutant-specific screening for PM was no longer appropriate. To address PM BART requirements, we proposed to promulgate source-specific PM BART requirements, which generally were based on existing practices and control capabilities for those EGUs that we proposed to find subject to BART. For coal-fired units, we proposed PM BART limits consistent with PM emission limits in the Mercury and Air Toxics Standards (MATS) rule; for gas-fired units, we proposed PM BART would be satisfied by making the burning of pipeline-quality gas federally enforceable; and for oil-fired units, we proposed that fuel-content requirements for SO_2 BART would also satisfy PM BART.[41]

[39] In the 2009 Regional Haze Texas SIP, emissions of both SO_2 and NO_X from Texas's BART-eligible EGUs were covered by participation in trading programs, which allowed Texas to conduct a screening analysis of the visibility impacts from PM emissions from such units in isolation. However, modeling on a pollutant specific basis for PM is appropriate only in the narrow circumstance of reliance on BART alternatives to satisfy both NO_X and SO_2 BART. Due to the complexity and nonlinear nature of atmospheric chemistry and chemical transformation among pollutants, the 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.

[40] *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.

[41] 82 FR at 936.

The EPA received public comments on this 2017 proposal encouraging the agency to consider other potentially viable methods of implementing a BART alternative for SO_2 in Texas, rather than finalizing source-specific BART limits. Specifically, some commenters suggested to the EPA the concept of a trading program as a BART alternative to satisfy SO_2 BART requirements. After considering these and other public comments, rather than finalizing source-specific BART limits for subject-to-BART EGUs in Texas, we issued a final action on October 17, 2017, that addressed SO_2 BART requirements for all BART-eligible coal-fired units and a number of BART-eligible gas- or gas/fuel oil-fired units through a BART alternative for SO_2—specifically, a new intrastate trading program (Texas SO_2 Trading Program). The remaining BART-eligible EGUs not covered by the Texas SO_2 Trading Program were determined to be not subject to BART based on screening methods as described in our January 2017 proposed rule and the associated BART Screening technical support document (BART Screening TSD) for that action.[42]

At the time, the EPA modeled the Texas SO_2 Trading Program after the CSAPR SO_2 trading program. We determined that the Texas SO_2 Trading Program would achieve similar emission reductions to CSAPR had the state continued to be subject to the CSAPR trading program through a FIP or SIP. As such, we concluded that the Texas program satisfied the clear-weight-of-evidence test requirements for a BART alternative under 40 CFR 51.308(e)(2).[43] As finalized in October 2017, the Texas SO_2 Trading Program established an annual trading program budget of 238,393 tons allocated to the covered units, as well as a Supplemental

[42] *See* document in regulations.gov at docket identification number EPA–R06–OAR–2016–0611–0005.
[43] 82 FR 48324, 48329-30, 48357 (Oct. 17, 2017). The EPA initially determined that the Texas SO_2 Trading Program achieved greater reasonable progress than source-specific BART under the clear-weight-of-evidence test in 40 CFR 51.308(e)(2), relying on the EPA's national finding that CSAPR provides for greater reasonable progress than BART and the fact that the Texas SO_2 Trading Program would achieve similar emission reductions to CSAPR in Texas. *See* 82 FR at 48329-30.

Allowance Pool budget of 10,000 tons, for a total of up to 248,393 allowances potentially available in each year on average.[44] The Texas SO_2 Trading Program allowed "banking" of allowances for use in future years, similar to the CSAPR trading programs, but unlike the CSAPR programs, did not impose an "assurance level" above which annual emissions would be penalized via a higher allowance-surrender ratio. The Texas SO_2 Trading Program did not include all EGUs that would have been subject to CSAPR, but the EPA concluded that potential annual emissions from the excluded units were relatively small (i.e., less than 27,500 tons) and would not undermine its overall conclusion that the Texas SO_2 Trading Program was essentially equivalent in design and stringency to the CSAPR program.[45] In reaching that conclusion, the EPA compared the annual average emission limit of 248,393 tons under the Texas SO_2 Trading Program (combined with estimated emissions for the non-covered EGUs) to a benchmark figure of 317,100 tons of annual SO_2 emissions evaluated for EGUs in Texas in the 2012 CSAPR Better-Than-BART analysis.[46]

In our final action on October 17, 2017, we also finalized our January 2017 proposed determination that Texas's participation in CSAPR's trading program for ozone-season NO_X qualifies as an alternative to source-specific NO_X BART. Because Texas continues to participate in CSAPR's trading program for ozone-season NO_X, we are not reopening this determination in this action. Finally, because both NO_X and SO_2 were now once again addressed by a BART alternative, we approved Texas's 2009 Regional Haze SIP's determination, based on a pollutant-specific screening analysis, that Texas's EGUs are not subject to BART for PM.

[44] *Id.* at 48358.
[45] *Id.*
[46] *Id.* at 48359-60.

On November 28, 2017, Sierra Club and the National Parks Conservation Association (NPCA) submitted a petition for partial reconsideration of our September 2017 finding affirming that CSAPR continues to satisfy requirements as a BART alternative.[47] Among other things, the petitioners alleged that it was impracticable, and indeed impossible, to comment on the relationship between the Texas SO_2 Trading Program and the CSAPR Better-than-BART analysis in the final rule because the EPA did not finalize the Texas SO_2 Trading Program until after the final rule was signed and the EPA had assumed presumptive source-specific SO_2 BART controls in the rulemaking record for the final rule.[48] Petitioners alleged, in particular, that the EPA's emissions shifting analysis accounted for potential increases in emissions in remaining CSAPR states of between 22,300 to 53,000 tons by assuming these emissions would be offset by an estimated 127,300 tons of SO_2 emission reductions in Texas due to presumptive source-specific BART controls.[49] However, these petitioners alleged that this assumption was proven false when the EPA promulgated the Texas SO_2 Trading Program rather than source-specific BART.[50] On this basis, among other things, petitioners sought mandatory reconsideration of the September 29, 2017 action under CAA section 307(d)(7)(B).

On December 15, 2017, the EPA received a separate petition from Sierra Club, NPCA, and the Environmental Defense Fund (EDF) requesting reconsideration of certain aspects of the October 2017 final rule focused mainly on issues related to the Texas SO_2 Trading Program promulgated to address the SO_2 BART requirement for Texas EGUs.[51] In response to the

[47] Sierra Club and National Parks Conservation Association, Petition for Partial Reconsideration of *Interstate Transport of Fine Particulate Matter: Revision of Federal Implementation Plan Requirements for Texas*; Final Rule; 82 FR 45,481 (Sept. 29, 2017); EPA–HQ–OAR –2016–0598; FRL–9968–46–OAR (submitted Nov. 28, 2017).
[48] *Id.* at 8-9.
[49] *Id.* at 13–14.
[50] *Id.*
[51] Sierra Club, National Parks Conservation Association, and Environmental Defense Fund Petition for Reconsideration of *Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate*

December 15, 2017, petition for reconsideration and in light of the change in direction between the EPA's proposed and final actions for SO_2 BART in Texas, we stated that we believed that certain aspects of the October 2017 final rule could benefit from further public comment. Accordingly, on August 27, 2018, the EPA proposed to affirm in most respects the October 2017 final rule, including the Texas SO_2 Trading Program, but solicited public comment on certain issues including whether the Texas SO_2 Trading Program for certain EGUs in Texas met the requirements for an alternative to BART for SO_2 and our approval of Texas's SIP determination that no sources are subject to BART for PM.[52]

On November 14, 2019, partly in response to comments received on its 2018 proposed affirmation, the EPA issued a supplemental proposal to amend certain parts of the Texas SO_2 Trading Program.[53] The supplemental proposal included additional measures such as an assurance level and penalty provisions. Specifically, these provisions imposed a penalty surrender ratio of three-to-one on SO_2 emissions exceeding a specified "assurance level."[54] The notice also proposed a variability limit set at 7 percent of the trading program budget (or 16,668 tons) and a resulting assurance level of 107 percent of the trading program budget (or 255,081 tons[55]) based on the CSAPR methodology establishing such amounts for CSAPR states but

Visibility Transport Federal Implementation Plan (Oct. 17, 2017) EPA–R06–OAR–2016–0611; FRL–9969–07–Region 6 (submitted Dec. 15, 2017).

[52] 83 FR 43586, 43587.

[53] 84 FR 61850 (Nov. 14, 2019).

[54] *Id.* at 61853.

[55] In the final rule signed on June 29, 2020, we adjusted the assurance level to 255,083 tons rather than the 255,081-ton assurance level we proposed in the November 2019 supplemental proposal. 85 FR 49170, 49183 (Aug. 12, 2020).

applied to Texas-specific data.[56] The supplemental proposal also included other minor changes with the goal of strengthening the overall stringency of the program.[57]

On June 29, 2020, in two separate but concurrent actions, former EPA Administrator Andrew Wheeler signed a final rule affirming, with the proposed modifications from the supplemental proposal described above, the Texas SO_2 Trading Program as an alternative to BART for SO_2 for certain sources in Texas and signed a letter denying the petition for reconsideration of the 2017 affirmation of CSAPR Better-than-BART.[58] Along with the denial of the petition, the EPA also published in the docket the "Cross-State Air Pollution Rule (CSAPR) Better Than Best Available Retrofit Technology (BART) Petition for Reconsideration Sensitivity Calculations"[59] to demonstrate that, even accounting for the reduced stringency of the Texas SO_2 Trading Program as compared to source-specific BART in Texas, and assuming a concomitant shift in SO_2 emissions to remaining CSAPR states in the southeastern United States, CSAPR remained a valid BART alternative.

On August 28, 2020, the Sierra Club, NPCA, and Earthjustice submitted a petition for partial reconsideration under CAA section 307(d)(7)(B) of the EPA's 2020 Denial of their November 2017 petition for reconsideration (August 2020 petition).[60] The petitioners alleged that because the EPA presented the updated CSAPR Better-than-BART sensitivity calculations

[56] The increment between a state's emissions budget and its corresponding assurance level is referred to as a "variability limit," because the increment is designed to account for year-to-year variability in electricity generation and associated emissions.
[57] 84 FR at 61855-56.
[58] *See* 85 FR 49170 (Aug. 12, 2020) (affirming the Texas SO_2 Trading Program as an alternative to BART for certain EGU sources in Texas). 85 FR 40286 (July 6, 2020) (providing notice that the agency responded to a petition for partial reconsideration of the 2017 affirmation of CSAPR better than BART).
[59] Docket document ID EPA-HQ-OAR-2016-0598-0034 available at https://www.regulations.gov/docket/EPA-HQ-OAR-2016-0598.
[60] Petition for Partial Reconsideration of Denial of Petition for Reconsideration and Petition for Reconsideration of the Interstate Transport of Fine Particulate Matter: Revision of Federal Implementation Plan Requirements for Texas (Aug. 28, 2020), Docket document ID EPA-HQ-OAR-2016-0598-0041, available in www.regulations.gov.

for the first time in its 2020 denial of the 2017 Petition (and thus they were not afforded an opportunity to comment), and because that updated analysis is of central relevance to the September 2017 Final Rule, the EPA must reconsider both actions under CAA section 307(d)(7)(B).[61] The petitioners alleged that, contrary to the EPA's conclusions in its 2020 Denial, the updated CSAPR Better-than-BART analysis demonstrates that visibility improvement under CSAPR is *not* equal to or greater than visibility improvement under source-specific BART averaged over all 140 Class I areas, or the 60 eastern Class I areas covered by CSAPR.[62] The August 2020 petition will be discussed in further detail in Section V.

On October 13, 2020, we received a separate petition for partial reconsideration from NPCA, Sierra Club, and Earthjustice, on our 2020 final rule affirming that the Texas SO_2 Trading Program is a valid alternative to SO_2 BART requirements for Texas EGUs.[63] In the petition, Petitioner's allege that the EPA presented a corrected sensitivity analysis for the first time on July 6, 2020, the day the EPA published notice of its denial of the 2017 administrative petition for reconsideration of the CSAPR Better-than-BART affirmation and after the EPA signed the final rule affirming the Texas Regional Haze BART FIP. Specifically, the Petitioners alleged that the corrected sensitivity analysis is the "primary evidence" for the EPA's conclusion that the Texas SO_2 Trading Program is a lawful and valid BART alternative for SO_2 under the Regional Haze Rule, and that contrary to the EPA's assertions, the "corrected" analysis reveals that the Texas SO_2 Trading Program does not achieve greater reasonable progress than source-specific BART, and therefore, is arbitrary and contrary to the Clean Air Act and Regional Haze

[61] 2020 Pet. at 8.
[62] 2020 Pet. at 9.
[63] Sierra Club, National Parks Conservation Association, and Earthjustice Petition for Partial Reconsideration of *Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan* EPA–R06–OAR–2016–0611 (dated Oct. 13, 2020).

Rule. Moreover, Petitioners contended that the corrected sensitivity analysis demonstrates that visibility improvement under CSAPR, including the Texas SO_2 Trading Program, is *not* equal to or greater than visibility improvement under source-specific BART averaged over all 140 Class I areas or the 60 eastern Class I areas generally within the states covered under CSAPR. Because the EPA disclosed the updated analysis for the first time on July 6, 2020, the Petitioners argued that the grounds for the objections raised in this petition arose after the period for public comment, which ended on January 13, 2020, for the EPA's supplemental notice of proposed rulemaking (84 Fed. Reg. 61,850 (Nov. 14, 2019)). Thus, Petitioners alleged the petition met the requirements for mandatory reconsideration under CAA section 307(d)(7)(B).

By letter dated June 22, 2021, the EPA acknowledged receipt of the petition for partial reconsideration and, without conceding that the conditions for mandatory reconsideration were necessarily met pursuant to CAA section 307(d)(7)(B), the agency recognized that aspects of this action warrant careful review, and potential modification, to ensure our actions are fully consistent with the requirements of the Clean Air Act and the Regional Haze Rule.[64] The letter stated the EPA's intent to reconsider certain aspects of the Texas Regional Haze BART action, which we are proposing in this action.

D. Consultation with Federal Land Managers (FLMs)

The Regional Haze Rule requires that a state, or the EPA if promulgating a FIP, consult with FLMs before adopting and submitting a required SIP or SIP revision or a required FIP or FIP revision. Under 40 CFR 51.308(i)(2), a state, or the EPA if promulgating a FIP, must

[64] Letter from Joseph Goffman, Acting Assistant Administrator Office of Air and Radiation, Re: Sierra Club and National Parks Conservation Association, Petition for Partial Reconsideration of Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan EPA–R06–OAR–2016–0611 (June 22, 2021) available in Docket ID No. EPA–R06–OAR–2016–0611 or at https://www.epa.gov/system/files/documents/2021-07/tx-rh-bart-fip-response-signed_1.pdf.

provide an opportunity for consultation no less than 60 days prior to holding any public hearing or other public comment opportunity on a SIP or SIP revision, or FIP or FIP revision, for regional haze. The EPA must include a description of how it addressed comments provided by the FLMs when considering a FIP or FIP revision. We consulted with the FLMs (specifically, U.S. Fish and Wildlife Service, U.S. Forest Service, and the National Park Service) on December 6, 2022. During the consultation we provided an overview of our proposed actions. The FLMs signaled support for our proposed action.[65]

III. Overview of Proposed Action

In this notice of proposed rulemaking, the EPA proposes an action with several interrelated components. As more fully explained in the following sections, on reconsideration, and due to concerns that our justification for the Texas SO_2 Trading Program rested on an erroneous interpretation of our BART alternative regulations, we are proposing to withdraw the Texas SO_2 Trading Program and instead propose source-specific BART limits for certain EGUs in Texas. We are proposing to satisfy the Regional Haze Rule's SO_2 BART requirements through conducting a source-specific BART analysis for certain BART-eligible EGU sources identified in this action. Additionally, based on our assessment of the effect of this proposed action with regard to Texas BART (if finalized), we are proposing to re-affirm our 2017 analytical demonstration that CSAPR remains a valid BART alternative. Thus, in this action we propose to deny the 2020 petition for partial reconsideration of our 2020 denial of a petition for reconsideration of that 2017 determination. Finally, we are proposing to make an error correction under CAA section 110(k)(6) with respect to our prior approval of the portion of the 2009 Texas Regional Haze SIP that found that Texas's EGUs are not subject to BART for PM on the

[65] *See* "Texas Regional Haze FLM Consultation 12-6-2022.xls" in the docket for this action.

grounds that our approval relied on underlying assumptions as to how the SO_2 and NO_X BART requirements for EGUs were being met that are no longer valid with the proposed withdrawal of the Texas SO_2 Trading Program. As such, we propose to correct the error by disapproving Texas's 2009 Regional Haze SIP submission related to PM BART and propose to satisfy PM BART by also conducting a source-specific BART analysis for certain BART-eligible EGU sources identified in this action. Unless expressly reopened in this notice, the EPA is not reopening any other prior determinations related to regional haze requirements in the State of Texas.

IV. Withdrawal of the Texas SO_2 Trading Program as a BART Alternative for SO_2

As previously stated, on August 12, 2020, the EPA published a final rule affirming our 2017 final rule that the Texas SO_2 Trading Program, with amendments, satisfied the requirements for a BART alternative for SO_2 under 40 CFR 51.308(e)(2).[66] In this action, we are proposing to find that the basis for the Texas SO_2 Trading Program as a BART alternative rested on an erroneous interpretation of our BART alternative regulations. That interpretation in turn produced an analytical basis for the BART alternative that we now propose to find insufficient and in error. We are proposing to withdraw the Texas SO_2 Trading Program under CAA section 110(k)(6) and our inherent authority to reconsider prior actions.

A. Legal Authority to Withdraw the Texas SO_2 Trading Program

1. The EPA's Error Correction Authority Under CAA 110(k)(6)

The EPA proposes to correct its Texas Regional Haze BART FIP by proposing to withdraw the Texas SO_2 Trading Program and proposing to instead conduct a source-specific BART analysis for the BART-eligible EGUs included in the Texas SO_2 Trading Program. In this

[66] *See generally* 85 FR 49170.

action, we are proposing to find that the Texas SO_2 Trading Program was promulgated on an erroneous basis, constituting an error under CAA section 110(k)(6).

Section 110(k)(6) of the CAA provides the EPA with the authority to make corrections to actions on CAA implementation plans that are subsequently found to be in error. *Ass'n of Irritated Residents v. EPA*, 790 F.3d 934, 948 (9th Cir. 2015) (110(k)(6) is a "broad provision" enacted to provide the EPA with an avenue to correct errors). The key provisions of section 110(k)(6) are that the Administrator has the authority to "determine" that the promulgation of a plan was "in error," and when the Administrator does so, may then revise the action "as appropriate," in the same manner as the prior action.[67] Moreover, CAA section 110(k)(6) "confers discretion on the EPA to decide if and when it will invoke the statute to revise a prior action." 790 F.3d at 948 (section 110(k)(6) grants the "EPA the discretion to decide when to act pursuant to that provision").

While CAA section 110(k)(6) provides the EPA with the authority to correct its own "error," nowhere does this provision or any other provision in the CAA define what qualifies as "error." Thus, the EPA believes that the term should be given its plain language, everyday meaning, which includes all unintentional, incorrect, or wrong actions or mistakes.[68] Under CAA section 110(k)(6), the EPA must make an error determination and provide the "the basis thereof." There is no indication that this is a substantial burden for the Agency to meet. To the contrary, the requirement is met if the EPA clearly articulates the error and basis thereof. *Ass'n of Irritated Residents v. EPA*, 790 F.3d at 948.; *see also* 85 FR 73636, 73638.

2. The EPA's Inherent Authority to Reconsider its Prior Action

[67] *See* 85 FR 73636, 73637 (Nov. 19, 2020).
[68] *See* 85 FR at 73637-38.

In addition to the error correction provision of CAA section 110(k)(6), the EPA also has the inherent administrative authority to withdraw the Texas SO_2 Trading Program and propose in its place to conduct a source-specific BART analysis for the BART-eligible EGUs included in the Texas SO_2 Trading Program. This authority lies in CAA section 301(a), read in conjunction with CAA section 110 and case law holding that an agency has inherent authority to reconsider its prior actions.[69] Section 301(a) authorizes the EPA "to prescribe such regulations as are necessary to carry out the [EPA's] functions" under the CAA. Reconsidering prior rulemakings, when necessary, is part of the "[EPA's] functions" under the CAA—considering the EPA's inherent authority as recognized under the case law to do so—and as a result, CAA section 301(a) confers authority upon the EPA to undertake this rulemaking. Moreover, CAA section 110(c)(1) provides the EPA with the authority to promulgate a FIP where "the Administrator…disapproves a State implementation plan submission in whole or in part." As such, the EPA's authority to promulgate FIPs under the CAA necessarily provides it the inherent authority to amend/withdraw FIPs.[70]

Additionally, it is well-established that the EPA has discretion to revisit existing regulations. Specifically, agencies have inherent authority to reconsider past decisions and to revise, replace, or repeal a decision to the extent permitted by law and supported by a reasoned explanation. *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502, 515 (2009) ("*Fox*"); *Motor Vehicle Manufacturers Ass'n of the United States, Inc.* v. *State Farm Mutual Automobile Insurance Co.,* 463 U.S. 29, 42 (1983) ("*State Farm*"); *see also Encino Motorcars, LLC* v. *Navarro,* 579 U.S. 211, 221-22 (2016).

---

[69] *Trujillo* v. *General Electric Co.,* 621 F.2d 1084, 1086 (10th Cir. 1980) ("Administrative agencies have an inherent authority to reconsider their own decisions, since the power to decide in the first instance carries with it the power to reconsider.")
[70] *See* 76 FR 25177, 25181 (May 2011).

As such, we find that our inherent ability to reconsider past actions also provides us the authority to withdraw the Texas SO_2 Trading Program for the same reasons as under CAA section 110(k)(6), as described in Section IV.B. That is, because the Texas SO_2 Trading Program rested on what we find to be an improper interpretation of our BART alternative regulations, we are proposing to withdraw the program and to conduct a source-specific BART analysis for those EGUs currently participating in the program.

The EPA acknowledges the potential for reliance interests to be affected by our reconsideration of a prior rule. However, the EPA is not aware of any substantial commitment of resources or capital, or that the EGUs covered by the Texas SO_2 Trading Program undertook any significant decisions in reliance on participation in the trading program. The Texas SO_2 Trading Program established an emissions budget that the covered sources were already operating well below. Therefore, the requirements of the Texas SO_2 Trading Program did not cause any sources to invest in new pollution control technology or to undertake any other significant investments. Further, because the Texas SO_2 Trading Program rested on an improper interpretation of our BART alternative regulations, we do not think a reliance interest alone (even if there were such interests) would be sufficient to overcome the need to return to a proper interpretation of our BART regulations and proper implementation of the BART program.

B. Basis for Withdrawing the Texas SO_2 Trading Program

We propose that, in attempting to demonstrate that the Texas SO_2 Trading Program satisfied the BART alternative requirements in 40 CFR 51.308(e)(2), the EPA erroneously relied on its previous determination that the CSAPR trading program is better-than-BART nationwide, when in fact the Texas SO_2 Trading Program was a separate BART alternative program that was not a part of the CSAPR program.[71] Because the Texas SO_2 Trading Program was and is separate and distinct from CSAPR and functioned as an independent BART alternative disconnected from any other BART alternative, we propose that in conducting the comparative analysis required by 51.308(e)(2)(i), the EPA should have compared the visibility benefits of the Texas SO_2 Trading Program in isolation with the visibility benefits of source-specific BART controls for the particular subject-to-BART sources that would have been required in the absence of the BART alternative. We conducted no such comparison in either the 2017 rule originally promulgating the Texas SO_2 Trading Program, nor in the 2020 action affirming the Texas SO_2 Trading Program with certain, minor amendments. For purposes of determining whether it is appropriate to now withdraw the Texas SO_2 Trading Program as a BART alternative, we have conducted an analysis comparing the Texas SO_2 Trading Program to source-specific BART for the relevant EGU BART sources. We propose to find that source-specific BART controls substantially outperform the Texas SO_2 Trading Program in terms of emission reductions and visibility improvement at the Class I areas that are affected by the sources in Texas. As a result of this finding of error, we are proposing to withdraw the Texas SO_2 Trading Program as a BART alternative for SO_2 and propose in its place to conduct a source-specific BART analysis for those BART-eligible EGUs included in the Texas SO_2 Trading Program.

1. BART Alternative Requirements

The Regional Haze Rule's BART provisions generally direct states to identify all BART-eligible sources; determine which of those BART-eligible sources are subject to BART requirements based on whether the sources emit air pollutants that may reasonably be anticipated to cause or contribute to visibility impairment in a Class I area; determine source-specific BART

[71] *See* 82 FR 48324, 48330 (Oct. 17, 2017).

for each source that is subject to BART requirements, based on an analysis taking specified factors into consideration; and include emission limitations reflecting those BART determinations in their SIPs. However, the Regional Haze Rule also provides each state with the flexibility to adopt an allowance trading program or other alternative measure instead of requiring source-specific BART controls, so long as the alternative measure is demonstrated to achieve greater reasonable progress than BART toward the national goal of achieving natural visibility conditions in Class I areas.

States, or the EPA if promulgating a FIP, that opt to rely on an alternative program in lieu of source-specific BART, must meet the requirements under 40 CFR 51.308(e)(2) and, if applicable, (e)(3). These requirements for alternative programs establish the criteria for demonstrating that the alternative program will achieve greater reasonable progress than would be achieved through the installation and operation of BART (i.e., they establish the "better-than-BART" tests) and are fundamental elements of any alternative program. To demonstrate that the alternative program achieves greater reasonable progress than source-specific BART, states, or the EPA if developing a FIP, must demonstrate that the alternative meets the requirements, as applicable, in 40 CFR 51.308(e)(2)(i) through (vi). Separately, under 40 CFR 51.308(e)(4), states whose sources participate in the CSAPR trading program(s) may rely on such programs to satisfy BART as to the relevant pollutants and sources without the need for any additional analysis (discussed in more detail in Section V).

Under 40 CFR 51.308(e)(2), the state, or the EPA, must conduct an analysis of the best system of continuous emission control technology available and the associated emission reductions achievable for each source subject to BART covered by the alternative program, termed a "BART benchmark."[72] Where the alternative program has been designed to meet requirements other than BART, simplifying assumptions may be used to establish a BART benchmark.[73] The BART benchmark is the basis for comparison in the better-than-BART test for BART alternatives. Under 40 CFR 51.308(e)(2)(i)(E), the state or the EPA must provide a determination that the alternative program achieves greater reasonable progress than BART under 40 CFR 51.308(e)(3). 40 CFR 51.308(e)(3), in turn, provides two different avenues, applicable under specific circumstances, for determining whether the BART alternative achieves greater reasonable progress than BART. If the distribution of emissions under the alternative program is not substantially different than under BART, and the alternative program results in greater emissions reductions of each relevant pollutant than BART, then the alternative program may be deemed to achieve greater reasonable progress. On the other hand, if the distribution of emissions is significantly different, the differences in visibility improvement between BART and the alternative program must be determined by conducting dispersion modeling for each impacted Class I area for the best and worst 20 percent of days. This modeling demonstrates "greater reasonable progress" if both of the following criteria are met: (1) Visibility does not decline in any Class I area; and (2) there is overall improvement in visibility when comparing the average differences in visibility conditions between BART and the alternative program across all the affected Class I areas.[74]

Alternatively, pursuant to 40 CFR 51.308(e)(2)(i)(E), a third test is available under which states may show that the BART alternative achieves greater reasonable progress than BART "based on the clear weight of evidence." As stated in the EPA's revisions to the Regional Haze

[72] 40 CFR 51.308(e)(2)(i)(C).
[73] 40 CFR 51.308(e)(2)(i)(C).
[74] 40 CFR 51.308(e)(3).

Rule governing alternatives to source-specific BART determinations, such demonstrations attempt to make use of all available information and data which can inform a decision while recognizing the relative strengths and weaknesses of that information in arriving at the soundest decision possible.[75] Factors which can be used in a weight of evidence determination in this context may include, but are not limited to, future projected emissions levels under the program as compared to under BART, future projected visibility conditions under the two scenarios, the geographic distribution of sources likely to reduce or increase emissions under the program as compared to BART sources, monitoring data and emissions inventories, and sensitivity analyses of any models used. This array of information and other relevant data may be of sufficient quality to inform the comparison of visibility impacts between BART and the alternative program. In showing that an alternative program is better than BART and when there is confidence that the difference in visibility impacts between BART and the alternative scenarios are expected to be large enough, a weight of evidence comparison may be warranted in making the comparison.

Under 40 CFR 51.308(e)(2)(iii) and (iv), all emission reductions for the alternative program must take place during the period of the first long-term strategy (i.e., the first planning period) for regional haze and all the emission reductions resulting from the alternative program must be surplus to those reductions resulting from measures adopted to meet requirements of the CAA as of the baseline date of the SIP.

2. The EPA Inappropriately Relied on CSAPR When Promulgating and Affirming the Texas SO_2 Trading Program in 2017 and 2020.

[75] 71 FR 60612, 60622 (Oct. 13, 2006).

The EPA has long maintained that the CSAPR trading programs can function as a BART alternative for the relevant covered visibility pollutants for the EGU BART sources that are covered by the relevant CSAPR trading program. The EPA promulgated CSAPR, a revised multistate trading program to replace CAIR, in 2011 (and revised it in 2012).[76] CSAPR established FIP requirements for several states, including Texas, to address the states' interstate transport obligation under CAA section 110(a)(2)(D)(i)(I). The EPA made the original CSAPR better-than-BART determination in a 2012 rulemaking, codified at 40 CFR 51.308(e)(4), and subsequently reaffirmed that determination in a 2017 rulemaking.[77] At the time of the 2012 rulemaking, Texas was part of the CSAPR annual NO_x and SO_2 trading programs to address interstate transport of $PM_{2.5}$. Therefore, Texas was among the states who could choose to meet BART obligations for their EGUs through participation in the relevant CSAPR trading program. The EPA subsequently withdrew Texas from CSAPR for purposes of addressing interstate transport requirements for the $PM_{2.5}$ NAAQS (i.e., Texas was withdrawn from the annual NO_x and SO_2 trading programs) in response to the D.C. Circuit Court's decision in *EME Homer City Generation, L.P. v. EPA*.[78] However, when the EPA promulgated the Texas SO_2 Trading Program, the Agency reasoned that it could nonetheless satisfy the Regional Haze Rule's BART alternative requirements by demonstrating that SO_2 emissions under the Texas SO_2 Trading Program were comparable to SO_2 emissions anticipated from Texas had Texas remained in CSAPR.[79]

[76] Federal Implementation Plans; Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals, 76 FR 48208 (Aug. 8, 2011).
[77] 77 FR 33642 (June 7, 2012) (codified at 40 CFR 51.308(e)(4)). The final rule amended the Regional Haze Rule to allow states whose EGUs participate in one of the CSAPR trading programs for a given pollutant to rely on that participation as an alternative to source-specific BART requirements); *see also* 82 FR 45481 (Sep 29, 2017) (affirming that CSAPR remained better than BART nationwide after Texas and other states were removed from CSAPR for PM).
[78] *EME Homer City Generation, L.P. v. EPA,* 795 F. 3d 118, 138 (D.C. Cir. 2015).
[79] 82 FR 48324, 48336 (Oct. 17, 2017).

As we explained in our June 2020 affirmation of the Texas SO_2 Trading Program, annual SO_2 emissions for sources covered by the Texas SO_2 Trading Program are constrained by the annual budgets and an assurance level of 255,083 tons. The EPA then added to this amount an estimated 35,000 tons per year of emissions from units not covered by the Texas SO_2 Trading Program, but which would have been covered by the CSAPR program. This yielded 290,083 tons of SO_2, which was below the 317,100-tons per year emissions level assumed for Texas sources under CSAPR.[80] Thus, rather than considering the Texas SO_2 Trading Program in isolation as a BART alternative and comparing the effects of that program to the effects of source-specific BART for the relevant EGUs in Texas to determine whether it made "greater reasonable progress," the EPA instead relied on the CSAPR Better-than-BART analysis as the basis for concluding that the Texas SO_2 Trading Program provided greater reasonable progress than BART – even though the Texas SO_2 Trading Program was not connected in any way to CSAPR and functioned as its own, independent BART alternative.

Such reliance is inconsistent with the requirements of the Regional Haze Rule's requirements for a BART alternative in 40 C.F.R. § 51.308(e)(2), which requires a comparison between the BART alternative and the BART benchmark for the relevant sources.[81] Because the Texas SO_2 Trading Program is an intrastate program, the effects of that program should have been considered independently of CSAPR. Indeed, participation in the CSAPR program in lieu of implementing BART requirements is provided for under a separate provision of the Regional Haze Rule, 40 C.F.R. § 51.308(e)(4). Thus, the EPA could only rely on the analytical demonstrations made in the CSAPR better-than-BART rulemakings had Texas remained in

[80] Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan 85 FR 49170, 49183 (Aug. 12, 2020).
[81] 40 CFR 51.308(e)(2).

CSAPR.[82] Once Texas was withdrawn from CSAPR, the EPA could not rely on that provision as justification that the Texas SO_2 Trading Program made “greater reasonable progress” than BART at Texas EGUs. Thus, whether the Texas SO_2 Trading Program provided similar or more reductions than anticipated had Texas remained in CSAPR is irrelevant and fails to demonstrate that it achieves greater reasonable progress than BART as required by 40 C.F.R. § 51.308(e)(2).

Furthermore, although the Texas SO_2 Trading Program was modeled after CSAPR in its design and operation, the two programs are distinct. First, the sources covered under the Texas SO_2 Trading Program do not include all the sources in Texas that were part of the CSAPR trading program.[83] Thus, the EPA had to rely on an unenforceable emissions assumption of 35,000 tons per year from the non-covered sources to allow for an apples-to-apples comparison between the Texas program and the CSAPR program in terms of the universe of sources analyzed.[84] However, there was no obligation that the non-covered sources would emit below that assumed level in perpetuity.

Second, CSAPR was designed as a regional trading program that involved the participation of sources from many states over a wide geographic area, as compared to the Texas SO_2 Trading Program, which is an intrastate trading program. As such, the Texas SO_2 Trading Program is limited to sources in Texas which cannot trade allowances with sources in other states as is permitted under CSAPR. Because of the scope of participation in CSAPR, in demonstrating that CSAPR was Better-than-BART, the EPA was not required by the rule to demonstrate that CSAPR achieves greater reasonable progress than BART at every Class I area

[82] Even after the removal of Texas (and other states) from CSAPR following the remand of certain CSAPR budgets in *EME Homer City Generation*, Texas (and other states) had the option to voluntarily participate in CSAPR to gain the benefit of addressing BART obligations. Texas declined to adopt this approach.
[83] *See* 85 FR 49170, 49184.
[84] 85 FR 49170, 49184.

or in every state.[85] Rather, the EPA demonstrated that CSAPR achieved greater visibility improvement than BART when visibility was averaged across all Class I areas.[86] In averaging visibility improvement from CSAPR across all the affected Class I areas, the 2012 demonstration properly relied on the substantial emission reductions anticipated to occur in the eastern half of the country for which other states, which included Texas at the time, could take advantage of without having to apply source-specific BART.[87] For example, SO_2 emissions in Tennessee were anticipated to be approximately 321,300 in a nationwide BART scenario,[88] but only approximately 66,700 under CSAPR.[89] Similar situations were also anticipated in several other states including Ohio (546,700 tons of SO_2 under a nationwide BART scenario compared to only 190,000 tons under CSAPR); Indiana (454,500 tons of SO_2 under a nationwide BART scenario compared to only 202,900 tons under CSAPR); and Pennsylvania (222,600 tons of SO_2 under a BART scenario compared to only 134,500 tons under CSAPR).[90]

---

[85] *See* 77 FR at 33650.

[86] *See e.g.,* 77 FR at 33650.

[87] Specifically, in the 2017 affirmation that CSAPR remains better than BART after withdrawal of multiple states from CSAPR, including Texas, we stated that the 2012 analytic demonstration showed that the difference in emissions between the CSAPR scenario plus BART elsewhere would lead to an overall reduction in SO2 emission reductions for the overall modeled region of 773,000 tons as compared to application of source specific BART nationwide. See memo entitled ''Sensitivity Analysis Accounting for Increases in Texas and Georgia Transport Rule State Emissions Budgets,'' Docket document ID No. EPA–HQ–OAR–2011–0729–0323 (May 29, 2012) (2012 CSAPR/BART sensitivity analysis memo), at 1–2, available in the docket for this proposed action.

[88] For all BART-eligible EGUs in the Nationwide BART scenario and for BART-eligible EGUs not subject to CSAPR for a particular pollutant in the CSAPR + BART-elsewhere scenario, the modeled emission rates were the presumptive EGU BART limits for SO_2 and NO_X as specified in the BART Guidelines (Appendix Y to 40 CFR part 51—Guidelines for BART Determinations under the Regional Haze Rule), unless an actual emission rate at a given unit with existing controls was lower, in which case the lower emission rate was modeled. (For additional details see Technical Support Document for Demonstration of the Transport Rule as a BART Alternative, Docket document ID No. EPA-HQ-OAR-2011-0729-0014 (December 2011) (2011 CSAPR/BART Technical Support Document EPA-HQ-OAR-2011-0729-0014) in www.regulations.gov.

[89] *See* Technical Support Document for Demonstration of the Transport Rule as a BART Alternative, Docket document ID No. EPA–HQ–OAR–2011–0729–0014 (December 2011) (2011 CSAPR/BART Technical Support Document EPA-HQ-OAR-2011-0729-0014), at table 2–4, also available in the docket for this action at document ID EPA-R06-OAR-2016-0611-0196.

[90] *See* Technical Support Document for Demonstration of the Transport Rule as a BART Alternative, Docket ID No. EPA–HQ–OAR–2011–0729–0014 (December 2011) (2011 CSAPR/BART Technical Support Document), at table 2–4, available in www.regulations.gov, document ID EPA-R06-OAR-2016-0611-0196.

However, while CSAPR leads to greater emissions reductions overall over the modeled region, we explained that for certain CSAPR states, application of source-specific BART was projected to lead to greater emission reductions than through participation in CSAPR. We explained that this could occur in CSAPR states that have numerous BART-eligible EGUs.[91] One such state where this was anticipated to occur was Texas. In the case of Texas, the projected SO_2 emissions from affected EGUs in the modeled nationwide-BART scenario (139,300 tons per year) are considerably lower than the projected SO_2 emissions from the affected EGUs in the CSAPR scenario (266,600 tons per year as modeled, and up to approximately 317,100 tons, as addressed in the 2012 CSAPR/BART sensitivity analysis memo).[92] Thus, the application of presumptive source-specific BART, instead of participation in the CSAPR SO_2 trading program, would have resulted in projected emissions of 139,300 tons per year, a reduction in projected SO_2 emissions by between approximately 127,300 tons and 177,800 tons from the CSAPR SO_2 trading program emissions.[93] As a result, a demonstration that the Texas SO_2 Trading Program achieves equivalent emissions reductions as anticipated had Texas remained in CSAPR fails to demonstrate that the Texas SO_2 Trading Program achieves greater reasonable progress than BART for the BART sources in Texas participating in the Texas

[91] 81 FR 78954, 78962-63 (Nov. 10, 2016).
[92] 81 FR 78954, 78962-63 (Nov. 10, 2016).
[93] 81 FR 78954, 78962-63 (Nov. 10, 2016). As stated in both the proposal and final rule withdrawing Texas from CSAPR SO_2 trading program, the 127,300-ton amount was described as the minimum reduction in projected Texas SO_2 emissions because it did not reflect a 50,500-ton increase in the Texas SO_2 budget that occurred after the original CSAPR scenario was modeled. If that budget increase had been reflected in the original CSAPR scenario, modeled Texas EGU SO_2 emissions in that scenario would likely have been higher, potentially by the full 50,500-ton amount. The CSAPR budget increase would have had no effect on Texas EGUs' modeled SO_2 emissions under BART. Therefore, the 127,300-ton minimum estimate of the reduction in projected Texas SO_2 emissions caused by removing Texas EGUs from CSAPR for SO_2, which are computed as the difference between Texas EGUs' collective emissions in the original CSAPR scenario and the BART scenario, may be understated by as much as 50,500 tons. *See* 82 FR at 45492; 81 FR at 78962-63.

SO_2 Trading Program. The comparison in estimated emissions above strongly indicates this not to be the case.

Thus, we propose that it was an error to allow the Texas SO_2 Trading Program to rely on a demonstration made for a different and unconnected BART alternative (i.e., CSAPR) because it failed to comport with the requirements in 40 CFR 51.308(e)(2). Instead, the EPA should have assessed whether the Texas SO_2 Trading Program provides for greater reasonable progress than BART for those BART sources in Texas covered by the Texas SO_2 Trading Program.[94]

3. The Texas SO_2 Trading Program Does Not Achieve Greater Reasonable Progress Than BART

Because the 2017 Texas BART FIP and subsequent affirmation improperly relied on CSAPR to support the validity of the Texas SO_2 Trading Program, there is no evidence in the record to support a finding that the Texas SO_2 Trading Program provides for greater reasonable progress than BART when compared to the proper BART benchmark (i.e., source specific BART for the sources in Texas covered by the Texas SO_2 Trading Program). Rather, the relevant information indicates that had the Texas SO_2 Trading Program been compared to the appropriate Texas-specific BART benchmark, the analysis would have found that the Texas SO_2 Trading Program does not provide for greater reasonable progress than BART at the Class I areas affected by those sources.

For purposes of determining whether it is appropriate to now withdraw the Texas SO_2 Trading Program as a BART alternative, we have conducted an analysis comparing the effects of the Texas SO_2 Trading Program to source-specific BART for the relevant EGU BART sources.

[94] *See* 40 C.F.R. 51.308(e)(2), (e)(3).

The purpose of this analysis is not to conduct a full re-evaluation of the Texas SO_2 Trading Program under each of the requirements of the BART-alternative regulations of 40 CFR 51.308(e)(2). Rather, this analysis evaluates the question of whether, even under conservative assumptions, the Texas SO_2 Trading Program, when compared to the proper BART benchmark (source-specific BART for the relevant sources in Texas), could possibly achieve greater reasonable progress. The analysis confirms a stark disparity in outcomes, with the Texas SO_2 Trading Program not securing any additional emission reductions and even allowing for substantial SO_2 emissions *increases* from baseline levels while source-specific BART would achieve substantial SO_2 emissions decreases. We propose to find that the installation and operation of source-specific BART controls substantially outperform the Texas SO_2 Trading Program in terms of emission reductions and resulting visibility improvement at the Class I areas that are affected by the sources in Texas, and that the Texas SO_2 Trading Program does not achieves greater reasonable progress than BART as required by 40 C.F.R. § 51.308(e)(2).

As we explained earlier in Section II and in our June 2020 affirmation of the Texas SO_2 Trading Program as an alternative to BART for SO_2, annual SO_2 emissions for sources covered by the Texas SO_2 Trading Program are constrained by the annual budgets and an assurance level of 255,083 tons.[95] The Texas SO_2 Trading Program imposes a penalty surrender ratio of three allowances for each ton of emissions in any year in excess of the assurance level, which provides a disincentive against emissions exceeding the assurance level. Added to this amount is an estimated 35,000 tons per year of emissions from units not covered by the Texas SO_2 Trading Program, but which would have been covered by the CSAPR program. This yields an estimated 290,083 tons of SO_2 from all Texas EGUs. This is significantly higher than the 139,300 tons per

[95] 85 FR 49170, 49183 (Aug. 12, 2020).

year estimated in the nationwide BART only scenario for Texas EGUs in the 2012 CSAPR better than BART demonstration. In other words, the presumptive BART scenario developed for the 2012 demonstration would result in approximately 150,000 tons per year less SO_2 emissions than the Texas SO_2 Trading Program scenario.

We note, however, that this comparison of emissions of the Texas SO_2 Trading Program and presumptive BART from the 2012 CSAPR analysis does not account for recent facility shutdowns. Sandow[96], Big Brown,[97] and Monticello[98] retired in 2018. Welsh Unit 2 retired in 2016,[99] and the J. T. Deely units retired at the end of 2018.[100] While these retirements have resulted in overall emission reductions, they have also resulted in a surplus of allowances that serve to decrease or eliminate any regulatory pressure from the Texas SO_2 Trading Program to further decrease emissions from current levels. Under the Texas SO_2 Trading Program, retired units continue to be allocated allowances for a period of five years.[101] After that period, those allowances are still allocated but to the supplemental allowance pool.[102] Sources participating in the Texas SO_2 Trading Program have flexibility to transfer allowances among multiple participating units under the same owner/operator when planning operations, and unused

[96] *See* letter dated February 14, 2018, from Kim Mireles of Luminant to the TCEQ requesting to cancel certain air permits and registrations for Sandow Steam Electric Station available in the docket for this action at document ID EPA-R06-OAR-2016-0611-0143 for Sandow Unit 4 and document ID EPA-R06-OAR-2016-0611-0134 for Sandow Unit 5.
[97] *See* letter dated March 27, 2018, from Kim Mireles of Luminant to the TCEQ requesting to cancel certain air permits and registrations for Big Brown available in the docket for this action at document ID EPA-R06-OAR-2016-0611-0130.
[98] *See* letter dated February 8, 2018, from Kim Mireles of Luminant to the TCEQ requesting to cancel certain air permits and registrations for Monticello available in the docket for this action at document ID EPA-R06-OAR-2016-0611-0132.
[99] Welsh Unit 2 was retired on April 16, 2016, pursuant to a Consent Decree (No. 4:10-cv-04017-RGK) and subsequently removed from the Title V permit (permit no. O26). *See* "TX197.183 Turk (Welsh) Consent Decree 12.22.11" (document ID EPA-R06-OAR-2016-0611-0138) and "TX187.129 AIR OP_O26-13404_Permits_Public_20160919_Project File Folder_1410429 (document ID EPA-R06-OAR-2016-0611-0129) in the docket for this action.
[100] *See* letters dated December 2021 from the TCEQ to Danielle Frerich regarding the cancellation of air quality permits for the J. T. Deely Units available in the docket for this action.
[101] 40 CFR 97.911(a)(2).
[102] 40 CFR 97.911(a)(2).

allowances can be banked for use in future years.[103] Furthermore, allowances are allocated from the supplemental allowance pool each year if the reported emissions for an ownership group exceeds the amount of allowances allocated to that group, with a limit on these allocations in any year of 16,688 tons plus any allowances added to the pool in that year from retired units. The combination of allocations to retired units, banking of allowances, and allocations from the supplemental allowance pool results in an excess availability in allowances to cover the sources' emissions with the only limitation being the assurance level.

Because the Texas SO_2 Trading Program contains both BART and non-BART EGUs, we must establish emission estimates for both types of units to compare the installation and operation of source-specific BART for SO_2 to the Texas SO_2 Trading Program. For the purposes of comparing the Texas SO_2 Trading Program to source-specific BART, we assume that all BART-eligible coal-fired sources are subject to BART[104] and that source-specific BART results in emission reductions greater than or equal to those reductions estimated based on a presumptive BART level of 0.15 lb/MMBtu.[105,106] For the gas fired sources included in the Texas SO_2 Trading Program, we assume that they are not subject to BART for purposes of this analysis and thus treat them as non-BART sources.[107] We note that an assumption of 95 percent control

[103] *See* 45 FR at 49208.
[104] This is consistent with our subject to BART screening analysis below in Section VII.
[105] BART Guidelines, 70 FR 39104, 39131 (July 6, 2005). "…, we are establishing a BART presumptive emission limit for coal-fired EGUs greater than 200 MW in size without existing SO_2 control. These EGUs should achieve either 95 percent SO_2 removal, or an emission rate of 0.15 lb SO_2/MMBtu, unless a State determines that an alternative control level is justified based on a careful consideration of the statutory factors."
[106] In Section VII of this proposed action, we evaluate and identify which of the BART-eligible EGUs currently in the Texas SO_2 Trading Program are subject to BART sources as well as the analysis of the five factors that inform the BART determination for subject to BART sources. In Section VIII, we provide our weighing of the factors and proposed determination on source-specific BART requirements for these sources.
[107] We note that in Section VII we determined that W. A. Parish Unit WAP4, which is gas fired, is subject to BART because it is co-located with two other coal-fired BART units (Units WAP5 & WAP6). Thus, in evaluating whether the BART-eligible units at W. A. Parish were subject to BART we evaluated emissions from Units WAP4 with WAP5 & WAP6, which is consistent with the subject to BART evaluation process as explained in Section VII. For Unit WAP4, we are not assuming any further reductions due to application of BART because of the inherently low levels of SO_2 from firing natural gas.

would result in lower emissions than the 0.15 lb/MMBtu rate for all BART units, however, for the purpose of this comparison, we are selecting a conservative (high) estimate for presumptive BART limits to illustrate the large emission reductions available through the installation and operation of BART even at this conservatively high emission rate. We also note that the assumption of 0.15 lb/MMBtu is more conservative than what was used for these units in the 2012 CSAPR Better-than-BART analysis.

To estimate emissions for BART sources, we multiplied the average heat input from 2016-2020 by a presumptive BART emission rate of 0.15 lb/MMBtu.[108] To obtain a conservative estimate for non-BART units, we used the maximum annual emissions from the 2016-2020 period for each unit. The use of the maximum annual emissions from the 2016-2020 period for each non-BART unit provides a conservative assumption of emissions anticipated from these units to represent a scenario in which they are not participating in the Texas SO_2 Trading Program. We then added the estimated emissions from the BART units together with the estimated emissions from the non-BART units to compare emissions between the Texas SO_2 Trading Program and BART. Sources that have recently shutdown were not included in the analysis. In addition to comparing emission levels under source-specific BART to the assurance level of the Texas SO_2 Trading Program, we also consider the impact of source-specific BART on current emissions levels under the program.

Table 1 shows 2021 annual emissions in one column, and the other column shows estimated emissions under the presumptive BART assumptions plus the maximum annual emissions from the 2016-2020 period for those non-BART units as described in the paragraph above. The 2021 emissions are the most recent annual emissions available at the time of this

[108] The Fayette BART units (Units 1 and 2) are currently operating well below 0.15 lb/MMBtu. For these units, the maximum annual emissions from 2016-2020 were used in this comparison.

action and represent emissions under the Texas SO_2 Trading Program regulations, including the amended provisions in the 2020 final action. Under these conservative assumptions, presumptive BART for those BART-eligible units plus the maximum annual emissions from the 2016-2020 period for those non-BART units still results in an approximately 32 percent reduction in total estimated emissions as compared to actual emissions for these same sources as provided for under the Texas SO_2 Trading Program. This is a significant reduction compared to actual emissions and far below the assurance level of 255,083 tons per year. Additionally, in looking at only subject-to-BART units, presumptive BART reduces emissions by more than 70,000 tons as compared to what those units are emitting under the Texas SO_2 Trading Program. The estimated emissions for the BART sources under presumptive BART of 24,108 tons is also far below the allowance allocations to these units of 96,487 tons of allowances per year. As detailed in Section VIII, our determinations of source-specific BART result in even larger emission reductions than what was calculated here under these presumptive BART assumptions.

Table 1. Comparison of Actual Emissions under the Texas SO_2 Trading Program and Presumptive BART[109]

	2021 Actual Emissions (tons)	**Presumptive BART emissions plus max. emissions for non-BART (tons)**
Total (SO_2 Trading Program Units)	129,790	88,023
Total (Subject-to-BART units only)	96,601	24,108

[109] *See* "Annual EI Texas thru 2021.xlsx" available in the docket for this action.

Because the alternative program under review, the Texas SO_2 Trading Program, results in much higher emissions than source-specific BART, we are proposing to find that the Texas SO_2 Trading Program does not meet the requirements of a BART alternative under 40 CFR 51.308(e)(2). As discussed earlier, if the distribution of emissions under the alternative program is not substantially different than under BART, and the alternative program results in greater emissions reductions of each relevant pollutant than under BART, then the alternative program may be deemed to achieve greater reasonable progress.[110] The Texas SO_2 Trading Program under review does not result in greater emission reductions than under BART. Rather, compared to the presumptive BART scenario, emissions from sources covered by the Texas SO_2 Trading Program are similar or higher. Furthermore, the Texas SO_2 Trading Program does not secure emission reductions at non-BART sources in Texas to compensate for the higher than BART emissions at the Texas BART sources. In these situations, a BART alternative program can only achieve greater reasonable progress than BART when emission reductions from non-BART sources are large enough (or the resulting visibility benefits from those reductions are large enough) to compensate for smaller emission reductions at BART sources than would be achieved under source-specific BART.

This finding that the Texas SO_2 Trading Program, which was designed to achieve a stringency level on par with CSAPR, does not achieve greater reasonable progress than BART, when isolated to the units in Texas, is not surprising, and it does not undermine the continued validity of CSAPR as a BART-alternative in other states. As discussed earlier in Section IV.B.2, the CSAPR program resulted in large emission reductions anticipated to occur in the eastern half of the country due to its coverage of both many BART sources and many non-BART sources.

[110] 40 CFR 51.308(e)(2)(E), (e)(3).

However, this was not true for every state. Texas, for instance, generally had higher emissions under the CSAPR BART alternative compared to source-specific BART, since it had relatively more BART-eligible sources compared to many other states in the eastern United States. As discussed, Texas was removed from the CSAPR SO_2 trading program in September 2017, and therefore, cannot rely on the reductions in the eastern half of the country brought about by CSAPR because the Texas SO_2 Trading Program is independent of CSAPR. As an independent BART alternative, the Texas SO_2 Trading Program is deficient because it secures no additional emission reductions from any non-BART sources and, as demonstrated, the BART emission reductions that would need to be offset are very large. Because the Texas SO_2 Trading Program secures no reductions (and in fact would have permitted significant growth in emissions from current levels), the establishment of source-specific BART emission limits would result in large additional emission reductions by comparison that would result in comparatively greater visibility benefits. Accordingly, the Texas SO_2 Trading Program does not provide for greater reasonable progress than the installation and operation of BART, and therefore, fails to meet the requirements for a BART alternative under the Regional Haze Rule. Thus, we are proposing to withdraw the Texas SO_2 Trading Program and instead propose to satisfy the Regional Haze Rule's SO_2 BART requirements through conducting a source-specific BART analysis for certain BART-eligible EGU sources identified in Sections VII and VIII of this action.

V. CSAPR Participation as a BART Alternative

A. Introduction

If the proposed source-specific BART requirements in Texas are finalized, the analytical basis within the EPA's withdrawal of Texas from the CSAPR trading programs for annual NOx and SO_2 in September of 2017 will be restored (82 FR 45481). Therefore, the EPA is proposing to find that, if this proposal to implement source-specific BART requirements at certain EGUs in Texas is finalized, the analytical basis for concluding that the implementation of CSAPR in the remaining covered states will continue to meet the criteria for a BART alternative for those states remains valid. Related to this finding, the EPA is also proposing to deny a 2020 administrative petition for partial reconsideration brought by Sierra Club, National Parks Conservation Association (NPCA), and Earthjustice of the EPA's June 2020 denial of a 2017 petition to reconsider the EPA's original September 2017 finding, the details of which are provided in the next sections. Based on this analysis, the EPA is affirming the current Regional Haze Rule provision allowing states whose EGUs continue to participate in a CSAPR trading program for a given pollutant to continue to rely on CSAPR participation as a BART alternative for its BART-eligible EGUs for that pollutant. The public is invited to comment on this proposed basis for denying the 2020 petition for partial reconsideration.

B. Background

1. CSAPR Better-Than-BART

a. General Background

CSAPR (76 FR 48208; Aug. 8, 2011) implements a series of emissions trading programs for sulfur dioxide (SO_2) and nitrogen oxides (NO_X) across the eastern United States to address interstate ozone and fine particulate ($PM_{2.5}$) pollution under CAA section 110(a)(2)(D)(i)(I) (the "good neighbor provision").[111] The EPA has issued regulations allowing the CSAPR states to rely on participation in these trading programs in lieu of requiring source-specific BART controls at their BART-eligible EGUs covered by one or more of the CSAPR trading programs

[111] 42 U.S.C. 7410(a)(2)(D)(i)(I).

with respect to the visibility pollutant at issue (i.e., NO_X or SO_2). *See* 40 CFR 51.308(e)(4).[112] This determination authorizing reliance on CSAPR participation as a BART alternative is often referred to as "CSAPR Better-Than-BART."[113]

In the EPA's 2012 action promulgating CSAPR Better-Than-BART, the EPA used air quality modeling to show CSAPR met the two-pronged numerical test for a BART alternative.[114] To account for certain CSAPR state-budget increases that were made after the initial modeling was conducted, the 2012 CSAPR Better-Than-BART determination also included a sensitivity analysis (2012 sensitivity analysis) that examined the effect of those budget increases on the modeled visibility impacts for the CSAPR scenario.[115] In the 2012 action, the EPA found that under a scenario analyzing the visibility benefits of CSAPR (referred to as the "CSAPR + BART-Elsewhere" scenario), visibility would not decline in any Class I area compared to a baseline scenario, satisfying the first prong of the two-pronged BART-alternative test. The EPA also found that the CSAPR + BART-Elsewhere scenario would result in an overall improvement in visibility on average across affected Class I areas, as compared to a scenario analyzing visibility benefits resulting from "presumptive" BART limits at all BART-eligible sources (referred to as the "nationwide BART" scenario), satisfying the second prong of the two-pronged BART-alternative test. The EPA's findings held true whether looking at the 60 Class I areas in the eastern U.S. most heavily impacted by the sources subject to CSAPR or looking at all 140 Class I areas in the continental United States. The United States Court of Appeals for the D.C.

[112] The EPA had previously made a similar finding for the predecessor to CSAPR, the Clean Air Interstate Rule (CAIR), and this determination was upheld in *UARG v. EPA*, 471 F.3d 1333 (D.C. Cir. 2006) (*UARG I*).
[113] 77 FR 33642 (June 7, 2012).
[114] 40 CFR 51.308(e)(3); *See generally* 77 FR 33642 (June 7, 2012).
[115] *See* 77 FR 33642, 33651-52; This sensitivity analysis was included in a technical memo accompanying the 2012 action. *See* "Sensitivity Analysis Accounting for Increases in Texas and Georgia Transport Rule State Budgets," Docket ID No. EPA-HQ-OAR-2011-0729 and in the docket for this action at document ID EPA-R06-OAR-2016-0611-0113.

Circuit (D.C. Circuit) upheld this action in *UARG v. EPA*, 885 F.3d 714 (D.C. Cir. 2018) (*UARG II*).

To account for certain CSAPR state-budget increases that were made after the initial modeling was conducted, the 2012 CSAPR Better-Than-BART determination also included a sensitivity analysis (2012 sensitivity analysis) that examined the effect of those budget increases on the modeled visibility impacts for the CSAPR + BART-Elsewhere scenario.[116] The EPA determined that the increases in SO_2 and NO_X budgets were small enough that they did not require a comprehensive set of new power sector and air quality modeling. Instead, the 2012 sensitivity analysis applied a simple, but very conservative adjustment factor to the existing quantitative air quality modeling results to show that, even with the higher emissions budgets, the CSAPR + BART-Elsewhere scenario was still projected to show greater reasonable progress toward natural visibility than the Nationwide BART scenario. Specifically, the 2012 sensitivity analysis applied adjustments to visibility impacts in the CSAPR + BART-Elsewhere scenario to account for increases in the SO_2 budgets for Texas and Georgia, since SO_2-driven impacts were the most important impacts in the analysis and Texas and Georgia had the largest SO_2 budget increases.

The 2012 sensitivity analysis identified sets of Class I areas that are most impacted by emissions in Texas (9 areas) and Georgia (7 areas) and assumed that *all* of the modeled visibility improvement in those sets of Class I areas is due to SO_2 emissions reductions from either Texas or Georgia, respectively. This methodology is highly conservative because the projected SO_2 emissions reductions in Texas and Georgia represented only 4.4 percent and 1.8 percent,

[116] *See* 77 FR 33642, 33651-52; This sensitivity analysis was included in a technical memo accompanying the 2012 action. *See* "Sensitivity Analysis Accounting for Increases in Texas and Georgia Transport Rule State Budgets," Docket ID No. EPA-HQ-OAR-2011-0729 and in the docket for this action at document ID EPA-R06-OAR-2016-0611-0113.

respectively, of the total projected regional emissions reductions in the CSAPR + BART-Elsewhere scenario, and the Class I areas most impacted by Texas and Georgia emissions are also affected by the very large emissions reductions projected from other states in the regional CSAPR + BART-Elsewhere scenario. By assuming a linear relationship between emissions increases in Texas and Georgia and visibility degradation in those Class I areas, the EPA very conservatively determined that even with the budget increases, the CSAPR + BART-Elsewhere scenario was projected to achieve greater visibility improvement than the Nationwide BART scenario on average across all 60 eastern Class I areas and all 140 nationwide Class I areas, thereby satisfying the second prong of the two-pronged test under 40 CFR 51.308(e)(3). The sensitivity analysis also showed no visibility degradation in the CSAPR + BART-Elsewhere scenario relative to the baseline scenario at any Class I area, thereby satisfying the first prong of the test.

b. The CSAPR Remand and the EPA's 2017 Affirmation of CSAPR Better-Than-BART

The original 2011 CSAPR action was largely upheld by the Supreme Court in 2014.[117] However, the case was remanded to the D.C. Circuit to assess whether the EPA may have "over-controlled" certain states for purposes of implementing the good neighbor provision. In *EME Homer City Generation, L.P. v. EPA*, 795 F.3d 118 (D.C. Cir. 2015), based on this potential for overcontrol, the court remanded certain state budgets to the EPA, including Texas' SO_2 budget, which the EPA had established to address $PM_{2.5}$ transport.

To address the remand, in November 2016, the EPA proposed to remove Texas EGUs from the CSAPR SO_2 Group 2 Trading Program as well as the CSAPR NO_X Annual Trading

[117] *EPA v. EME Homer City Generation, L.P.*, 572 U.S. 489 (2014).

Program, which similarly addressed $PM_{2.5}$ transport.[118] The EPA indicated that if the withdrawal was finalized, Texas would no longer be eligible under 40 CFR 51.308(e)(4) to rely on participation of its EGUs in a CSAPR trading program as an alternative to source-specific SO_2 BART determinations.[119] The EPA also provided a proposed analysis (2016 proposed analysis) showing that the changes in the geographic scope of CSAPR coverage since the EPA's original 2012 CSAPR Better-Than-BART determination, including the proposed withdrawal of Texas EGUs from the CSAPR SO_2 and annual NO_X trading programs, would not have altered the 2012 determination because the changes would not have altered the EPA's analytical findings that both prongs of the two-pronged test for a BART alternative under 40 CFR 51.308(e)(3) were satisfied.[120]

In September 2017, the EPA finalized the withdrawal of Texas EGUs from the CSAPR SO_2 and annual NO_X programs.[121] In the same action, the EPA also issued its final analysis (2017 final analysis) showing that, even with Texas EGUs no longer participating in these programs (and other changes in the geographic coverage of CSAPR), the EPA's original 2012 analytical finding that CSAPR is better than BART remained valid.[122] In response to comments received on the 2016 proposed analysis, the EPA's 2017 final analysis included an evaluation of the potential impact of emissions shifting under both prongs of the two-pronged test for a BART alternative under 40 CFR 51.308(e)(3). This analysis focused on the fact that if Texas sources were withdrawn from the CSAPR SO_2 Group 2 Trading Program, they would no longer purchase

[118] *See* 81 FR 78954 (Nov. 10, 2016).
[119] *Id.* at 78956; the EPA also noted that because Texas EGUs would continue to participate in a CSAPR trading program for ozone-season NO_X emissions, Texas would still be eligible under 40 CFR 51.308(e)(4) to rely on CSAPR participation as an alternative to source-specific NO_X BART determinations for the covered sources. 81 FR at 78962.
[120] *See id.* at 78961-64.
[121] *See* 82 FR 45481 (September 29, 2017).
[122] *See id.* at 45490-94.

up to 22,300 SO_2 allowances from sources in other Group 2 states, as had been projected in the CSAPR + BART-Elsewhere scenario used in the 2012 CSAPR Better-Than-BART determination. As to the first prong, the EPA explained that, relative to a baseline scenario without CSAPR or BART, a revised CSAPR + BART-Elsewhere scenario with an increased quantity of SO_2 allowances available for use by units in other Group 2 states would still show no visibility degradation at any Class I area because, absent unusual circumstances that the EPA showed were not expected to occur in this case, all units in the remaining Group 2 states would still have stronger incentives to control their SO_2 emissions in the revised CSAPR + BART-Elsewhere scenario (with some positive allowance price) than in the baseline scenario (without any allowance price).[123]

As to the second prong, the EPA assumed that the availability of 22,300 additional allowances would result in a 22,300-ton increase in emissions in the remaining Group 2 states, but observed that the potential adverse visibility impacts of those emissions would be more than offset by the favorable visibility impacts of at least 127,300 tons of reduced emissions in Texas under presumptive source-specific SO_2 BART for the state's BART-eligible EGUs.[124] In other words, under the methodological framework the EPA devised in 2012 to compare CSAPR with BART, *see* 77 FR 33648-49, the EPA concluded that the "Transport Rule [CSAPR] + BART Elsewhere" scenario would still outperform the "Nationwide BART" scenario, even if Texas's EGU BART sources fell under the "BART Elsewhere" category rather than the CSAPR category. Thus, the EPA's conclusion that CSAPR satisfied the second prong of the two-pronged test rested in part on assuming net SO_2 reductions of approximately 105,000 tons from

[123] *Id.* at 45493.
[124] *Id.* at 45493-94.

presumptive source-specific BART in Texas, after accounting for the potential for shifting of 22,300 tons of emissions from Texas to the remaining Group 2 states.[125]

2. Promulgation and Affirmation of the Texas SO_2 Trading Program as a BART Alternative

As explained in Section II.C, rather than finalize source-specific BART SO_2 emission limits for subject-to-BART EGUs in Texas (as had been assumed in the September 2017 finding affirming CSAPR as better than BART), the EPA took final action in October 2017 establishing an intrastate trading program for SO_2 for certain Texas EGUs as an alternative to BART.[126] On June 29, 2020, after completing rulemaking proceedings on reconsideration, the EPA affirmed the Texas SO_2 Trading program as a BART alternative, with certain amendments as proposed in November 2019.[127] This rulemaking, its rationale, and subsequent reconsideration and affirmation in June 2020 are summarized in Section II.C and are not repeated here.

3. The EPA's Denial of Petition for Reconsideration of the 2017 Affirmation of CSAPR As a BART Alternative

On November 28, 2017, the Sierra Club and NPCA submitted a petition for partial reconsideration (2017 petition) under CAA section 307(d)(7)(B) of our September 29, 2017 action withdrawing Texas from the CSAPR trading programs for SO_2 and annual NO_X and affirming that CSAPR participation continues to satisfy requirements as a BART alternative (September 2017 Final Rule).[128] The petitioners alleged that it was impracticable, and indeed

---

[125] 82 FR 45493-94.
[126] *See* 82 FR 48324 (October 17, 2017); In the same January 2017 and October 2017 notices, the EPA also proposed and finalized action to rely on CSAPR participation as a NO_X BART alternative for Texas EGUs, *see* 82 FR at 946; 82 FR at 48361.
[127] 85 FR 49170 (Aug. 12, 2020).
[128] The Sierra Club and National Parks Conservation Association, Petition for Partial Reconsideration of Interstate Transport of Fine Particulate Matter: Revision of Federal Implementation Plan Requirements for Texas; Final Rule; 82 FR 45,481 (September 29, 2017); EPA-HQ-OAR-2016-0598; FRL-9968-46-OAR (November 28, 2017).

impossible, to comment on the relationship between the Texas SO_2 Trading Program and the CSAPR Better-Than-BART analysis in the final rule because the EPA did not finalize the Texas SO_2 Trading Program until after the final rule was signed and the EPA had assumed presumptive source-specific SO_2 BART controls in the rulemaking record for the final rule.[129] The petitioners also alleged it was impracticable to comment on other aspects of the EPA's geographic emissions shifting analysis, which was not presented until the final rule.[130] The petitioners argued that both sets of issues are of central relevance to the September 2017 Final Rule.

With respect to the BART requirements in Texas, the petitioners argued that the final rule was "impermissibly based upon a factual predicate that no longer exists – namely, that sulfur dioxide emission reductions associated with the installation of presumptive source-specific BART would be install [sic] at Texas EGUs."[131] The petitioners went on to purportedly demonstrate, using the 2012 sensitivity analysis methodology developed by the EPA, that source-specific BART in Texas would improve visibility in Class I areas in or affected by Texas more than CSAPR or the Texas SO_2 Trading Program.[132]

Concurrently with the affirmation of the Texas SO_2 Trading Program on June 29, 2020, the EPA issued a denial of the 2017 petition (2020 Denial).[133] In addition to addressing the other objections raised in the 2017 petition,[134] the EPA included an updated sensitivity analysis (2020

[129] *Id.* at 8-9.
[130] *Id.* at 9.
[131] *Id.* at 10.
[132] *Id.* at 11-13.
[133] 85 FR 40286 (July 6, 2020) ("2020 Denial"); *See, e.g.,* Letter from U.S. EPA Administrator Andrew Wheeler to Joshua Smith, Sierra Club, denying petition for reconsideration (June 29, 2020), Docket ID EPA-HQ-OAR-2016-0598-0036. The EPA concurrently sent identical letters to other petitioners. This letter, rather than the *Federal Register* notice, is what we refer to when citing specific pages in the "2020 Denial."
[134] In their 2020 petition for partial reconsideration summarized below, Petitioners did not renew their objections as to other aspects of the EPA's analysis in the 2020 Denial and therefore these issues will not be summarized here. As to the issues not raised in their 2020 petition, but addressed in denying their 2017 petition, the EPA is not reopening the bases for denial of these objections set forth in its 2020 Denial letter. We note that in their 2020 petition for partial reconsideration, Petitioners noted that they "continue to object" to the EPA's use of "presumptive" BART

sensitivity analysis) assessing whether CSAPR would remain a valid BART alternative based on assumptions regarding emissions performance under the Texas SO_2 Trading Program rather than source-specific BART.[135] The EPA used the same methodology it had used in its 2012 CSAPR Better-Than-BART determination and applied an emissions assumption for the Texas SO_2 Trading Program used by Petitioners in their 2017 petition of 320,600 tons of SO_2 per year. The EPA also used an assumption that there would be a 22,300-ton increase in emissions in a single state in the Group 2 trading program, Georgia.[136] The EPA presented the results of this analysis in Table 3 of the 2020 Denial, and we asserted that for purposes of the "prong 2" portion of the BART analysis, that CSAPR continued to perform equal to or better than BART.[137] Based on this analysis, the EPA reaffirmed the 2012 CSAPR Better-Than-BART determination, albeit now on the assumption of the Texas SO_2 Trading Program operating in Texas rather than CSAPR or presumptive source-specific BART.[138]

C. Summary of the 2020 Petition for Reconsideration and Associated Litigation

On August 28, 2020, the Sierra Club, NPCA, and Earthjustice submitted a petition for partial reconsideration under CAA section 307(d)(7)(B) of the EPA's 2020 Denial of their

---

limits in its CSAPR better than BART analysis. See 2020 Petition at 5 n.10. The EPA is not revisiting this issue here. The EPA explained in its 2020 Denial why this objection did not meet either prong of the CAA section 307(d)(7)(B) test for mandatory reconsideration, including that petitioners could have, but did not, comment on this issue in the original 2017 affirmation rulemaking proceeding. See 2020 Denial at 19-20.

[135] 2020 Denial at 13-16.

[136] *Id.* at 14-15.

[137] *Id.* at 16.

[138] Note that neither in the 2020 Denial or in this present proposal are we reopening our determination in the September 2017 Final Rule that withdrawal of Texas from the annual NO_X trading program would have caused sufficient changes in modeled NO_X emissions in a revised CSAPR scenario to materially alter the visibility impacts comparison. *See* 82 FR 45492 n.82. As detailed in the November 2016 proposal, projected annual NO_X emissions from Texas EGUs were only 2,600 tons higher than the annual NO_X emissions projected for the CSAPR + BART-Elsewhere case, in which it was assumed that the EGUs were subject to CSAPR requirements for both ozone-season and annual NO_X emissions. The EPA determined that this relatively small increase in NO_X emissions in the CSAPR + BART-Elsewhere case would have been too small to cause any change in the results of either prong of the two-pronged CSAPR-Better-Than-BART test.

November 2017 petition for reconsideration (2020 petition).[139] The petitioners alleged that because the EPA presented the updated CSAPR Better-than-BART sensitivity calculations for the first time in its 2020 Denial of the 2017 Petition (and thus they were not afforded an opportunity to comment), and because that updated analysis is of central relevance to the September 2017 Final Rule, the EPA must reconsider both actions under CAA section 307(d)(7)(B). The petitioners alleged that, contrary to the EPA's conclusions in its 2020 Denial, the updated CSAPR Better-Than-BART analysis demonstrates that visibility improvement under CSAPR is *not* equal to or greater than visibility improvement under source-specific BART averaged over all 140 Class I areas, or the 60 eastern Class I areas covered by CSAPR.[140]

Specifically, Petitioners note that had the EPA's results been reformatted to display two decimal places instead of one, the average visibility improvement for the CSAPR + BART-Elsewhere scenario would have been less than that of the Nationwide BART scenario on two of the four metrics used.[141] Thus, Petitioners concluded that the EPA's 2020 sensitivity analysis proves that the visibility improvement in the CSAPR + BART-Elsewhere scenario, with the adjustments made to Texas's and Georgia's emissions, is not equal to or greater than the visibility improvement in the Nationwide BART scenario. Moreover, Petitioners also argue that it was impracticable for them to raise these issues concerning the sensitivity analysis during the comment period for the September 2017 Final Rule because the sensitivity calculations were presented for the first time in the 2020 Denial.[142] The Petitioners claim that the data within the 2020 sensitivity analysis addresses an issue of central relevance to the September 2017 Final

[139] Petition for Partial Reconsideration of Denial of Petition for Reconsideration and Petition for Reconsideration of the Interstate Transport of Fine Particulate Matter: Revision of Federal Implementation Plan Requirements for Texas (Aug. 28, 2020), Docket ID EPA-HQ-OAR-2016-0598-0041.
[140] *Id.* at 9.
[141] *Id.* at 11.
[142] *Id.* at 12.

Rule, i.e., whether CSAPR results in an overall improvement in visibility compared to source-specific BART. Moreover, because Petitioners claim that the EPA's sensitivity analysis showed that source-specific BART would result in greater visibility improvement than CSAPR, they argue that the EPA's continued reliance on CSAPR as a BART alternative is arbitrary, capricious, and contrary to law.[143]

Sierra Club, NPCA, and Earthjustice also filed a petition for judicial review of the 2020 Denial in the U.S. Court of Appeals for the District of Columbia.[144] On November 3, 2020, this challenge and the Petitioners' preexisting challenge to the September 2017 final analysis (No. 17-1253 (D.C. Cir.)) were consolidated. On January 13, 2021, the court placed the petitions for review in abeyance pending further order of the court, and the court directed the parties to file motions to govern following the EPA's action on the 2020 petition.

The EPA is now proposing to deny the 2020 petition in this action.

D. Criteria for Granting a Mandatory Petition for Reconsideration

Under section 307(d)(7)(B) of the Act, "[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment . . . may be raised during judicial review."[145] However, "[i]f a person raising an objection can demonstrate . . . that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment . . . and if such objection is of central relevance to the outcome of the rule, the Administrator shall convene a proceeding for reconsideration of the

[143] *Id.* at 13.
[144] *National Parks Conservation Association et al. v. EPA,* No. 20-1341 (D.C. Cir. filed Sept. 4, 2020).
[145] 42 U.S.C. 7607(d)(7)(B).

rule."[146] The EPA considers an objection to be of "central relevance" to the outcome of a rule "if it provides substantial support for the argument that the regulation should be revised."[147]

E. The EPA's Evaluation of the Petition for Reconsideration

The EPA proposes to deny the 2020 petition because the objections raised to the 2020 Denial are not "centrally relevant" under a scenario in which the EPA finalizes the proposal to withdraw the present BART-alternative intrastate trading FIP for Texas EGUs and replaces those requirements with source-specific SO_2 BART requirements. Under this scenario, the findings made in the September 2017 Final Rule (i.e., the EPA's finding that CSAPR remains better than BART) can be affirmed. The Agency acknowledges that the petitioners raised legitimate questions in the 2020 petition concerning the 2020 sensitivity analysis and the conclusion that CSAPR remains better than BART in a scenario in which the Texas SO_2 Trading Program is implemented. However, with this proposal and the return to source-specific BART requirements in Texas, this issue is effectively resolved. The 2020 petition can therefore be denied since the objection raised is no longer centrally relevant.

For purposes of the 2012 analytic demonstration that CSAPR provides for greater reasonable progress than BART, the EPA treated Texas EGUs as subject to CSAPR for SO_2 and annual NO_X (as well as ozone-season NO_X). In the September 2017 Final Rule, the EPA recognized that the treatment of Texas EGUs in the 2012 analysis would have been different if those sources were not in the CSAPR SO_2 and annual NO_X programs. To address potential concerns about continuing to rely on CSAPR participation as a BART alternative for EGUs in the remaining CSAPR states, the EPA provided an analysis explicitly addressing the potential

[146] *Id.*
[147] *See Coal. For Responsible Regulation, Inc. v. EPA*, 684 F.3d 102, 125 (D.C. Cir. 2012) (internal citation and quotation omitted).

effect on the 2012 analytic demonstration if the treatment of Texas (and several other states') EGUs had been consistent with the updated scope of CSAPR coverage following the D.C. Circuit's remand of CSAPR in *EME Homer City*. In particular, in its September 2017 Final Rule, the EPA assumed that, as for all other non-CSAPR states, Texas EGUs would be subject to presumptive, source-specific SO_2 BART limits.

As discussed below, if the EPA's proposal in this action to implement source-specific BART requirements at certain EGUs in Texas is finalized, the analytical basis for the EPA's September 2017 conclusions will be restored, and that analysis will continue to support the conclusion that CSAPR participation would achieve greater reasonable progress than BART, despite the change in the treatment of Texas EGUs. Consequently, by virtue of this proposed action that relates to Texas, the EPA is also able to propose to reaffirm the continued validity of the CSAPR better-than-BART provision, 40 CFR 51.308(e)(4), which authorizes the use of CSAPR participation as a BART alternative for BART-eligible EGUs for a given pollutant in states whose EGUs continue to participate in a CSAPR trading program for that pollutant. In the September 2017 Final Rule, the EPA evaluated whether a revised CSAPR scenario reflecting the removal of Texas EGUs from the CSAPR SO_2 program (and other changes in CSAPR's geographic scope) would continue to satisfy the two-pronged test under 40 CFR 51.308(e)(3). Regarding the changes in CSAPR requirements for Texas EGUs, the EPA determined that the changes would have no adverse impact on the 2012 analytic demonstration. Finalization of this proposal would restore the analytical bases for the EPA's conclusions in the September 2017 Final Rule. We discuss that analysis in the following paragraphs and explain how it would be restored if this action is finalized as proposed.

As the EPA concluded in the September 2017 Final Rule, Texas EGUs are ineligible to rely on CSAPR as an SO_2 BART alternative. In this proposal, we are affirming this position and rejecting the contrary arguments that the Agency previously put forward in support of the Texas BART-alternative FIP, as explained above in Section IV. As explained in the November 2016 proposal,[148] if this information had been available at the time of the 2012 CSAPR Better-than-BART demonstration, the treatment of Texas EGUs in the baseline case and in the Nationwide BART case would not have changed, but in the CSAPR + BART-Elsewhere case, Texas EGUs would have been treated as subject to source-specific SO_2 BART instead of being treated as subject to CSAPR SO_2 requirements. In the case of Texas, the projected SO_2 emissions from affected EGUs in the modeled Nationwide BART scenario (139,300 tons per year) are considerably lower than the projected SO_2 emissions from the affected EGUs in the CSAPR + BART-Elsewhere scenario (266,600 tons per year as modeled, and up to approximately 317,100 tons, as addressed in the 2012 sensitivity analysis).

As modeled, treating Texas EGUs in the CSAPR + BART-Elsewhere scenario as subject to source-specific SO_2 BART instead of CSAPR SO_2 requirements would therefore have reduced projected SO_2 emissions by between 127,300 tons and approximately 177,800 tons in this scenario, thereby improving projected air quality in this scenario relative to projected air quality in both the Nationwide BART scenario and the baseline scenario.[149] At the lower end of this range, a reduction in SO_2 emissions of 127,300 tons would represent a reduction of over four percent of the total SO_2 emissions from EGUs in all modeled states in the CSAPR + BART-elsewhere scenario. The EPA has previously observed that the visibility improvements from

[148] *See* 81 FR 78954 (Nov. 10, 2016).
[149] As explained in greater detail in Section IV, while many states participating in CSAPR were projected to have substantially lower SO_2 emissions under CSAPR as compared to implementing BART requirements, this was not the case for Texas's EGUs.

CSAPR relative to BART are primarily attributable to the greater reductions in SO_2 emissions from CSAPR across the overall modeled region in the CSAPR + BART-Elsewhere scenario relative to the Nationwide BART scenario.

With a return to source-specific SO_2 BART requirements at the relevant Texas EGUs, this analysis will continue to (or, once again will) be valid. Further, we propose to find that the conclusions reached in the September 2017 Final Rule regarding "emissions shifting" from Texas back into the remaining CSAPR region would remain valid if source-specific BART requirements are implemented at the relevant Texas EGUs. The September 2017 Final Rule responded to a comment regarding potential "emissions shifting" when Texas was removed from the CSAPR SO_2 trading program. For purposes of the second prong, to account for the effect of potential emissions shifting caused by the fact that Texas sources would no longer purchase SO_2 allowances from sources in other CSAPR Group 2 states, the EPA assumed that SO_2 emissions in Georgia could increase by up to 22,300 tons, the quantity of allowances that Texas had been projected to purchase from the other Group 2 states in the original CSAPR scenario. However, as detailed above, the EPA showed in 2017 that a potential shift of up to 22,300 SO_2 tons to Georgia (or other CSAPR states) would be dwarfed by the lower SO_2 tons emitted in Texas under a source-specific BART scenario (127,300 tons or more). Therefore, the EPA proposes that the September 2017 Final Rule's conclusion that CSAPR would continue to pass both prongs of the better-than-BART test, even accounting for emissions shifting, remains valid (or will once again be valid) if this proposal is finalized and source-specific BART is implemented in Texas.

In summary, the EPA proposes to affirm that if the information regarding the proposed withdrawal of CSAPR FIP requirements for SO_2 for Texas EGUs had been available at the time of the 2012 CSAPR Better-than-BART analytic demonstration, the CSAPR + BART-Elsewhere scenario would have reflected SO_2 emissions from Texas EGUs under presumptive source-specific BART. This would have been 127,300 or more tons per year lower than the emissions projections under CSAPR and remains a valid assumption so long as the presumed source-specific SO_2 BART reductions are in fact required in Texas. Under this assumption—which is, again, made possible by withdrawing the current BART-alternative FIP and implementing source-specific BART in Texas as outlined in this proposal—emissions would not have changed in the Nationwide BART or baseline scenarios. Instead, modeled visibility improvement in the CSAPR + BART-Elsewhere scenario would have been even larger relative to the other scenarios than what was modeled in the 2012 analytic demonstration.

Lower SO_2 emissions in Texas (after implementation of source-specific BART) would clearly lead to more visibility improvement on the best and worst visibility days in the nearby Class I areas. Since the "original" CSAPR + BART-Elsewhere scenario passed both prongs of the better-than-BART test (compared to the Nationwide BART scenario and the baseline scenario), a modified CSAPR + BART-Elsewhere scenario without Texas in the CSAPR region would without question also have passed both prongs of the better-than-BART test. The EPA therefore further proposes that there is no need to do any new modeling or more complicated sensitivity analysis to affirm the findings of the September 2017 Final Rule. And for the same reason, there is no need to do any additional modeling or analysis to support this finding under the current Texas BART proposal in this action (i.e., to withdraw the Texas SO_2 Trading Program and replace the FIP with source-specific BART for Texas EGUs), assuming this proposal is finalized.

Therefore, the EPA proposes to deny the 2020 petition for partial reconsideration and proposes to again affirm the use of CSAPR as a BART alternative for all states whose EGUs continue to participate in the CSAPR trading programs as to the relevant pollutants. Specifically, the EPA proposes to conclude that, if the present proposal and the restoration of the analytical premise for the findings of the September 2017 Final Rule are finalized, the objections that the 2020 petition for partial reconsideration raised as to the analysis the EPA presented in the 2020 Denial will be resolved and are therefore not of "central relevance" to the September 2017 Final Rule. We are providing the opportunity for, and invite, public comment on this proposed denial of the petition for partial reconsideration.

VI. The EPA's Authority to Promulgate a FIP Addressing SO_2 and PM BART

A. CAA Authority to Promulgate a FIP For SO_2 BART

Under section 110(c) of the CAA, whenever the EPA disapproves a mandatory SIP submission in whole or in part, the EPA is required to promulgate a FIP within 2 years unless we approve a SIP revision correcting the deficiencies before promulgating a FIP. 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, the EPA has had the authority and obligation to promulgate a FIP to address BART for Texas EGUs for SO_2. As discussed in Section II, we exercised this FIP authority in October 2017 to promulgate a BART alternative (the Texas SO_2 Trading Program) to address the inadequacy of Texas's SIP as it pertained to BART requirements for Texas EGUs for SO_2. Because we are now proposing that the basis for the Texas SO_2 Trading Program as a BART alternative rested on an erroneous interpretation of our BART alternative regulations, and thus proposing to withdraw the program for the reasons explained throughout Section IV, we have an obligation under the CAA to promulgate a FIP in its place. We propose to exercise this FIP authority through conducting a source-specific BART analysis for those BART-eligible EGU sources participating in the Texas SO_2 Trading Program and, as appropriate, establish source-specific BART emission limits and associated compliance requirements, as identified in Sections VII and VIII of this action.

B. Error Correction and CAA Authority to Promulgate a FIP – PM BART

The EPA proposes that its prior approval of a portion of Texas's 2009 Regional Haze SIP related to its finding that no EGUs were subject to BART requirements for PM (PM BART) was in error under CAA section 110(k)(6). Section 110(k)(6) of the CAA provides the EPA with the authority to make corrections to actions that are subsequently found to be in error. *Ass'n of Irritated Residents v. EPA*, 790 F.3d 934, 948 (9th Cir. 2015) (explaining that 110(k)(6) is a "broad provision" enacted to provide the EPA with an avenue to correct errors). The EPA proposes that its approval of the portion of Texas's Regional Haze SIP addressing PM BART for EGUs was in error, as the approval was based on the Texas SO_2 Trading Program that was promulgated in error. Under CAA section 110(k)(6), once the EPA determines that its previous action approving a SIP revision was in error, the EPA may revise such action as appropriate without requiring any further submission from the State. To correct the error here, the EPA proposes to revise its previous approval of the portion of Texas's 2009 Regional Haze SIP addressing PM BART for EGUs and proposes to instead disapprove this portion of Texas's SIP.

In the 2009 Texas Regional Haze SIP, Texas conducted a screening analysis of the visibility impacts from PM emissions in isolation and determined that no EGUs were subject to BART for PM based on an assumption that BART requirements for EGUs for both SO_2 and NO_X were covered by participation in an earlier trading program (CAIR). This decision was consistent with a 2006 EPA memorandum titled “Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations”; however, that memorandum stated that pollutant-specific screening is only appropriate in the limited situation where a state is relying on a BART alternative, such as a trading program, to address both NO_X and SO_2 BART.[150]

In our 2017 Texas BART FIP, we created the Texas SO_2 Trading Program as a BART alternative to satisfy SO_2 BART requirements for EGUs. As a result, the Texas BART FIP created a scenario in which Texas EGUs were again subject to trading programs to address both NO_X and SO_2 BART, and therefore, the EPA approved the pollutant-specific screening for PM as performed by Texas in its 2009 Regional Haze SIP submittal. Upon further consideration, and as described in more detail above in Section IV, we have determined that the Texas SO_2 Trading Program as promulgated in 2017, and affirmed in 2020, was based on an erroneous interpretation of our BART alternative regulations. As such, it failed to meet the requirements for a valid BART alternative and thus we are proposing to withdraw the Texas SO_2 Trading Program and to satisfy SO_2 BART requirements through conducting a source-specific BART analysis. The basis for approval of Texas’s SIP related to the BART requirements for PM for EGUs rested on our creation of a BART alternative for SO_2, and we are proposing in this action to determine that the Texas SO_2 Trading Program is not a valid BART alternative. Consistent with our proposal regarding the Texas SO_2 Trading Program, we are also proposing that our approval of the portion of the 2009 Texas Regional Haze SIP related to PM BART requirements for EGUs was in error.

Accordingly, the EPA is proposing to correct its previous approval of the Texas 2009 Regional Haze SIP submittal related to PM BART for EGUs by proposing to disapprove Texas’s pollutant-specific PM screening analysis and determination that PM BART emission limits are

[150] Memorandum from Joseph Paisie to Kay Prince, “Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations,” July 19, 2006, available in the docket for this action.

not required for any Texas EGUs. The EPA is proposing this action through an error correction under CAA section 110(k)(6). If the EPA finalizes this disapproval, the EPA will have the authority and obligation under CAA section 110(c)(1)(B), to promulgate a FIP within 2 years. As part of this rulemaking, the EPA proposes to promulgate a FIP addressing PM BART requirements and satisfying that FIP obligation. As discussed further in Section VII and Section VIII, the EPA is proposing source-specific PM BART requirements for those EGUs that we propose to find subject to BART.

VII. BART Analysis for SO_2 and PM

As discussed in Section IV of this action, we are proposing to withdraw the Texas SO_2 Trading Program previously established as an alternative to SO_2 BART for Texas EGUs. Thus, to satisfy SO_2 BART requirements for Texas, we are proposing to conduct a source-specific BART evaluation consistent with the BART Guidelines for appropriate EGU sources. Specifically, we must evaluate EGUs that were previously identified as BART-eligible, but for which no subject-to-BART determinations were made because they were included in the Texas SO_2 Trading Program. Additionally, because our approval of the portion of the Texas Regional Haze SIP related to PM BART for EGUs was in error, we are now proposing an error correction to disapprove that portion of the Texas SIP. We propose to address the deficiency through a source-specific BART evaluation consistent with the BART Guidelines for PM BART for the EGU sources that were previously identified as BART-eligible, but for which no subject-to-BART determinations were made because they were included in the Texas SO_2 Trading Program.

A. Identification of Sources Subject to BART

In January 2016, we approved Texas's determination of which non-EGU sources in the state are BART-eligible and the determination that none of the state's BART-eligible non-EGU sources are subject to BART because they are not reasonably anticipated to cause or contribute to visibility impairment at any Class I areas.[151] In our October 2017 Texas BART FIP,[152] and subsequent affirmation in 2020, addressing BART requirements for Texas EGUs, we noted that all BART-eligible EGUs in Texas are either covered by a BART alternative or have screened out of being subject to BART. Our October 2017 FIP lists the units covered by the BART alternative for SO_2 (i.e., the Texas SO_2 Trading Program) and identifies which of those units are BART-eligible.[153] For those BART-eligible EGUs that were not covered by the Texas SO_2 Trading Program, we finalized determinations that those EGUs are not subject-to-BART for NO_X, SO_2, and PM based on screening methods as described in our 2017 proposed rule and BART Screening TSD.[154]

Because we are now proposing to withdraw the Texas SO_2 Trading Program, we must evaluate the EGU sources that were previously identified as BART-eligible, but for which no subject-to-BART determinations were made because they were included in the Texas SO_2 Trading Program. The sources included in the Texas SO_2 Trading Program are identified in Table 2.

Table 2. Sources Included in the Texas SO_2 Trading Program

Owner/Operator	Units	BART-Eligible
AEP	Welsh Power Plant Unit 1	Yes
	Welsh Power Plant Unit 2	Yes

[151] *See* 81 FR 296, 301 (Jan. 5, 2016).
[152] *See* 82 FR at 48328 (Oct. 17, 2017).
[153] 82 FR at 48329 (Oct.17, 2017).
[154] *See* 82 FR at 48328-29 (Oct.17, 2017). Table 2 in the October 2017 notice lists the EGUs that we finalized as being BART-eligible, but for which we determined were not be subject-to-BART based on various screening analysis as more fully described in the 2017 proposal (82 FR at 918-21). We are not reopening that determination in this action.

	Welsh Power Plant Unit 3	No
	H W Pirkey Power Plant Unit 1	No
	Wilkes Unit 1†	Yes
	Wilkes Unit 2†	Yes
	Wilkes Unit 3†	Yes
CPS Energy	J. T. Deely Unit 1	Yes
	J. T. Deely Unit 2	Yes
	O. W. Sommers Unit 1†	Yes
	O. W. Sommers Unit 2†	Yes
LCRA	Fayette / Sam Seymour Unit 1	Yes
	Fayette / Sam Seymour Unit 2	Yes
Luminant	Big Brown Unit 1	Yes
	Big Brown Unit 2	Yes
	Martin Lake Unit 1	Yes
	Martin Lake Unit 2	Yes
	Martin Lake Unit 3	Yes
	Monticello Unit 1	Yes
	Monticello Unit 2	Yes
	Monticello Unit 3	Yes
	Sandow Unit 4	No
	Stryker ST2†	Yes
	Graham Unit 2†	Yes
	Coleto Creek Unit 1	Yes
NRG	Limestone Unit 1	No
	Limestone Unit 2	No
	W. A. Parish Unit WAP4†	Yes
	W. A. Parish Unit WAP5	Yes
	W. A. Parish Unit WAP6	Yes
	W. A. Parish Unit WAP7	No
Xcel	Tolk Station Unit 171B	No
	Tolk Station Unit 172B	No
	Harrington Unit 061B	Yes
	Harrington Unit 062B	Yes
	Harrington Unit 063B	No
El Paso Electric	Newman Unit 2†	Yes
	Newman Unit 3†	Yes
	Newman Unit **4†	Yes
	Newman Unit **5†	Yes

† Gas-fired or gas/fuel oil-fired units

Some of the BART-eligible sources that were included in the Texas SO_2 Trading Program have retired. Welsh Unit 2 retired in 2016[155] and Big Brown,[156] Monticello,[157] and the J.T. Deely units retired at the end of 2018.[158] These shutdowns are permanent and enforceable because the CAA permits for these units have been cancelled or the units have been withdrawn from the facilities' Title V operating permits. These units may not return to operation without going through CAA new source permitting and Title V operating permitting requirements. Therefore, because the units are permanently retired, it is not necessary to include these units in our screening analysis to determine whether these sources are subject to BART.

To determine which of those remaining BART-eligible sources listed in Table 2 are anticipated to cause or contribute to visibility impairment in any Class I area (subject-to-BART)[159], 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. The BART source is the collection of BART-eligible emission units at a facility. A detailed discussion of the subject-to-BART screening analysis is provided in the 2023 BART Modeling TSD.[160] We summarize the methodology and results of this analysis here.

1. Modeling Approach

---

[155] Welsh Unit 2 was retired on April 16, 2016, pursuant to a Consent Decree (No. 4:10-cv-04017-RGK) and subsequently removed from the Title V permit (permit no. O26). We have included the Consent Decree, permitting notes, and new Title V permit showing that the Unit is removed in the docket for this action.

[156] *See* letter dated March 27, 2018, from Kim Mireles of Luminant to the TCEQ requesting to cancel certain air permits and registrations for Big Brown available in the docket (EPA-R06-OAR-2016-0611-0132) for this action.

[157] *See* letter dated February 8, 2018, from Kim Mireles of Luminant to the TCEQ requesting to cancel certain air permits and registrations for Monticello available in the docket (EPA-R06-OAR-2016-0611-0130) for this action.

[158] *See* letter dated December 15, 2021, from Johnny Bowers, Team Leader Air Permits Division at TCEQ to Danielle Frerich regarding the cancellation of air quality permits for the J.T. Deely units available in the docket for this action.

[159] *See* 40 C.F.R. Part 51, Appendix Y, III, How to Identify Sources "Subject to BART."

[160] *See* our 2023 BART Modeling TSD in our docket.

For states (or the EPA in the case of a FIP) using modeling to determine the applicability of BART to single sources, the first step in the BART Guidelines is to set a contribution threshold to assess whether the impact of a single source (collectively the BART-eligible units at a specific facility) 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 (dv) change or more from an individual source to 'cause' visibility impairment, and a change of 0.5 dv to 'contribute' to impairment."[161] The BART Guidelines further advise 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 describe 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.[162] 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 lower contribution threshold. Therefore, our analysis employs a contribution threshold of 0.5 dv.

In this action we conducted modeling using both CALPUFF[163] and CAMx.[164] In the 2005 BART Guidelines, CALPUFF was in part chosen because it is much less resource intensive with respect to required computing power, run time, and development of model inputs than chemical transport models such as CAMx. Additionally, CAMx tools for assessing single source

---

[161] 70 FR at 39118.
[162] 70 FR at 39118.
[163] EPA used the version of CALPUFF approved previously for regulatory modeling (CALPUFF version 5.8.5, level 15214) as discussed on EPA's website (https://www.epa.gov/scram/air-quality-dispersion-modeling-alternative-models) and this CALPUFF version is available for download from Exponent at https://www.src.com/.
[164] CAMx is available for download at https://www.camx.com/.

impacts were still undergoing development at that time. CAMx tools have advanced since 2005, and while still resource intensive, for this action we were able to conduct CAMx modeling using TCEQ's modeling platform as a starting point for this assessment. We discuss details of the CALPUFF and CAMx modeling systems throughout this section and in the 2023 BART Modeling TSD.

As recommended in the BART Guidelines, we performed stand-alone, source-specific CALPUFF modeling on several of the remaining BART-eligible sources included in Table 2 to determine which of the BART-eligible sources in Table 2 cause or contribute to visibility impairment in nearby Class I areas. CALPUFF is a multi-species non-steady-state puff dispersion model that simulates the effects of pollution transport, dispersion, transformation, and removal of emissions from modeled sources for transport distances beyond 50 km using general background concentrations to represent air pollution levels that the modeled sources emissions interact. Relevant guidance[165] states that the CALPUFF model is generally applicable at distances from 50 km to at least 300 km downwind of a source. However, previous Regional Haze BART SIP modeling conducted by consultants and the States extended beyond 300km for numerous BART analyses.[166] In fact, in evaluating the Texas 2009 Regional Haze SIP, the EPA,

---

165 Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long-Range Transport and Impacts on Regional Visibility, EPA- 454/R-98-019, IWAQM, 1998; "Federal Land Managers' Air Quality Related Values Workgroup (FLAG)": Phase I Report, FLAG, USDI – National Park Service, Air Resources Division, Denver, CO., 2000. https://www.nature.nps.gov/air/Pubs/pdf/flag/FlagFinal.pdf; Revisions to the Guideline on Air Quality Models: Adoption of a Preferred Long Range Transport Model and Other Resources, 72 FR 18440 (Apr. 15, 2003).

166 Historically, the EPA has indicated that use of CALPUFF was generally acceptable at 300 km and for larger emissions sources with elevated stacks, such as coal-fired power plants, we and FLM representatives have also allowed or supported the use of CALPUFF results at larger distances, beyond 400 km in some cases. For example, South Dakota used CALPUFF for Big Stone's BART determination, including its impact on multiple Class I areas further than 400 km away. See 76 FR 76646, 76654 (Dec. 8, 2011), 77 FR 24845 (Apr.26, 2012). Nebraska relied on CALPUFF modeling to evaluate whether numerous power plants were subject to BART where the "Class I areas [were] located at distances of 300 to 600 kilometers or more from" the sources. *See* Best Available Retrofit Technology Dispersion Modeling Protocol for Selected Nebraska Utilities, p. 3, EPA Docket ID No. EPA-R07-OAR-2012-0158-0008.

FLM representatives, and TCEQ agreed with using CALPUFF for Texas sources for distances out to 614 km.[167] Initially, CALPUFF results beyond 300 km were thought to be potentially conservative (overestimate impacts); however subsequent analysis of CALPUFF indicates that it can also underpredict impacts at ranges greater than 300km.[168] For this particular BART analysis, we chose to evaluate CALPUFF results out to approximately 450 km due to these potential uncertainties that seem to be larger at ranges greater than 450 km.[169] All BART-eligible sources that we modeled with CALPUFF in this action have at least one Class I area within the more typical CALPUFF range of 300km (see Table 3 for distance to most impacted Class I areas for each modeled source). This use of CALPUFF is consistent with the EPA's recommendation in the 2005 BART Guidelines[170] to determine whether a source is subject to BART and in conducting the BART analysis for those sources determined to be subject to BART.[171] We also have CAMx modeling results for all coal-fired BART-eligible sources and as such we have both CALPUFF and CAMx modeling results for the coal-fired sources within 450 km of Class I area(s). For those sources beyond 450 km, we only used CAMx modeling results as discussed in more detail later in this section.

---

[167] In our 2014 proposed action and the 2016 final action on the 2009 Texas Regional Haze SIP, we approved the use of CALPUFF to screen BART-eligible non-EGU sources at distances of 400 to 614 km for some sources. 79 FR 74818 (Dec. 16, 2014), 81 FR 296 (Jan. 5, 2016).

[168] "Documentation of the Evaluation of CALPUFF and Other Long Range Transport Models using Tracer Field Experiment Data" (PDF)(247 pp, 8 MB, 05-01-2012, 454-R-12-003). Prepared for the U.S. Environmental Protection Agency by the ENVIRON International Corporation. (EPA Contract No: EP-D-07-102, Work Assignment No: 4-06); "Evaluation of Chemical Dispersion Models using Atmospheric Plume Measurements from Field Experiments" (PDF)(127 pp, 3 MB, 09-01-2012). Prepared for the U.S. Environmental Protection Agency by the ENVIRON International Corporation. (EPA Contract No: EP-D-07-102, Work Assignment No: 4-06 and 5-08); and "Comparison of Single-Source Air Quality Assessment Techniques for Ozone, PM2.5, other Criteria Pollutants and AQRVs" (PDF)(143 pp, 19 MB, 09-01-2012). Prepared for the U.S. Environmental Protection Agency by the ENVIRON International Corporation. (EPA Contract No: EP-D-07-102, Work Assignment No: 4-06 and 5-08); https://www.epa.gov/scram/air-modeling-reports-and-journal-articles. See 2023 BART Modeling TSD for further discussion on this topic.

[169] We discuss the choice of using CALPUFF model results in the 300-450 km range in more detail in the 2023 BART Modeling TSD.

[170] *See* 70 FR 39104, 39122–23 (July 6, 2005).

[171] 70 FR at 39122.

Consistent with the BART Guidelines, for those sources modeled with CALPUFF, we compared the 98th percentile (equivalent to the 8th highest daily value in each year modeled) impact from the three modeled years to the 0.5 dv screening threshold following the modeling protocol described in the 2023 BART Modeling TSD.[172] The BART Guidelines recommend that states (or the EPA in the case of a FIP) 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. Consistent with this recommendation, in this action, we used the 24-hour average actual emission rate from the highest emitting day during the baseline period.

For this proposed action, we conducted modeling using a baseline period of emissions data of 2016 - 2020 and used meteorological data for 2016 - 2018 to evaluate source visibility impacts to Class I areas. Our selection of this baseline period for subject-to-BART screening modeling was made based on consideration of a number of factors. We note that most BART screening analyses, including the BART screening in the 2009 Texas Regional Haze SIP, were based on a 2000-2004 baseline period, used 2001-2003 meteorological data, and used 2002 in the baseline modeling to project 2018 visibility conditions for the first planning period SIPs. Our 2017 proposed rule also used this period.[173]

We selected the 2016-2020 emissions baseline period for subject-to-BART screening in this instance because recent actual emissions more accurately reflect future anticipated emissions which is required in evaluating controls. In addition, this emissions baseline period is consistent

[172] In the 2005 BART Guidelines the selection of the 98th percentile value rather than the maximum value was made to address concerns with CALPUFF's limitations that could result in the maximum from CALPUFF modeling being overly conservative. We state that, "Most important, the simplified chemistry in the model tends to magnify the actual visibility effects of that source. Because of these features and the uncertainties associated with the model, we believe it is appropriate to use the 98th percentile—a more robust approach that does not give undue weight to the extreme tail of the distribution." 70 FR at 39121.
[173] See generally 82 FR 912 (January 4, 2017).

with the 2016-2018 meteorological period modeled. In this manner, the screening, visibility benefit analysis, cost analysis, and consideration of existing controls are all based on consideration of the same baseline meteorological time period, operating conditions, and emissions. The 2000-2004 baseline period is no longer representative of anticipated future emissions or current operations because more recent regulatory actions, such as the MATS rule, and market pressures have impacted how these units now operate. We also note that our previous use of baseline emissions data from 2000-2004 reflected steady-state operating conditions during periods of high-capacity utilization and was appropriate for the screening nature of the analysis rather than any specific federally enforceable limit in effect at that time. We believe this same approach, updated for 2016-2020, continues to serve the same function and provides a suitable estimate of emissions during high utilization for each of these sources. Additionally, it also allows the screening, visibility benefit analysis, cost analysis, and consideration of existing controls to all be based on the same baseline period for meteorological data, operating conditions, and emissions. Using an appropriate, updated baseline is also the foundation for evaluating control costs once a source is determined to be subject to BART. The BART determination includes consideration of past practices, existing controls, and anticipated future operation. The BART Guidelines state that in evaluating the costs of controls as part of the five-factor analysis for sources determined to be subject to BART, baseline annual emissions utilized for control cost analyses should be a realistic depiction of anticipated annual emissions for the source and calculated based upon continuation of past practice[174] in the absence of enforceable limitations.

[174] Past practices can include a broad consideration of operations, changes in market conditions, and unique situations that can impact emissions.

For both the CALPUFF and CAMx modeling, the maximum 24-hour emission rate (lb/hr) for NO_X and SO_2 from the 2016-2020 baseline period for each source was identified through a review of the daily emission data obtained from the EPA's Clean Air Markets Program Data[175] for each of the BART-eligible units included in Table 2. Because daily emissions are not available for PM, we used data from EPA's Air Markets Program Data and TCEQ's Central Registry EI information to obtain PM_{10} and $PM_{2.5}$ tpy emission rates for each year (2016-2020) on a unit basis. We used the annual average lb/MMBtu and the maximum daily heat input to calculate the maximum daily PM_{10} and $PM_{2.5}$ emissions rates that were used in the subject to BART modeling and were also used in the control cases. For the gas and gas/fuel oil facilities,[176] we utilized the heat input data from the EPA Clean Air Markets Division (CAMD) coupled with the EPA's AP-42 emission factors to estimate maximum PM_{10} and $PM_{2.5}$ emissions. The 2023 BART Modeling TSD includes additional discussion and source-specific information used in the CALPUFF modeling for this portion of the screening analysis.

As previously discussed, while the BART Guidelines recommend the use of CALPUFF to determine which sources are anticipated to contribute to visibility impairment, the Guidelines also allow the use of another "appropriate model" to predict the visibility impacts from a single source at a Class I area. Because some of these BART-eligible sources (included in Table 2) are beyond the distance to Class I areas for which CALPUFF modeling is typically used, we used photochemical grid modeling (CAMx) to evaluate the visibility impacts of those sources. In addition, we also used CAMx to evaluate the other BART-eligible coal-fired EGUs with SO_2 emissions located within the typical CALPUFF modeling range. The CAMx modeling includes all of these emission sources to provide a consistent approach to compare the modeling results

[175] https://campd.epa.gov/. *See* "2016-2020 CAMD Data Evaluation.xlsx" in the docket for this action.

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

across all these sources. CAMx is a photochemical grid model that is formulated to assess the long-range transport of emissions from sources up to distances of several thousand miles including emissions from sources outside the range that CALPUFF is typically utilized. CAMx allows modeling of impacts from individual sources and assessment of their impacts on Class I areas at distances much greater than the limited CALPUFF model system and accounts for all the other known emissions sources in the modeling domain that results in varying background pollution levels temporally and spatially that individual source emissions interact. Furthermore, CAMx is also more suited than other possible modeling approaches for evaluating the visibility impacts of SO_2, NO_X, VOC, and PM emissions, as it has a more robust chemistry mechanism that is continually updated as the scientific community of peers agree on chemistry, physics, and structural upgrades. As such, CAMx provides a scientifically defensible platform for the assessment of visibility impacts over a wide range of source-to-receptor distances that has been used by a number of states in development of their Regional Haze SIPs, including Texas.

Since CAMx modeling differs in several ways from CALPUFF modeling, we are using different metrics to evaluate BART visibility impacts from CAMx. For CAMx modeling, we utilize the maximum daily impact as the primary metric for BART screening and assessment of visibility impacts as compared to the use of the 98th percentile metric with CALPUFF. As explained in the 2023 BART Modeling TSD, this approach recognizes differences in the models and model inputs and their application in determining whether the source is anticipated to cause or contribute to visibility impairment. For example, one difference is that compared to CALPUFF, CAMx utilizes a more robust chemistry mechanism, thus the primary concern that drove the selection of the 98th percentile value for CALPUFF based modeling are not applicable. Furthermore, because the CAMx modeling uses a more limited meteorological data period (one year of meteorology instead of three years used for CALPUFF modeling), and CAMx modeling also uses only one receptor for the Class I area[177] versus the many receptors covering the entire area of the Class I area that are used in CALPUFF modeling, the maximum of the daily impacts at a Class I area is appropriate for determining if a source is subject to BART. The use of the maximum value from CAMx also comports with TCEQ's use of the maximum value from CAMx modeling for BART screening that TCEQ included in the 2009 Texas Regional Haze SIP.[178,179] See the 2023 BART Modeling TSD for further discussion of the CALPUFF and CAMx modeling systems, the metrics evaluated, and the limitations and strengths of each modeling system.

For this proposed action, our CAMx modeling platform began with TCEQ's 2016 Modeling Platform,[180] namely TCEQ's 2016 emissions data, 2016 meteorological data, and other modeling files utilized in their CAMx modeling for TCEQ's Second Planning Period Texas

---

[177] For CAMx, we used the location coordinates of the 13 IMPROVE monitors that represent the 15 Class I areas, as was done in previous modeling. IMPROVE monitor GUMO1 represents both the Guadalupe Mountains NP and the Carlsbad Caverns NP Class I areas, and IMPROVE monitor WHPE1 represents both Wheeler Peak and Pecos Wilderness Areas Class I areas. IMPROVE monitors are part of a nationwide visibility monitoring network. The IMPROVE program establishes current visibility and aerosol conditions in mandatory Class I areas; identifies chemical species and emission sources responsible for existing man-made visibility impairment; documents long-term trends in visibility; and provides regional haze monitoring representing all visibility-protected federal Class I areas, where practical.

[178] *See* 2009 Texas Regional Haze 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. The EPA, the Texas Commission on Environmental Quality (TCEQ), and FLM representatives verbally approved the approach in 2006 and in email exchange with TCEQ representatives in February 2007 (*see* email from Erik Snyder (EPA) to Greg Nudd of TCEQ Feb. 13, 2007 and response email from Greg Nudd to Erik Snyder Feb. 15, 2007, available in the docket for this action).

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

[180] For this action, we used TCEQ's 2016 modeling platform from its Second Planning Period Regional Haze SIP revision. TCEQ submitted this Second Planning Period Regional Haze SIP revision to the EPA on July 20, 2021. The EPA has not reviewed this SIP nor proposed action on this SIP, but we are utilizing the modeling platform developed by TCEQ for this SIP to perform our modeling analyses to determine whether a source is subject to BART and in conducting the BART analysis for those sources determined to be subject to BART. The EPA will evaluate the Second Planning Period Regional Haze SIP submitted by TCEQ in a separate action. The SIP is available at https://www.tceq.texas.gov/airquality/sip/bart/haze_sip.html and in the docket for this action.

Regional Haze SIP. We are using this updated modeling platform to reflect more recent meteorology and emissions inventories and have identified it to be the best available platform for modeling these sources in Texas.[181] We upgraded this modeling platform to the newest version of the CAMx model, adjusted emissions for BART-eligible units, and utilized different/new Particulate Matter Source Apportionment Technology (PSAT)[182] categories (individual EGU units and facilities) to track source contributions for BART-eligible units. These adjustments are explained in more detail in the 2023 BART Modeling TSD.

Using the BART Guidelines recommended maximum daily emissions and post-processing approach, if the source (which is the aggregate of all BART-eligible units at a specific facility) is shown to contribute less than 0.5 dv to visibility impairment at all modeled Class I areas on all modeled days, then it is said to be "not subject to BART" and may be excluded from further steps in the BART process. The maximum modeled impact for each source, taking into account the annual average natural background conditions at the Class I areas, was compared to the 0.5 dv contribution threshold. See the 2023 BART Modeling TSD for additional details on the CAMx modeling.

2. Subject to BART Determinations Based on CALPUFF and CAMx Modeling Results

Table 3 shows the CALPUFF modeling results for the screening analysis. The Graham, Newman, Stryker Creek, and Wilkes BART-eligible units (all gas-fired or gas/fuel oil-fired BART-eligible units) that were included in the Texas SO_2 Trading Program can be exempted

[181] Consequently, a 2016-2018 period for CALPUFF modeling and 2016-2020 emissions would be consistent with this choice.
[182] CAMx includes an advanced mechanism that allows tracking the contributions of individual sources and pollutants within the grid model. For purposes of tracking particulate matter formation, we employed the CAMx PSAT for the BART-eligible sources included in the Texas SO_2 Trading Program, including the three coal-fired EGU sources that did not screen out with the CALPUFF modeling (Harrington, Martin Lake, and Welsh).

from further analysis because they all have modeled maximum 98th percentile annual impacts at all Class I areas of less than the 0.5 dv threshold. When considering impacts modeled using CALPUFF, a source is considered subject to BART if any of the three annual 98th percentile values are 0.5 dv or greater. As Table 3 shows, the coal-fired BART-eligible units at Martin Lake, Harrington, and Welsh did not screen out based on the CALPUFF modeling and thus are considered to cause or contribute to visibility impairment at Class I areas. See the 2023 BART Modeling TSD for this action for more details on the CALPUFF modeling and the modeling results.

Table 3: CALPUFF BART Screening Analysis

Plant Name	Operator Name	Boiler ID(s)	Most Impacted Class I Area (distance)	Maximum Delta Deciviews			Less than 0.5 dv
				2016	2017	2018	
Graham	Luminant	2	Wichita Mountains (174 km)	0.297	0.203	0.423	Yes
Newman	El Paso Electric	2, 3, **4, **5	Guadalupe Mountain (133 km)	0.342	0.368	0.354	Yes
Stryker Creek	Luminant	ST2	Caney Creek (283 km)	0.054	0.059	0.064	Yes
Wilkes Power Plant	AEP	1, 2, 3	Caney Creek (174 km)	0.380	0.373	0.442	Yes
Martin Lake	Luminant	1,2,3	Caney Creek (238 km)	3.28	3.60	3.35	No
Harrington	Xcel	061B, 062B	Salt Creek (305 km)	0.49	0.59	0.54	No
Harrington	Xcel	061B, 062B	Wichita Mountains (278 km)	0.54	0.45	0.58	No
Welsh	AEP	1	Caney Creek (161 km)	0.7	0.94	0.96	No

Table 4 summarizes the results of the CAMx screening analysis. These results also establish the baseline impacts for further modeling analyses of potential visibility benefits of controls. We note that all six sources analyzed with CAMx PSAT modeling had impacts greater than 0.5 dv at one or more Class I areas. Table 4 also shows that the CAMx-predicted visibility impacts range from 0.52 dv to 6.69 dv for these six sources at individual Class I areas on their maximum impact day. Additionally, Table 4 shows the number of days impacted over 0.5 dv and 1.0 dv at the maximum impacted Class I areas for each source. We note that maximum impacts from Fayette[183] are just above the 0.5 dv threshold and only exceed the threshold on one day. However, because the intent of the screening analysis is to be inclusive, we therefore consider Fayette subject to BART. The relatively lower visibility impacts and potential benefits from controls will be considered as part of the five-factor analysis when determining the potential availability of cost-effective emission reductions. With the exception of Fayette, the BART-eligible sources modeled using CAMx had maximum impacts well over the 0.5 dv threshold on multiple modeled days (ranging from 8 to 150 days).

Table 4: CAMx BART Screening Source Analysis Summary

BART-eligible source	Units	Most Impacted Class I area	Maximum delta-dv	Less than 0.5 dv?	Number of modeled days ≥0.5 dv[1]	Number of modeled days ≥1.0 dv[1]
Coleto Creek	1	Caney Creek	1.55	No	18	2
Fayette Power	1 & 2	Caney Creek	0.52	No	1	0
Harrington	061B & 062B	White Mountain	2.64	No	8	3
Martin Lake	1, 2, & 3	Caney Creek	6.69	No	150	101
W. A. Parish	WAP4, WAP5, & WAP6	Wichita Mountains	3.97	No	35	12
Welsh	1	Caney Creek	1.58	No	27	6

[1] Number of days over 0.5 or 1.0 dv at the most impacted Class I area. See Table 12 for cumulative results at the 15 Class I areas analyzed.

[183] Fayette Power Project is also known as Sam Seymour. We refer to it as Fayette throughout this document.

Based on the modeling analysis, the BART-eligible sources in Table 5 have been determined to cause or contribute to visibility impairment at a nearby Class I area; therefore, we propose to find the six sources are subject to BART. We must establish emission limits for visibility impairing pollutants SO_2 and PM through further evaluation using the BART five factor analysis.[184]

Table 5: Sources that are Subject-to-BART

Facility	Units
Coleto Creek	1
Fayette Power	1 & 2
Harrington	061B & 062B
Martin Lake	1, 2 & 3
W. A. Parish	WAP4, WAP5 & WAP6
Welsh	1

3. Subject to BART Determination for O.W. Sommers Units 1 and 2

CPS Energy operates the Calaveras Power Station which is comprised of O. W. Sommers Units 1 and 2, J. T. Deely Units 1 and 2,[185] and J. K. Spruce Units 1 and 2. In our 2017 Texas BART proposal, we identified O. W. Sommers Units 1 and 2 and J. T. Deely Units 1 and 2 as BART-eligible and conducted CAMx modeling to determine their visibility impacts. Because J. T. Deely Units 1 and 2 subsequently ceased operation and shut down, our analysis in this action is limited to the two gas-fired units at O. W. Sommers. Given the retirement of the two coal-fired units at J. T. Deely and the low SO_2 emissions from the O. W. Sommers gas-fired EGUs, rather

[184] The NO_X BART requirement for these EGU sources is not addressed by source-specific limits in this proposal. The EPA's determination that Texas' participation in CSAPR for ozone-season NO_X satisfies NO_X BART for EGUs was finalized in our October 17, 2017 final rule (82 FR 48324), thus dispensing with the need for source-specific BART determinations and requirements for NO_X. We did not reopen that determination in our August 2018 proposal, November 2019 supplemental proposal, or August 2020 final rule, and are not reopening it in this proposal.

[185] Acosta, Sarah (January 3, 2019). "CPS Energy closes coal-fired Deely plant in operation since '70s to focus on cleaner energy sources". KSAT-TV. Retrieved January 4, 2019.

than conducting new CAMx modeling, we updated our analysis of O. W. Sommers Units 1 and 2 relying on the CAMx modeling from our 2017 Texas BART proposal (further referred to as 2017 Proposal). In that analysis, we conducted CAMx modeling using the combined maximum 24-hour emissions from both J. T. Deely Units 1 and 2 and O. W. Sommers Units 1 and 2 to determine if the aggregate BART-eligible source (all four BART-eligible units at Calaveras Power Station) was subject to BART. The maximum modeled impact from the Calaveras Power Station was 1.513 dv. As documented in the BART Screening TSD and associated supporting documents for the 2017 BART FIP,[186] the impacts of the two O. W. Sommers BART-eligible units were previously estimated to have a maximum visibility impact of 0.286 dv at the Caney Creek Class I area, which is below the 0.5 dv threshold.[187]

To bolster our current analysis, we also compared the modeled SO_2 and NOx emission rates from the O. W. Sommers units with the recent maximum daily emissions from 2016-2020. Sulfate and nitrate made up almost all of the extinction value on the maximum impact day at Caney Creek Class I area, with approximately 89 percent of the total extinction from nitrates and 9 percent from sulfates on the maximum impact day due to emissions from O.W. Sommers. Because the two O. W. Sommers BART-eligible units are located near each other and have similar stack parameters, we used a linear adjustment comparing emissions modeled previously to more recent emissions (2016 - 2020) to provide an estimate of current visibility impact. While

[186] "Technical Support Document Our Strategy for Assessing which Units are Subject to BART for the Texas Regional Haze BART Federal Implementation Plan (BART Screening TSD), pdf page 72 and Appendix E, available in the docket EPA-R06-OAR-2016-0611 (at EPA-R06-OAR-2016-0611-0005).

[187] Id. pdf page 72 and Appendix E. CAMx Maximum Impact at each Class Area; The O. W. Sommers BART-eligible units were modeled individually, the sum (maximum dv impacts) of which is0.286 dv. Adding the maximum impacts of each unit results in a slight overestimation of the visibility impacts, since we did not first calculate total extinction and then dv, which is a natural logarithmic function. Therefore 0.286 dv is conservative (higher than if modeled).

linear scaling does not result in the same values as modeling, it is a reasonable methodology to conservatively approximate the visibility impact from a source.

Table 6 compares the NOx and SO_2 emission rates modeled in the 2017 Proposal to the maximum daily emission rates of NO_X and SO_2 from the 2016-2020 period.[188, 189] We did not compare PM_{10} or $PM_{2.5}$ as they were less than 3 percent of the total light extinction on the maximum impact day. SO_2 emissions from the 2016-2020 period were less than 3 percent of what was previously modeled, and NOx emissions were 13.71 percent higher than what was modeled for our 2017 Proposal for these two units. Acknowledging that the reduction in SO_2 emissions will result in lower visibility impact, we choose to not adjust for the lower SO_2 emissions in an effort to be conservative in our analysis. Scaling the 2017 visibility impact (0.286 dv at Caney Creek Class I area) linearly to account for the 13.71 percent total increase in NOx emissions, we estimate a maximum visibility impact of 0.325 dv at the Caney Creek Class I area, which is well below the 0.5 dv threshold. Based on this analysis, it is reasonable to conclude that if emissions from the two O. W. Sommers BART-eligible units were remodeled using recent emissions, it would result in a maximum visibility impact less than 0.5 dv and would screen out of further analysis. Therefore, the EPA proposes that O. W. Sommers Units 1 and 2 are not subject to BART.

Table 6. O. W. Sommers BART-Eligible Units Emissions Modeled in 2017 vs. Recent 2016-2020 Emissions.

	O. W. Sommers Modeled in 2017 Proposal (TPD)			**O. W. Sommers Max Daily Emissions 2016-2020 (TPD)**			**2016-2020 Total as percentage of 2017 Modeled**
	Unit 1	Unit 2	**Total**	Unit 1	Unit 2	**Total**	

[188] *Id.* Appendix A. Modeled parameters: Stack and emissions for CAMx modeled sources for modeled emissions in 2017 proposal.
[189] https://campd.epa.gov/.

SO2	2.01	10.92	12.93	0.167	0.147	0.31	2.43%
NOx	5.96	8.04	14.00	9.32	6.6	15.92	113.71%

B. BART Five Factor Analysis

The purpose of the BART analysis is to identify and evaluate the best system of continuous emission reduction based on the BART Guidelines.[190] In determining BART, a state, or the 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 non-air quality environmental impacts of compliance; (3) any existing pollution control technology in use at the source; (4) the remaining useful life of the source; and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. 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 into five steps:[191]

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. Step 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

[190] *See* July 6, 2005 BART Guidelines, 40 CFR Part 51, Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations.
[191] 70 FR 39104, 39164 (July 6, 2005) [40 CFR Part 51, App. Y].

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.[192]

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. We will also note whether any of these technologies are technically infeasible.

The subject-to-BART units identified in Table 5 can be organized into three broad categories, based on their fuel type and the potential types of SO_2 control options that could be available: (1) coal-fired EGUs with no SO_2 scrubber, (2) coal-fired EGUs with existing SO_2 scrubbers, and (3) gas-fired EGUs that do not burn oil. This classification is represented in Table 7.

Table 7: Fuel/Control Types for Subject-to-BART Sources

Facility	**Unit**	**Coal (no scrubber)**	**Coal (existing scrubber)**	**Gas**
Coleto Creek (Dynegy)	1	X		
Fayette (LCRA)	1		X	
Fayette (LCRA)	2		X	
Harrington Station (Xcel)	061B	X		
Harrington Station (Xcel)	062B	X		
Martin Lake (Luminant)	1		X	
Martin Lake (Luminant)	2		X	
Martin Lake (Luminant)	3		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		

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) dry Flue Gas

[192] 70 FR at 39164, fn 12 [40 CFR Part 51, App. Y].

Desulfurization (FGD), and (4) wet FGD. For the coal-fired EGUs with existing scrubbers, we will examine whether those scrubbers can be upgraded.

Gas-fired EGUs that do not burn oil (W. A. Parish Unit WAP4) have inherently very low SO_2 emissions and there are no known SO_2 controls that can be evaluated.

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 by 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 sulfur in the product coal).[193] 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.[194] Coal is mechanically sized, then various washing techniques are employed, depending on the particle size, type of coal, and the desired level of

193 Couch, G. R., "Coal Upgrading to Reduce CO_2 emissions," CCC/67, October 2002, IEA Clean Coal Centre.
194 *Id.*

preparation.[195] 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. 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.
- 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,[196] and coal washing slurries are typically stored in impoundments, which can, and have, leaked.[197]

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., iron pyrite) and rocks, and (2) the unit burning less coal to make the same amount of power.

---

[195] 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.

[196] "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.

[197] 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.

Coal drying could be considered a potential BART control. Great River Energy has developed a patented process which is being successfully utilized at the Coal Creek facility in North Dakota and is potentially available for installation at other facilities.[198] 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. Coal Creek units also utilize wet FGD to reduce SO_2 emissions. Therefore, the observed additional SO_2 emission reductions are due to the combination of a higher percentage of flue gas being scrubbed (decreased bypass of the wet FGD) in combination with a decrease in coal usage and any removal of sulfur in the drying process. We are not aware of any other EGUs in the United States that utilize coal drying for the purpose of reducing SO_2 emissions. Therefore, we believe coal drying has limited application at EGUs in the United States.

Although coal drying may be a potential option 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 several 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). As a result of these issues, we do not further assess coal drying as part of our reasonable set of options for BART analysis.

DSI

---

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

DSI is not a stand-alone, add-on air pollution control system but a modification to the combustion unit or ductwork. 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. In general, there are many types of sorbent materials, but their efficacy is variable and dependent on operating conditions. Trona is currently the most commonly used sorbent for SO_2 removal and is 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 that is more frequently used for acid gas control.[199,200]

There are many examples of DSI being used on coal-fired EGUs. However, DSI may not be technically feasible at every coal-fired EGU. For example, DSI technology is not a technically feasible control option for boilers that burn fuels with sulfur content greater than 2 lb SO_2/MMBtu.[201] Although individual installations may present technical difficulties or poor performance due to the suboptimization of operational factors, we believe that DSI may be a particularly appropriate SO_2 control option for boilers that burn low-sulfur coal or lignite, as such boilers typically do not need SO_2 controls with very high control efficiencies (i.e., greater

---

[199] *See* Documentation for the EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, dated September 2021, page 5-19. Documentation for v.6 downloaded from https://www.epa.gov/power-sector-modeling/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference.

[200] "Dry Sorbent Injection of Sodium Sorbents," presented at the LADCO Lake Michigan Air Directors Consortium, Emission Control and Measurement Technology for Industrial Sources Workshop, March 24, 2010. A copy of the presentation is located in the docket at EPA-R06-OAR-2016-0611-0043.

[201] IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology, Final April 2017, Project 13527-001, Eastern Research Group, Inc., Prepared by Sargent & Lundy, page 3. Documentation for v.6: Chapter 5: Emission Control Technologies, Attachment 5-5: DSI Cost Methodology, downloaded from https://www.epa.gov/sites/default/files/2018-05/documents/attachment_5-5_dsi_cost_development_methodology.pdf.

than 95 percent) to achieve low emission rates. Because the Texas coal-fired EGUs we are evaluating in this proposal burn low-sulfur coal, we find that they are well suited for consideration of DSI for SO_2 control. Additionally, boilers that operate DSI and burn low-sulfur coal require much less sorbent than boilers burning high-sulfur coal to achieve similar control efficiencies. We also note that DSI is a common control technology that has been widely installed for compliance with the acid gas control requirements in the Mercury and Air Toxics Standards (MATS).[202] For these reasons, we find 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 (typically lime or limestone) 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 dry FGD. The U.S. Energy Information Administration (EIA) reports[203] the following types of flue gas desulfurization systems as being operational in the U.S. for 2020:

Table 8: EIA Reported Desulfurization Systems in 2020

Type	Number of installations
Wet spray tower scrubber	288
Spray dryer absorber	256
Circulating dry scrubber	41
Packed tower wet scrubber	4

[202] The MATS rule was finalized by the EPA in December 2011, and compliance with the standard was required by 2015. The MATS rule requires that plants greater than 25 megawatts meet the maximum achievable control technology for mercury, hydrochloric acid, and filterable particulate matter (note the MATS rule does not require controls for SO_2). *See* https://www.epa.gov/mats/regulatory-actions-final-mercury-and-air-toxics-standards-mats-power-plants.

[203] *See* EIA-860 data available here: https://www.eia.gov/electricity/data/eia860/.

Venturi wet scrubber	58
Jet bubbling reactor	23
Tray tower wet scrubber	63
Mechanically aided wet scrubber	4
DSI	149
Other	36
Unspecified	0
Total	922

Excluding the DSI installations,[204] EIA lists 773 SO_2 scrubber installations in operation in 2020. Of these, 288 are listed as being spray type wet scrubbers, with an additional 63 listed as being tray type wet scrubbers.[205] An additional 256 are listed as being spray dry absorber (SDA) scrubbers, which are a type of dry FGD. Consequently, spray type or tray type wet scrubbers (wet FGD) account for approximately 45 percent of all scrubber systems, and SDA accounts for approximately 33 percent of all scrubber systems that were operational in the U.S. in 2020.

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. Circulating dry scrubbers (CDS) is another type of dry scrubbing system that can achieve high removal efficiencies but has seen more limited use in the United States compared to SDA.[206] Based on available data, CDS systems have installed costs that are comparable to SDA

[204] As discussed in this section, DSI is more commonly installed for compliance with the acid gas control requirements for MATS, not for meeting SO reduction requirements.
[205] Trays are often employed in spray type wet scrubbers and EIA lists some of the wet spray tower systems as secondarily including trays.
[206] *See* the EPA Air Pollution Control Cost Manual, Seventh Edition (April 2021), Section 5, Chapter 1, page 1-44. The EPA Air Pollution Control Cost Manual is available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual. The EPA is currently in the process of updating the Control Cost Manual and this update will be the Seventh Edition. Although updates are not yet complete for all sections the EPA intends to update in the Seventh Edition, updated Section 5, Chapter 1, which is titled "Wet and Dry Scrubbers for Acid Gas Control," is now available and is part of the Seventh Edition of the Control Cost Manual.

systems even though there are differences in design.[207] CDS systems may be capable of achieving a slightly higher control efficiency than SDA, but based on 2019 data for coal-fired units at power plants, the 12-month average emission rate for the top performing 50 percent FGD systems is 0.06 lb/MMBtu for SDA systems and 0.12 lb/MMBtu for CDS systems.[208]

The BART Guidelines explain that:

> A possible outcome of the BART procedures discussed in these guidelines is the evaluation of multiple control technology alternatives which result in essentially equivalent emissions. It is not our intent to encourage evaluation of unnecessarily large numbers of control alternatives for every emissions unit. Consequently, you should use judgment in deciding on those alternatives for which you will conduct the detailed impacts analysis (Step 4 below).[209]

We believe that evaluation of SDA and wet FGD covers a reasonable range of control efficiencies offered by available SO_2 scrubbing technologies and includes the most stringent control option available.[210] CDS will not be further considered as part of our reasonable set of options for analysis for BART controls given the similarity in cost and removal efficiencies with SDA. However, CDS could potentially be considered as an alternative dry scrubber control to SDA. We therefore solicit comment regarding costs and control efficiency of CDS, including comments from the facilities we evaluated for SO_2 scrubbers on whether they have conducted

---

[207] *See* Control Cost Manual, Wet and Dry Scrubbers for Acid Gas Control Response to Comment Document, pg 32. Available at chrome-extension://efaidnbmnnnibpcajpcglclefindmkaj/https://www.epa.gov/sites/default/files/2021-05/documents/rtcdocument_wet_and_dry_scrubbers_controlcostmanual_7thedition.pdf and in the docket for this action.

[208] The EPA Air Pollution Control Cost Manual (the Control Cost Manual, or Manual), Seventh Edition (April 2021), Section 5, Chapter 1 titled "Wet and Dry Scrubbers for Acid Gas Control," page 1-12. The Control Cost Manual can be found at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual.

[209] See 40 C.F.R. Part 51, Appendix Y – Guidelines For BART Determinations Under the Regional Haze Rule, Section IV.D.2.

[210] The EPA Air Pollution Control Cost Manual (the Control Cost Manual, or Manual), Seventh Edition (April 2021), Section 5, Chapter 1 titled "Wet and Dry Scrubbers for Acid Gas Control" provides data summarizing the efficiency and SO_2 emission rates for SO_2 scrubbers based on 2019 data for coal-fired units at power plants. The 12-month average emission rate for the top performing 50 percent FGD systems is 0.04 lb/MMBtu for limestone wet FGD systems, 0.06 lb/MMBtu for SDA systems, and 0.12 lb/MMBtu for CDS systems. (See page 1-12). The Control Cost Manual can be found at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual.

analysis of CDS, the level of SO_2 control efficiency that could be achieved with installation of CDS at the unit, and the estimated cost of that control technology at the unit.

Wet FGD and SDA installations account for approximately 79 percent 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. Based on typical SDA performance, SDA scrubbers should not be applied to boilers that burn fuels with more than 3 lb SO_2/MMBtu.[211] Typically, SDA technology has been applied to boilers that burn fuels with less than 2 lb/MMBtu. The Texas coal-fired EGUs we are evaluating in our BART analyses burn low sulfur coal and are suitable for evaluation of both SDA and wet FGD. We see no technical infeasibility issues and believe that limestone wet FGD and lime SDA should be considered as potential BART controls for all unscrubbed coal-fired subject to BART units. However, due to potential non-air quality concerns associated with water availability, we limit our SO_2 control analysis for Harrington Units 061B and 062B to DSI and SDA. This is discussed in more detail in Section VII.B.3.

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

In our 2016 Texas-Oklahoma FIP,[212] we presented a great deal of information on which we reached a conclusion that the existing scrubbers for a number of facilities could be very cost-

[211] IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, Final January 2017, Project 13527-001, Eastern Research Group, Inc., Prepared by Sargent & Lundy, p. 2.
[212] 81 FR 296, 321 (Jan. 5, 2016).

effectively upgraded.[213] While that action was stayed by the Fifth Circuit, the basis for the stay was not related to that technical analysis. This information remains valid and can be used to inform our BART analysis in this proposal. Therefore, we have included this information in the record for this proposal in Appendix A of the 2023 BART FIP TSD in the docket.[214] Appendix A also contains a comprehensive survey we prepared as part of our 2016 Texas-Oklahoma FIP 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 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 previous CAA 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 C.F.R. § 2.203(b). We therefore redacted any CBI information we utilized in our analyses, or otherwise disguised it so that it cannot be traced back to its specific source. Based on our review of this information, we find that upgrades to the existing scrubbers should be considered as potential BART controls for the three subject-to-BART units at the Martin Lake facility.

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 Boiler Operating Day (BOD) average below 0.04 lb/MMBtu for years at a time.[215] As we discuss in Section VII.B.2.a, we state that

[213] *See* information presented in Sections 6 and 7 of the 2016 Texas-Oklahoma FIP Cost TSD, Document No. EPA-R06-OAR-2014-0754-0008, available at www.regulations.gov.
[214] *See* our 2023 BART FIP TSD, Appendix A, "Wet FGD Scrubber Upgrade Control Analysis as used in the Texas-Oklahoma FIP."
[215] *See* our 2023 BART FIP TSD for additional information and graphs of this data.

retrofit wet FGDs should be evaluated at 98 percent control not to go below 0.04 lb/MMBtu. Because the Fayette units are already performing at this level, we do not evaluate any additional scrubber upgrades for these two units. Thus, our SO_2 BART analysis in this proposed rulemaking evaluates scrubber upgrades as potential BART controls only for Martin Lake Units 1, 2, and 3.

c. Identification of Technically Feasible SO_2 Control Technologies for Gas Fired Units

Based on our subject to BART screening analysis, W. A. Parish Unit WAP4 is the only gas-fired unit we determined to be subject to BART. Because the BART screening analysis is done on a facility-wide basis, Unit WAP4 is only subject to BART because it is collocated with two BART-eligible coal-fired units. Gas-fired EGUs have inherently low SO_2 emissions[216] and there are no known SO_2 controls that can be evaluated. While we must assign SO_2 BART determinations to the gas-fired unit, there are no practical add-on controls to consider for setting a more stringent BART emission 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.[217] As there are no appropriate add-on controls and the status quo reflects the most stringent control level, we are proposing that SO_2 BART for W. A. Parish Unit WAP4 is to limit fuel to pipeline natural gas, as defined at 40 CFR 72.2.[218]

2. Step 3: Evaluation of Control Effectiveness

In the following subsections, we evaluate the control levels each technically feasible technology can achieve for the coal units. In so doing, we consider the maximum level of control

[216] 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.
[217] 70 FR at 39165 (''. . . you may skip the remaining analyses in this section, including the visibility analysis . . .'').
[218] As provided for in 40 CFR 72.2, pipeline natural gas contains 0.5 grains or less of total sulfur per 100 standard cubic feet. This is equivalent to an SO_2 emission rate of 0.0006 lb/MMBtu.

each technology is capable of delivering based on a 30 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."[219] 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.

a. Evaluation of SO_2 Control Effectiveness for Coal-fired Units Without an Existing Scrubber

Control Effectiveness of DSI

DSI involves pneumatically injecting a sorbent either directly into a coal-fired boiler or into ducting downstream of where the coal is combusted. The sorbent interacts with various pollutants in the flue gas, including SO_2 and acid gases such as hydrochloric acid (HCl), such that a fraction of these pollutants are removed from the gas stream. After the appropriate chemical interactions between the sorbent and the pollutants in the flue gas, the dry waste product of the reaction is removed using a particulate control device, typically a fabric filter baghouse or electrostatic precipitator (ESP). The SO_2 removal efficiency of DSI varies greatly but is highly dependent on the following factors: the type of sorbent used; the careful balancing of the stoichiometry of the molecules in the sorbent (sodium in the case of trona or sodium bicarbonate, or calcium in the case of hydrated lime) and SO_2 molecules in the flue gas; and the type of particulate capture device used in conjunction with the sorbent injection. Removal efficiency can also be improved by increasing the surface area of the sorbent to increase reactivity with the SO_2 gas. This can be achieved by crushing or "milling" the sorbent and also

---

[219] 70 FR 39103, 39172 (July 6, 2005), [40 CFR Part 51, App. Y].

by applying heat. Both the application of heat and milling the sorbent increase the efficiency of the DSI system, but also increase the cost.[220]

The most common sodium-based sorbents used in DSI systems are trona and sodium bicarbonate. Sodium bicarbonate is more effective in removing SO_2 emissions than trona,[221] and therefore, less sodium bicarbonate is needed for an equivalent amount of SO_2 removal compared to trona. However, sodium bicarbonate is more expensive than trona on a per ton basis. Hydrated lime is a calcium-based sorbent that is also used in DSI systems. DSI using hydrated lime typically achieves a lower SO_2 removal efficiency compared to DSI using trona. Aside from the lower SO_2 removal efficiency typically seen with hydrated lime, we also note that DSI using hydrated lime as the sorbent may necessitate the use of a baghouse rather than an ESP as the particulate capture device, which would increase costs if a unit does not already have an existing baghouse. Because trona is generally considered the most cost-effective of the DSI sorbents for SO_2 removal and considering the limitations associated with hydrated lime for SO_2 removal, our DSI analysis is based on using milled trona as the sorbent.[222]

In developing our BART analysis for DSI, we relied on the EPA's April 2017 version of the Integrated Planning Model (IPM) DSI documentation[223,224] and the 2019 version of the

---

220 IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology, Final April 2017, Project 13527-001, Eastern Research Group, Inc., Prepared by Sargent & Lundy.

221 Sodium bicarbonate may be able to achieve even higher SO_2 removal efficiencies compared to trona. However, the April 2017 IPM DSI documentation and associated 2019 Retrofit Cost Analyzer (RCA) tool cost spreadsheet do not include information on sodium bicarbonate costs and removal efficiencies.

222 As discussed in the preceding paragraph, the removal efficiency of trona can be improved by crushing or "milling" the sorbent, which increases the reactivity with the SO_2 gas. The control efficiencies we evaluate for DSI and our cost analysis is based on the use of milled trona.

223 *See* Documentation for the EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, dated September 2021. Documentation for v.6 downloaded from https://www.epa.gov/power-sector-modeling/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference.

224 IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology, Final April 2017, Project 13527-001, Eastern Research Group, Inc., Prepared by Sargent & Lundy. Documentation for v.6: Chapter 5: Emission Control Technologies, Attachment 5-5:

EPA's Retrofit Cost Analyzer (RCA), which is an Excel-based tool that can be used to estimate the cost of building and operating air pollution controls and also employs version 6 of our IPM model.[225] We expect that by the time this proposal is published in the Federal Register, or shortly thereafter, the EPA will have issued an updated version of the IPM DSI documentation and an accompanying updated version of the RCA tool for calculating the cost of DSI. The updated IPM DSI documentation and updated RCA tool for DSI include a number of updates to the cost algorithms and updated estimates for sorbent costs. Initial review of the updated DSI documentation indicates the maximum potential SO_2 control efficiencies of DSI may be higher than indicated in the April 2017 version of the IPM DSI documentation. The updated DSI documentation and RCA tool also include updated cost algorithms predicting the amount of sorbent required to achieve certain control efficiencies that generally result in similar cost effectiveness values ($/ton) for DSI using milled trona compared to the cost algorithms used in the April 2017 version of the IPM DSI documentation and the 2019 version of the RCA tool. This is the result of the updated efficiency curves estimating lower sorbent use and updated higher costs for milled trona. The updated RCA tool contains cost information for sodium bicarbonate and the capability to estimate the cost of DSI using sodium bicarbonate as the sorbent. In general, the cost-effectiveness values for DSI using milled trona and sodium bicarbonate appear to be very similar. Less sodium bicarbonate is needed than milled trona to achieve a given control efficiency but the cost per ton of sodium bicarbonate is higher compared to milled trona, thereby resulting in similar cost-effectiveness values. However, the updated IPM DSI documentation indicates that sodium bicarbonate may be able to achieve higher control

DSI Cost Methodology, downloaded from https://www.epa.gov/sites/default/files/2018-05/documents/attachment_5-5_dsi_cost_development_methodology.pdf.
[225] Retrofit Cost Analyzer, rev: 06-04-2019, downloaded from https://www.epa.gov/power-sector-modeling/retrofit-cost-analyzer.

efficiencies compared to milled trona. We will include these documents in the docket once they are finalized and made publicly available. As these updated documents were not available at the time we developed our cost analysis, we did not rely on this updated information in our DSI cost analysis presented in this proposal. In general, the updated IPM DSI documentation and updated RCA tool for DSI suggest that DSI could potentially achieve higher SO_2 control efficiencies at a similar cost per SO_2 tons removed. However, as described in further detail below, absent site-specific information from the facilities that we evaluated for DSI, we believe there is uncertainty whether these units are capable of achieving the assumed maximum DSI performance levels specified in either the April 2017 IPM DSI documentation or the updated version of the IPM DSI documentation. Similarly, we believe that our concern regarding the uncertainty in the cost estimates for DSI at high SO_2 removal levels would still exist even if we were to rely on the updated versions of the IPM DSI documentation and the RCA tool.[226] However, as we discuss later in this subsection, we solicit comment on the range and maximum control efficiency that can be achieved with DSI at the evaluated units and estimates of the range of associated costs. We are especially interested in any site-specific analysis of DSI for the units we evaluated, the level of SO_2 control efficiency that could be achieved with installation of DSI at these units, and the estimated cost of that control technology at these units.

According to the April 2017 IPM DSI documentation, the assumed maximum DSI performance level using milled trona is 80 percent SO_2 removal for an Electrostatic Precipitator (ESP) installation and 90 percent SO_2 removal for a baghouse installation.[227] The BART

[226] We discuss these issues in more detail in Sections VII.B.3.a and VIII.A.
[227] IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology, Final April 2017, Project 13527-001, Eastern Research Group, Inc., Prepared by Sargent & Lundy. Documentation for v.6: Chapter 5: Emission Control Technologies, Attachment 5-5: DSI Cost Methodology, downloaded from https://www.epa.gov/sites/default/files/2018-05/documents/attachment_5-5_dsi_cost_development_methodology.pdf.

Guidelines state the following regarding selection of an emissions performance level or levels to evaluate in a BART analysis for a control option with a wide range of emission performance levels:

> It is not our intent to require analysis of each possible level of efficiency for a control technique as such an analysis would result in a large number of options. It is important, however, that in analyzing the technology you take into account the most stringent emission control level that the technology is capable of achieving. You should consider recent regulatory decisions and performance data (e.g., manufacturer's data, engineering estimates and the experience of other sources) when identifying an emissions performance level or levels to evaluate.[228]

Adhering to this, we are evaluating each unit at its assumed maximum achievable DSI performance level according to the April 2017 IPM DSI documentation. All the units we are evaluating for DSI controls have existing baghouses with the exception of Harrington Unit 061B, which has an ESP. For Coleto Creek Unit 1 and W. A. Parish Units WAP5 and WAP6, we are evaluating DSI at 90 percent SO_2 removal. For Welsh Unit 1 and Harrington Unit 062B, we are limiting the upper DSI control to their equivalent SDA control efficiencies of 87 percent and 89 percent, respectively. For Harrington Unit 061B, the only unit with an existing ESP, we are evaluating DSI at 80 percent SO_2 removal.

We recognize that there is some variation based on facility-specific circumstances which could affect whether a given unit is actually capable of achieving these assumed maximum performance levels. There is typically a direct correlation with DSI between the targeted SO_2 removal efficiency and the amount of sorbent needed; therefore, more sorbent is needed to reach higher SO_2 removal efficiencies. However, the reaction between the sorbent and the various pollutants in the flue gas results in a dry waste product that must be removed using a particulate

[228] *See* 40 C.F.R. Part 51, Appendix Y – Guidelines For BART Determinations Under the Regional Haze Rule, Section IV.D.3.

control device. As additional sorbent is added to achieve higher SO_2 removal efficiencies, the increased dry waste product can impact the performance of the particulate control device. For instance, DSI using trona and an ESP for capture of the dry waste product typically can achieve 40 – 50 percent SO_2 removal efficiency without an increase in particulate emissions.[229] At higher SO_2 removal efficiencies, however, depending on the throughput capacity, an ESP may not be able to handle the increased dry waste product. Similar issues exist where DSI is used with a fabric filter for capture of the dry waste product. The increased dry waste product produced in trying to achieve high SO_2 removal efficiencies would result in the more rapid formation of baghouse filter cake, which is the mixture of fly ash and sorbent-SO_2 reaction product. This would result in the need for more frequent cleaning, more rapid filter bag wear, and more frequent replacement of filter bags. The frequent need to clean and replace the filter bags may become impractical and additional fabric filter compartments may need to be added to handle the high loading that occurs at high SO_2 removal efficiencies. The exact SO_2 removal efficiency at which these secondary impacts would become significant is typically site-specific. As we discuss in Section VII.B.3.a, these secondary impacts associated with trying to achieve higher SO_2 removal efficiencies also lead to some uncertainty in our cost estimates for DSI at high SO_2 removal efficiencies.

Site-specific information based on individual performance testing is typically needed to be able to accurately determine the maximum DSI SO_2 removal efficiency for a particular unit. We do not have this site-specific information and testing for the individual units that we are

---

[229] IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology, Final April 2017, Project 13527-001, Eastern Research Group, Inc., Prepared by Sargent & Lundy. Documentation for v.6: Chapter 5: Emission Control Technologies, Attachment 5-5: DSI Cost Methodology, p. 3; downloaded from https://www.epa.gov/sites/default/files/2018-05/documents/attachment_5-5_dsi_cost_development_methodology.pdf.

evaluating for DSI. Instead, we analyzed publicly available 2017–2021 data for coal-fired EGUs with existing DSI systems and estimated the monthly average SO_2 removal efficiency of existing DSI systems by utilizing the reported sulfur content and tonnages of the fuels burned and reported to EIA[230] and the monitored SO_2 outlet emissions reported to the EPA.[231] Based on our analysis, we found that there is a large range of SO_2 removal efficiency at the coal-fired EGUs with existing DSI for which there is publicly available data. However, unless there is a specific regulatory requirement to meet a low SO_2 emissions rate, DSI installations are often not optimized to achieve the highest possible SO_2 control efficiency. Of particular interest for this BART analysis, there are existing coal-fired DSI units that are consistently achieving high monthly average SO_2 removal efficiencies in the 70–90 percent range. We discuss this analysis in further detail in our 2023 BART FIP TSD in the docket. However, because we could only identify a few cases where units are consistently achieving greater than 70 percent SO_2 control efficiency and, most importantly, because we do not have the site-specific information and individual performance testing needed to accurately determine the maximum DSI SO_2 removal efficiency for a particular unit, we do not know whether the EGUs we are evaluating in this proposal are capable of achieving the assumed maximum DSI performance levels specified in the April 2017 IPM DSI documentation or what level of control should be considered the maximum achievable level for these units.

Recognizing that DSI has a wide range of SO_2 removal efficiencies, that there is some variation based on facility-specific circumstances which could affect whether a given unit is actually capable of achieving the assumed maximum achievable control levels outlined in the April 2017 IPM DSI documentation, and because we believe it is useful to evaluate lesser levels

---

[230] EIA Form 923. Available at https://www.eia.gov/electricity/data/eia923/.
[231] EPA Air Markets and Programs Data. Available at https://campd.epa.gov/.

of DSI control to provide a range of costs, we will also evaluate these units at a DSI SO_2 control level that can likely be achieved by most coal-fired units. DSI using trona and an ESP for particulate capture can typically remove 40–50 percent of SO_2 without affecting the performance of the particulate control device.[232] Therefore, we believe 50 percent SO_2 removal is a conservatively low DSI control efficiency that any given coal-fired EGU is likely capable of achieving without requiring high sorbent injection rates that may negatively impact the particulate control. This approach is consistent with the BART Guidelines, which state the following:

> You may encounter cases where you may wish to evaluate other levels of control in addition to the most stringent level for a given device. While you must consider the most stringent level as one of the control options, you may consider less stringent levels of control as additional options. This would be useful, particularly in cases where the selection of additional options would have widely varying costs and other impacts.[233]

We invite comments on the range and maximum control efficiency that can be achieved with DSI at the evaluated units. We are especially interested in any site-specific DSI testing for the units we evaluated to determine the range and maximum control efficiency that can be achieved at those units. Any data to support the range and maximum control efficiency for a particular unit should be submitted along with those comments. We will further consider DSI site-specific information provided to us during the public comment period in making our final decision and potentially re-evaluate DSI and the control efficiency for one or more particular units.

---

[232] IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology, Final April 2017, Project 13527-001, Eastern Research Group, Inc., Prepared by Sargent & Lundy. Documentation for v.6: Chapter 5: Emission Control Technologies, Attachment 5-5: DSI Cost Methodology, p. 3; downloaded from https://www.epa.gov/sites/default/files/2018-05/documents/attachment_5-5_dsi_cost_development_methodology.pdf.

[233] *See* 40 C.F.R. Part 51, Appendix Y – Guidelines For BART Determinations Under the Regional Haze Rule, Section IV.D.3.

Control Effectiveness of Wet FGD and SDA

We have assumed a wet FGD level of control to be a maximum of 98 percent not to go below 0.04 lb/MMBtu, in which case, we assume the percentage of control equal to 0.04 lb/MMBtu. As we discuss later in this proposal, we conducted our wet FGD control cost analysis using the EPA's "Air Pollution Control Cost Estimation Spreadsheet For Wet and Dry Scrubbers for Acid Gas Control,"[234] which employs version 6 of our IPM model.[235] 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 percent 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."[236] The most recent version of the EPA Air Pollution Control Cost Manual (the Control Cost Manual, or Manual) section on Wet and Dry Scrubbers for Acid

---

[234] Air Pollution Control Cost Estimation Spreadsheet For Wet and Dry Scrubbers for Acid Gas Control, U.S. Environmental Protection Agency, Air Economics Group, Health and Environmental Impacts Division, Office of Air Quality Planning and Standards (January 2023), downloaded from https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

[235] *See* Documentation for the EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, dated September 2021. Documentation for v.6 downloaded from https://www.epa.gov/power-sector-modeling/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference.
IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology, Final April 2017, Project 13527-001, Eastern Research Group, Inc., Prepared by Sargent & Lundy. Documentation for v.6: Chapter 5: Emission Control Technologies, Attachment 5-5: DSI Cost Methodology, downloaded from https://www.epa.gov/sites/default/files/2018-05/documents/attachment_5-5_dsi_cost_development_methodology.pdf.
IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, Final January 2017, Project 13527-001, Eastern Research Group, Inc., Prepared by Sargent & Lundy. Documentation for v.6: Chapter 5: Emission Control Technologies, Attachment 5-2: SDA FGD Cost Methodology, downloaded from https://www.epa.gov/sites/default/files/2018-05/documents/attachment_5-2_sda_fgd_cost_development_methodology.pdf.
IPM Model – Updates to Cost and Performance for APC Technologies, Wet FGD Cost Development Methodology, Final January 2017, Project 13527-001, Eastern Research Group, Inc., Prepared by Sargent & Lundy. Documentation for v.6: Chapter 5: Emission Control Technologies, Attachment 5-1: Wet FGD Cost Methodology, downloaded from https://www.epa.gov/sites/default/files/2018-05/documents/attachment_5-1_wet_fgd_cost_development_methodology.pdf.

[236] IPM Model – Updates to Cost and Performance for APC Technologies, Wet FGD Cost Development Methodology, Final January 2017, Project 13527-001, Eastern Research Group, Inc., Prepared by Sargent & Lundy, p. 2.

Gas Control[237] provides data summarizing the efficiency and SO_2 emission rates for SO_2 scrubbers based on 2019 data for coal-fired units at power plants. The 12-month average emission rate for the top performing 50 percent of wet limestone FGD systems is 0.04 lb/MMBtu.[238]

Assuming a wet FGD level of control to be a maximum of 98 percent not to go below 0.04 lb/MMBtu is also consistent with our determination in the 2011 Oklahoma FIP.[239] Issues that have been raised in the past concerning these conclusions are discussed further in Appendix A of the 2023 BART FIP TSD in the docket. Elsewhere in this notice and in the 2023 BART FIP TSD, we discuss the performance of the wet FGD on Fayette Units 1 and 2 as an example of units with emission rates consistent with our assumption of 0.04 lb/MMBtu with this control technology. We propose that this level of control for wet FGD is reasonable.

In evaluating the control effectiveness for SDA, the Control Cost Manual identifies the 12-month average emission rate for the top performing 50 percent of SDA systems as 0.06 lb/MMBtu. [240] As with our Oklahoma FIP, we have assumed an SDA level of control equal to 95 percent, unless that level of control would fall below an outlet SO_2 level of 0.06 lb/MMBtu, in

[237] EPA Air Pollution Control Cost Manual, Seventh Edition, April 2021 available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual. The EPA is currently in the process of updating the Control Cost Manual and this update will be the Seventh Edition. Although updates are not yet complete for all sections the EPA intends to update in the Seventh Edition, updated Section 5, Chapter 1, which is titled "Wet and Dry Scrubbers for Acid Gas Control," is now available and is part of the Seventh Edition of the Control Cost Manual.

[238] These observed overall SO_2 emission rates are likely attributable to a variety of factors including improvements in the design and operation of FGD systems and operational changes at some utilities from switching to lower sulfur coal and operating at less than full capacity. EPA Air Pollution Control Cost Manual, Seventh Edition, April 2021, Section 5, Chapter 1, p 1-12.

[239] As discussed previously in our TSD for that action, control efficiencies reasonably achievable by dry scrubbing and wet scrubbing were determined to be 95 percent and 98 percent respectively. 76 FR 81728, 81742 (2011); *Oklahoma v. EPA*, 723 F.3d 1201 (July 19, 2013), cert. denied (U.S. May 27, 2014). This level of control was also employed in our Texas-Oklahoma FIP. *See* 81 FR at 321.

[240] These observed overall SO_2 emission rates are likely attributable to a variety of factors including improvements in the design and operation of FGD systems and operational changes at some utilities from switching to lower sulfur coal and operating at less than full capacity. EPA Air Pollution Control Cost Manual, Seventh Edition, April 2021, Section 5, Chapter 1, p 1-12.

which case, we assume the percentage of control equal to 0.06 lb/MMBtu.[241] In that Oklahoma FIP, we finalized the same emission limit of 0.06 lb/MMBtu on a 30 BOD average for six coal-fired EGUs in Oklahoma. We justified those limits based on the same SDA technology, using a combination of industry publications and real-world monitoring data. Much of the information in support of our position that an emission limit of 0.06 lb/MMBtu on a 30 BOD average is within the demonstrated capabilities of SDA retrofits is summarized in our response to comments document for the Oklahoma FIP[242] and in our 2023 BART FIP TSD. We propose that this level of control for SDA is reasonable.

b. Evaluation of SO_2 Control Effectiveness for Coal-fired Units With Existing Scrubbers

Control Effectiveness of Upgrades to Existing Scrubbers

Of the units we are proposing to determine are subject to BART, Martin Lake Units 1, 2, and 3 are currently equipped with wet FGDs that are not high-performing. Based on information we received from the facility, which we obtained in response to our previous CAA Section 114(a) information collection request, we find that upgrades to the existing scrubbers should be considered as potential BART controls for these Martin Lake units. Because the company asserted a CBI claim for much of the information supplied to us, as provided in 40 C.F.R. § 2.203(b), we are limited in what information we can include in this section. The following summary is based on information not claimed as CBI.

- The absorber system could be upgraded to perform at an SO_2 removal efficiency of at least 95 percent using proven equipment and techniques.

[241] *See* 76 FR 81728 (December 28, 2011).
[242] 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.

- 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 percent removal efficiency.
- Additional modifications necessary to eliminate the bypass could be performed using proven equipment and techniques.
- The additional SO_2 emission reductions resulting from the scrubber upgrade would be substantial.

Given that we lack Continuous Emissions Monitoring Systems (CEMS) data for the inlet of the scrubbers and only have CEMS data for the outlet of the scrubbers, we calculated the current removal efficiency of each scrubber by utilizing the reported sulfur content and tonnages of the fuels burned and reported to EIA[243] and the monitored SO_2 scrubber outlet emissions reported to the EPA.[244] Our approach for estimating the current removal efficiency of the existing scrubbers is discussed in greater detail in our 2023 BART FIP TSD in the docket. Based on emissions rate data and reported sulfur content and tonnages of the fuels burned in 2016 – 2020, we have estimated that the current removal efficiency of the existing scrubbers at the Martin Lake units is approximately 64 percent at Unit 1, 66 percent at Unit 2, and 64 percent at Unit 3.[245] We find that an assumption that upgrades to the existing scrubbers can increase their control efficiency to 95 percent at Martin Lake Units 1, 2, and 3 is reasonable. This is below the upper end of what an upgraded wet SO_2 scrubber can achieve, which is 98–99 percent, as we have noted in the 2023 BART FIP TSD in the docket. We believe that a 95 percent control assumption provides an adequate margin of error, such that the Martin Lake units would be able to comfortably achieve this removal efficiency. Based on the reported sulfur content and

[243] EIA Form 923. Available at https://www.eia.gov/electricity/data/eia923/.
[244] EPA Air Markets and Programs Data. Available at https://campd.epa.gov/.
[245] *See* “Coal vs CEM data 2016-2020_ML.xlsx,” tab “charts,” cell H12. This Excel spreadsheet is located in the docket associated with this proposed rule.

tonnages of the fuels burned in 2016 – 2020, 95 percent control would equate to an emission rate of 0.08 lb/MMBtu for each unit.

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

The BART Guidelines offer the following with regard to how Step 4 should be conducted:[246]

> 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 there are usually no appreciable differences in these factors from unit to unit.[247] 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).[248] We proceed in our SO_2 cost analyses by examining the current SO_2 emissions and the level of SO_2 control, if any, for each of the coal-fired units listed in Table 7.[249]

---

[246] 70 FR at 39166.
[247] 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.
[248] EPA Air Pollution Control Cost Manual, Seventh Edition, April 2021 available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual. The EPA is currently in the process of updating the Control Cost Manual and this update will be the Seventh Edition. Although updates are not yet complete for all sections the EPA intends to update in the Seventh Edition, updated Section 5, Chapter 1, which is titled “Wet and Dry Scrubbers for Acid Gas Control,” is now available and is part of the Seventh Edition of the Control Cost Manual.
[249] W. A. Parish WAP4 is the only gas-fired unit we determined to be subject to BART. As we discussed in Section VII.B.1.c, gas-fired EGUs have inherently low SO_2 emissions and there are no known SO_2 controls that can be evaluated. Therefore, our cost analysis does not include WAP4.

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

As we discuss in Section VII.B.2. and in our 2023 BART FIP TSD associated with this notice, we evaluated each unit at the assumed maximum SO_2 performance levels, considering the type of SO_2 control device. For DSI, in addition to evaluating each unit at the assumed maximum achievable level of SO_2 control, we also evaluated each unit at 50 percent control efficiency. In Table 9 we present a summary of our DSI, SDA, and wet FGD cost analysis.[250]

Table 9. Summary of DSI, SDA, and Wet FGD Cost Analysis

Facility	Unit	Control	Control level (%)	SO_2 reduction (tpy)	Annualized Cost	Cost Effectiveness ($/ton)[1]	Incremental Cost-Effectiveness ($/ton)[2,3]
Coleto Creek	1	DSI	50	6,680	$15,016,712	$2,249	
		DSI	90	12,024	$29,320,229	$2,439	$2,677
		SDA	91	12,035	$32,400,831	$2,692	$3,246
		Wet FGD	94	12,448	$36,238,608	$2,911	$9,292
Harrington	061B	DSI	50	1,892	$7,075,817	$3,740	
		DSI	80	3,027	$11,596,018	$3,830	$3,983
		SDA	89	3,327	$21,967,236	$6,603	$10,377
	062B	DSI	50	2,703	$7,408,200	$2,742	
		DSI	89	4,794	$13,104,954	$2,734	$2,724
		SDA	89	4,812	$23,369,564	$4,857	$7,568
Welsh	1	DSI	50	3,959	$10,952,162	$2,766	
		DSI	87	6,885	$18,562,875	$2,696	$2,601
		SDA	87	6,878	$30,056,814	$4,370	$6,545
		Wet FGD	91	7,219	$32,464,043	$4,497	$7,059
		DSI	50	6,689	$15,125,672	$2,262	

250 In this table, the annualized cost is the sum of the annualized capital cost and the annualized operational cost. See our TSD for more information on how these costs were calculated.

W. A. Parish	WAP 5	DSI	90	12,039	$29,457,805	$2,447	$2,679
		SDA	91	12,139	$36,957,568	$3,044	$4,006
		Wet FGD	94	12,560	$38,607,330	$3,074	$3,919
	WAP 6	DSI	50	6,902	$15,489,974	$2,244	
		DSI	90	12,423	$30,246,942	$2,435	$2,673
		SDA	91	12,475	$33,070,310	$2,651	$3,155
		Wet FGD	94	12,908	$35,073,781	$2,717	$4,627

[1] We evaluated DSI both at the assumed maximum DSI performance levels of 80/90 percent specified in the April 2017 IPM DSI documentation and at 50 percent control efficiency. However, we note there is uncertainty that the units we are evaluating for DSI are actually capable of achieving the assumed maximum DSI performance levels specified in the April 2017 IPM DSI documentation and there is also potential uncertainty in the DSI cost estimates at these high DSI performance levels.
[2] The incremental cost effectiveness calculation compares the costs and performance level of a control option to those of the next most stringent option, as shown in the following formula (with respect to cost per emissions reduction): Incremental Cost Effectiveness (dollars per incremental ton removed) = (Total annualized costs of control option) - (Total annualized costs of next control option) ÷ (Control option annual emissions) - (Next control option annual emissions). See Section IV.D.4.e of Appendix Y to Part 51 – Guidelines for BART Determinations Under the Regional Haze Rule.
[3] We calculated the incremental cost-effectiveness of SDA by comparing it to DSI at 50 percent control efficiency rather than to DSI at 80/87/89/90 percent control efficiency. We took this approach given the following considerations: (1) the control efficiencies of SDA and DSI at the assumed maximum DSI performance level for units with fabric filters specified in the April 2017 IPM DSI documentation are assumed to be identical; (2) there is uncertainty that the units we are evaluating for DSI are actually capable of achieving the assumed maximum DSI performance levels specified in the April 2017 IPM DSI documentation; and (3) there is potential uncertainty in the cost estimates for DSI at these high DSI performance levels, as discussed later in this subsection.

For the coal units without any SO_2 control, we calculated the cost of installing DSI, an SDA scrubber, and a wet FGD scrubber. In order to estimate the costs for SDA scrubbers and wet FGD scrubbers, we used the "Air Pollution Control Cost Estimation Spreadsheet For Wet and Dry Scrubbers for Acid Gas Control," which is an Excel-based tool that can be used to estimate the costs for installing and operating scrubbers for reducing sulfur dioxide and acidic gas emissions from fossil fuel-fired combustion units and other industrial sources of acid gases.[251] The methodologies for wet FGD scrubbers and SDA scrubbers are based on those from

[251] Air Pollution Control Cost Estimation Spreadsheet For Wet and Dry Scrubbers for Acid Gas Control, U.S. Environmental Protection Agency, Air Economics Group, Health and Environmental Impacts Division, Office of Air Quality Planning and Standards (January 2023), downloaded from https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

version 6 of our IPM model.[252] The size and costs of a wet FGD scrubber and SDA scrubber are based primarily on the size of the combustion unit and the sulfur content of the coal burned. The wet FGD scrubber methodology includes cost algorithms for capital and operating cost for wastewater treatment consisting of chemical pretreatment, low hydraulic residence time biological reduction, and ultrafiltration to treat wastewater generated by the wet FGD system. The calculation methodologies used in the "Air Pollution Control Cost Estimation Spreadsheet For Wet and Dry Scrubbers for Acid Gas Control," are those presented in the U.S. EPA's Air Pollution Control Cost Manual.

The cost algorithm used in the "Air Pollution Control Cost Estimation Spreadsheet For Wet and Dry Scrubbers for Acid Gas Control" calculates the Total Capital Investment, Direct Annual Cost, and Indirect Annual Cost. The Total Capital Investment for wet FGD is a function of the absorber island capital costs, reagent preparation equipment costs, waste handling equipment costs, balance of plant costs, and wastewater treatment facility costs. For SDA, the Total Capital Investment is a function of the absorber island capital costs that include both an absorber and a baghouse, reagent preparation and waste recycling/handling costs, and balance of plant costs. The Direct Annual Costs consist of annual maintenance cost, annual operator cost, annual reagent cost, annual make-up water cost, annual waste disposal cost, and annual auxiliary power cost. Additionally, the Direct Annual Costs for wet FGD also include annual wastewater treatment cost and the replacement cost of a mercury monitor (replaced once every 6 years). The Indirect Annual Cost consists of administrative charges and capital recovery costs.

[252] *See* Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, dated September 2021. Documentation for v.6 downloaded from https://www.epa.gov/power-sector-modeling/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference.

To estimate the costs for DSI, we relied on the EPA's April 2017 IPM DSI documentation[253] and the 2019 version of the EPA's RCA tool, which employs version 6 of our IPM model.[254] The cost algorithm used in the RCA tool calculates the Total Project Cost (TPC), Fixed Operating and Maintenance (Fixed O&M) costs, and Variable Operating and Maintenance (Variable O&M) costs. As we discuss in Section VII.B.2.a., for DSI systems using a fabric filter for particulate control and operating at high SO_2 removal efficiency, it is expected that filter bag wear would occur more rapidly and that filter bags would need to be replaced more frequently due to the increased dry waste product. The frequent need to clean and replace the filter bags may become impractical and additional fabric filter compartments may need to be added to handle the high loading that occurs at high SO_2 removal efficiencies. This impacts the cost and leads to some uncertainty in our cost estimates for DSI at high SO_2 removal efficiencies given that we do not have site-specific information and performance testing to determine how frequently filter bags would need to be replaced or whether additional fabric filter compartments are necessary. Similarly, DSI systems with an ESP for particulate control may not be capable of handling the higher loadings at high SO_2 removal efficiencies and would require consideration of additional costs for a new ESP or fabric filter to handle the load at these high sorbent injection rates. This impacts the cost and leads to some uncertainty in our cost estimates for DSI with an existing ESP (for Harrington Unit 061B) given that our cost estimates do not reflect the cost of a

[253] *See* Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, dated September 2021. Documentation for v.6 downloaded from https://www.epa.gov/power-sector-modeling/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference.
IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology, Final April 2017, Project 13527-001, Eastern Research Group, Inc., Prepared by Sargent & Lundy. Documentation for v.6: Chapter 5: Emission Control Technologies, Attachment 5-5: DSI Cost Methodology, downloaded from https://www.epa.gov/sites/default/files/2018-05/documents/attachment_5-5_dsi_cost_development_methodology.pdf.

[254] Retrofit Cost Analyzer, rev: 06-04-2019, downloaded from https://www.epa.gov/power-sector-modeling/retrofit-cost-analyzer.

new ESP or fabric filter even though we do not know with certainty whether the existing ESP can handle the high sorbent injection rates needed at high SO_2 removal efficiency.

As we discuss in Section VII.B.2.a, we expect that by the time this proposal is published in the Federal Register, or shortly thereafter, the EPA will have issued an updated version of the IPM DSI documentation and an updated version of the RCA tool for calculating the cost of DSI. We will include these documents in the docket once they are finalized and made publicly available. As these updated documents were not available at the time we developed our cost analysis, we did not rely on this information in our DSI cost analysis presented in this proposal. In general, the updated IPM DSI documentation and updated RCA tool for DSI suggest that DSI could potentially achieve higher SO_2 control efficiencies and at a similar cost per SO_2 tons removed. Absent site-specific information from the facilities that we evaluated for DSI, we believe that our concerns regarding the uncertainty of whether these units are actually capable of achieving the assumed maximum DSI performance levels and the uncertainty in the cost estimates for DSI at high SO_2 removal efficiencies would still exist even if we were to rely on the updated versions of the IPM DSI documentation and the RCA tool. However, we invite comments on the range and maximum control efficiency that can be achieved with DSI at the evaluated units and estimates of the range of associated costs. We are especially interested in any site-specific DSI testing for the units we evaluated to determine the range and maximum control efficiency that can be achieved at those units and any other unit-specific information that would help provide better insight into the unit-specific DSI costs. Any data to support the control efficiency range, maximum control efficiency, and cost of DSI for a particular unit should be submitted along with those comments. We will further consider DSI site-specific information provided to us during the public comment period in our final decision and potentially re-evaluate DSI for those particular units.

The cost models used in IPM version 6 were based on 2016 dollars. Thus, in performing the cost calculations[255] for each unit listed in Table 9 we have escalated the costs to 2020 dollars. For DSI, we accomplished this escalation using the annual Chemical Engineering Plant Cost Indices (CEPCI). For the SDA and wet FGD scrubbers, the "Air Pollution Control Cost Estimation Spreadsheet For Wet and Dry Scrubbers for Acid Gas Control" allows the user to enter a different dollar-year for costs and the corresponding cost index if a different dollar-year is desired. Using this capability, we entered the 2020 CEPCI index into the spreadsheet to estimate the cost of wet FGD scrubbers and SDA scrubbers in 2020 dollars. For a more detailed discussion of the inputs and cost calculations, see our 2023 BART FIP TSD in the docket.

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

In our 2023 BART FIP TSD associated with this proposed rulemaking, we analyze those units listed in Table 7 of this notice that have 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; and Fayette Units 1 and 2 are currently equipped with wet FGDs. As discussed in Section VII.B.1.b, because the Fayette units are already performing at the maximum level of control we considered for wet FGD, we will not evaluate any additional scrubber upgrades for these two units.

Martin Lake was the highest emitting EGU facility for SO_2 in the United States for the past four years (2018-2021). On an individual unit basis, Martin Lake Units 1, 2, and 3 were the top three emitting units in the country in 2018 and among the top four emitting units in 2019 and

[255] The cost calculation spreadsheets can be found in the docket for this action under the heading "Cost Calculations".

2021.[256] In general, given the very large emissions, potential for large emission reductions, and the lower costs associated with upgrading existing controls compared to a new scrubber retrofit, it is reasonable to expect scrubber upgrades at Martin Lake to be very cost-effective in terms of cost per ton removed. A review of emissions data for these units shows significant variability and demonstrates the ability of these units to be operated with higher removal efficiency to maintain lower emission levels for periods of time depending on the mixture of coals, the operation of the scrubbers, and the amount of scrubber bypass. For example, in 2016, the annual average emission rate for the three units ranged from 0.3 to 0.43 lb/MMBtu, but in 2020, the annual average emission rate ranged from 0.55 to 0.73 lb/MMBtu.[257] At the same time, the amount of higher sulfur lignite burned in 2016 was higher than in 2020[258] (61 to 71 percent of heat input came from lignite in 2016 for the three units compared to 14 to 32 percent in 2020), meaning that the scrubbers and amount bypassed were operated in a manner that achieved a significantly higher overall removal efficiency in 2016 than in 2020. Table 10 summarizes the annual emission rate and the estimated annual scrubber removal efficiency. Given the variability in demonstrated scrubber efficiency, higher removal efficiency can be and has been achieved with optimized operation, reduced bypass, and increased reagent use with the current configuration of the scrubbers. As discussed earlier in this section, additional remaining cost-effective physical modifications to the scrubbers can further improve scrubber removal efficiency. This further supports our assessment that increased scrubber efficiency is cost-effective.

[256] In 2019 and 2021, a unit at the Gavin Facility in Ohio was the third highest emitting unit in the country. In 2020, the three Martin Lake units fell within the top 6 units. *See* "Largest_units_SO2_annual emissions 2016-2021.xlsx" available in the docket for this action.
[257] *See* "Largest_units_SO2_annual emissions 2016-2021.xlsx" available in the docket for this action.
[258] *See* "Coal vs CEM data 2016-2020_ML.xlsx" available in the docket for this action.

Table 10. Martin Lake Annual Emission Rate and Estimated Annual Scrubber Removal Efficiency

Martin Lake	Annual emission rate (lb/MMBtu)		Estimated overall removal efficiency	
	2016	2020	2016	2020
Unit 1	0.42	0.73	78.2%	52.8%
Unit 2	0.30	0.60	84.5%	62.8%
Unit 3	0.43	0.55	78.0%	62.8%

The cost of scrubber upgrades at coal-fired power plants has been evaluated in many other instances in both the context of BART and reasonable progress for both the first and second planning periods for regional haze. Based on what we have seen in other regional haze actions, upgrading an underperforming SO_2 scrubber is generally very cost-effective.[259] In our TSD, we provide further discussion of other regional haze actions where scrubber upgrades have been found to be very cost-effective.

In the Texas Regional Haze SIP for the Second Planning Period recently submitted to us by TCEQ, the State evaluated Martin Lake Units 1, 2, and 3 for controls under the reasonable progress requirements for the regional haze second planning period.[260] Specifically, TCEQ evaluated scrubber upgrades for the Martin Lake units, the same SO_2 control type we have evaluated for those units in this proposal. In that SIP submittal, TCEQ took an approach in its

[259] *See* for instance, the North Dakota Regional Haze SIP: scrubber upgrades for the Milton R. Young Station Unit 2 were evaluated under BART and were found to cost $522/ton and scrubber upgrades with coal drying for the Coal Creek Station Units 1 and 2 were evaluated under BART and found to cost $555/ton at each unit. See the EPA's final action approving the SO_2 BART determinations for the Coal Creek Station Units 1 and 2 and for the Milton R. Young Station Unit 2 at 77 FR 20894 (April 6, 2012). See also the Wyoming Regional Haze SIP: scrubber upgrades for Wyodak Unit 1 were evaluated to address the regional haze rule requirements under 40 CFR 51.309 and found to cost $1,167/ton. The EPA approved this portion of the Wyoming Regional Haze SIP at 77 FR 73926 (December 12, 2012).

[260] The Texas Regional Haze SIP for the Second Planning Period was submitted to the EPA by TCEQ on July 20, 2021. A copy of this submission is available at https://www.tceq.texas.gov/airquality/sip/bart/haze_sip.html and in the docket for this action.

cost analysis of scrubber upgrades different from ours in this proposal and they did not rely on cost information from the facility. As they did not rely on cost information claimed to be CBI by the facility, TCEQ was able to present estimated cost-effectiveness numbers for scrubber upgrades for the Martin Lake units in their SIP submittal. TCEQ estimated the cost-effectiveness of scrubber upgrades at Martin Lake to be $907/ton for Unit 1; $1,040/ton for Unit 2; and $891/ton for Unit 3. Since we have not completed our review of the Texas Regional Haze SIP for the Second Planning Period and have not yet proposed action on it, we are not at this time taking a position on the approvability or appropriateness of TCEQ's cost analyses and determinations in the Texas Regional Haze SIP for the Second Planning Period. We merely present TCEQ's cost-effectiveness estimates here to illustrate that they are comparable to our own cost-effectiveness estimates in this notice.

In our cost analysis of scrubber upgrades for the Martin Lake units, we are using information we received from the facility in response to our previous CAA Section 114(a) information collection request. We are limited in what information we can include in this section because the facility claimed this information as CBI. We can disclose that we previously used this information claimed as CBI by the facility to calculate the total annualized costs for the Martin Lake units in our 2016 Texas-Oklahoma FIP.[261] We have escalated those total annualized costs to 2020 dollars and are using this to estimate the cost-effectiveness of scrubber upgrades at these units. As we discuss in Section VII.B.2.b, we believe that modifications necessary to eliminate the bypass could be performed using proven equipment and techniques to increase the control efficiency of the scrubbers to 95 percent and substantially reduce SO_2 emissions at these units. Our estimates of the baseline emissions and the annual SO_2 emissions reductions

[261] *See generally*, 81 FR 296 (Jan 5, 2016).

anticipated from upgrading the scrubbers at Martin Lake Units 1, 2, and 3 are presented in Table 11. Using the anticipated annual SO_2 emissions reductions presented in Table 11, we have estimated the cost-effectiveness of scrubber upgrades at these units. Because those calculations depended on cost information claimed by the facility as CBI, we cannot present them here except to note that for each unit, the cost-effectiveness was less than $1,200/ton.

Table 11. Martin Lake Updated Baseline Emissions and SO_2 Emissions Reductions Due to Scrubber Upgrades

Unit	**2016-2020 Avg Annual Emissions (tons)**	**SO_2 Emissions at 95% Control (tons)**	**Annual SO_2 Emissions Reduction Due to Scrubber Upgrade (tons)**	**SO_2 Emission Rate at 95% Control (lb/MMBtu)**
Martin Lake 1	14,885	2,047	12,838	0.08
Martin Lake 2	11,909	1,769	10,140	0.08
Martin Lake 3	14,121	1,941	12,180	0.08
Total SO_2 Removed			35,158	

We recognize that the information we used in our cost analysis on scrubber upgrades was provided by the facility several years ago and that our escalation of the total annualized costs from 2013 to 2020 dollars introduces some level of uncertainty in our cost estimates. We acknowledge that it is reasonable to assume that the cost information we received from the facility may have changed in the interim, due to changes in the costs of various materials and services, as well as possible recent upgrades to the scrubbers that may have already been implemented at these units that would no longer need to be considered in our cost analysis. However, based on the information presented in this subsection, we find that the cost of scrubber upgrades at the Martin Lake units is so low in terms of dollars per ton reduced such that even if we had updated cost information, we expect that scrubber upgrades would continue to be very cost-effective. Accordingly, we would still propose to require upgrades to these SO_2 scrubbers in light of the significant visibility benefits, as discussed later in our weighing of the factors in Section VIII. Nevertheless, we invite comment on any additional analysis on the cost of scrubber upgrades at the Martin Lake units that may have been conducted in the interim period following Luminant's response to our request for cost information. We also invite comments regarding documentation on any upgrades or optimization that may have been made to the scrubbers at the Martin Lake units in the interim period. Finally, we invite comment on whether a lower emission limit of 0.04 lb/MMBtu should be required that would be consistent with 95 percent control efficiency and the burning of only subbituminous coal.[262]

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 lb/MMBtu for years at a time.[263] As we discuss in Section VII.B.2, we evaluate BART demonstrating that retrofit wet FGDs should be evaluated at 98 percent control not to go below 0.04 lb/MMBtu. Because the Fayette units are already performing below this level, we propose that no scrubber upgrades are necessary and there are no additional costs associated with maintaining the current levels of operation.

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

i. Energy and Non-air Quality Environmental Impacts

[262] In the Matter of an Agreed order Concerning Luminant Generation Company, LLC, Martin Lake Steam Electric Station, Docket No. 2021-0508-MIS includes a requirement to burn only subbituminous coal.
[263] *See* our 2023 BART FIP TSD for graphs of this data.

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."[264] The key part of this analysis is the energy requirements of the "control technology." As such, this part of the analysis is focused on considering the various energy impacts of the control technologies identified earlier in the BART analysis as technologically feasible and determining whether there are energy penalties or benefits associated that may factor into the overall decision to select a certain control technology over another. Such considerations would include extra fuel or electricity to power a control device or the availability of potentially scarce fuels.[265] As discussed in our 2023 BART FIP TSD, 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 through the inclusion of related costs of electricity to operate the controls.

Neither the CAA nor the BART Guidelines specifically require the examination of grid reliability considerations because utilities may shut down or retire a unit rather than comply with a more stringent emission limit or limits. However, the Guidelines recognize there may be cases where the installation of controls, even when cost-effective, would "affect the viability of continued plant operations."[266] Under the Guidelines, where there are "unusual circumstances," we are permitted to take into consideration "the conditions of the plant and the economic effects

[264] 70 FR 39103, 39168 (July 6, 2005), [40 CFR Part 51, App. Y.].
[265] 70 FR at 39168-69.
[266] 70 FR 39103, 39171 (July 6, 2005), [40 CFR Part 51, App. Y].

of requiring the use of a control technology."[267] 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."[268] 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.[269] As suggested by the Guidelines, the information necessary to inform our judgment with respect to the viability of continued operations for a source would likely entail source-specific information on "product prices, the market share, and the profitability of the source." 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."[270] 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 cost effective. The emission limits that we propose for these sources are based on conventional, proven, at-the-source pollution control technology that is in place across a vast portion of the existing EGU fleet in the United States.[271] In general these pollution controls are cost-effective and can be implemented while the EGU continues in large part to operate as it had before.

[267] *Id.*
[268] 70 FR at 39171.
[269] The FOR FURTHER INFORMATION 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.
[270] 70 FR at 39171.
[271] *See* EIA Reported Desulfurization Systems in 2020 data in Table 8 of this notice showing the hundreds of scrubber installations that have been performed on similar EGUs.

Should any of the units faced with a final BART emission limit choose instead to explore retirement, such a decision would presumably be made on the basis of a determination that the retirement of the unit would be the more economical choice, taking into account any and all regulatory requirements impacting the source and market conditions. Further, the relevant grid operator would follow their planning requirements to ensure that sufficient reserve capacity is available.

We have also reviewed available information regarding the grids operating in Texas to provide data on these generation units and reserve capacity. The Welsh and Harrington facilities operate as part of the Southwest Power Pool (SPP).[272] The owners of these facilities have announced plans to convert to natural gas in the near future so it is unlikely that these sources would now choose to shut down as a result of the proposed BART requirements, which could be met by burning natural gas instead of coal.[273] The Electric Reliability Council of Texas (ERCOT) operates Texas's electrical grid which represents 90 percent of the state's electric load. Coleto Creek, Fayette, Martin Lake, and W. A. Parish facilities produce power for the ERCOT grid. As discussed elsewhere, we are not proposing to require additional reductions from the Fayette units due to their high efficiency scrubbers. For that reason, we do not anticipate any impact to operations of this source. Further, the owners of Coleto Creek already have announced their intentions to shut down the unit in 2027,[274] citing costs imposed by federal regulations for coal ash disposal and wastewater treatment, and market pressures. Therefore, we focus the remainder of this section on the Martin Lake and W. A. Parish BART units.

---

[272] SPP oversees the bulk electric grid and wholesale power market in the central United States for utilities and transmission companies in 17 states.
[273] *See* Section VII.B.3.c.ii for more information regarding Harrington's conversion to natural gas.
[274] Rosenberg, Mike. "Coleto Creek Power Plant shutting down by 2027." Victoria Advocate, December 1, 2020, https://www.victoriaadvocate.com/counties/goliad/coleto-creek-power-plant-shutting-down-by-2027/article_261596c8-342b-11eb-92e8-0f9c2d927a2b.html. Last Accessed February 1, 2023.

One way to evaluate potential changes to the grid is to examine forecasted peak demand and generation capacity for summer and winter. These five coal-fired units represent 3,737 MW of summer capacity.[275] ERCOT's November 2022 Report on the Capacity, Demand and Reserves[276] estimates that 2023 operational generation capacity for summer peak demand will be 92,792 MW with additional planned resource capacity expected for the 2023 summer peak demand of 4,400 MW. This includes 1,254 MW of summer-rated gas-fired resources, and the remainder in additional wind and solar resources becoming available by next summer. Summer peak demand is estimated to be 80,218 MW for 2023, resulting in an estimated reserve margin of 22.2 percent for 2023, with capacity outpacing demand by approximately 18,000 MW. That reserve margin is projected to increase to 39.9 percent for summer 2024, as planned generation increases to almost 21,400 MW, largely reflecting solar capacity additions for 2024 and increasing total estimated capacity to 115,000 MW. The current minimum target reserve margin established by ERCOT is 13.75 percent. Projections through 2027 include additional planned generation for a total estimated capacity of 121,000 MW and an estimated reserve margin of 40.1 percent in 2027. Projections for 2028 through 2032 hold generation capacity at 2027 levels (no additional planned capacity) but continue to project increased demand each year resulting in a decreasing reserve margin each year with 2032 estimated at 36.3 percent.

ERCOT's November 2022 Report on the Capacity, Demand and Reserves[277] estimates that 2023/2024 operational generation capacity for winter peak demand will be 90,599 MW with

---

[275] Report on the Capacity, Demand, and Reserves (CDR) in the ERCOT Region, 2023-2032. November 29, 2022. Available at https://www.ercot.com/files/docs/2022/11/29/CapacityDemandandReservesReport_Nov2022.pdf and in the docket for this action.
[276] Report on the Capacity, Demand, and Reserves (CDR) in the ERCOT Region, 2023-2032. November 29, 2022. Available at https://www.ercot.com/files/docs/2022/11/29/CapacityDemandandReservesReport_Nov2022.pdf and in the docket for this action.
[277] Report on the Capacity, Demand, and Reserves (CDR) in the ERCOT Region, 2023-2032. November 29, 2022. Available at https://www.ercot.com/files/docs/2022/11/29/CapacityDemandandReservesReport_Nov2022.pdf and in the docket for this action.

additional planned resource capacity expected for the 2023 summer peak demand of 2,893 MW. This includes 1,323 MW of winter-rated gas-fired resources, and the remainder in additional wind and solar resources becoming available by next winter. Winter peak demand is estimated to be 66,645 MW for 2023/2024, resulting in an estimated reserve margin of 35.9 percent for Winter 2023/2024. That reserve margin is projected to increase to 36.2 percent for winter 2024/2025, and then decrease to 28.7 percent for winter 2027/2028 as projected peak demand increases.

The SO_2 BART emission limits for these EGUs are proposed to take effect no later than five years from the effective date of a final rule (Martin Lake's scrubber upgrades would be required within three years).[278] Thus, even if all five of these units chose to retire instead of complying with the BART emission limits, the removal of 3,737 MW of summer capacity (3,782 MW winter capacity) would decrease the estimated summer reserve margin to 35.8 percent in 2027 (estimated winter 2027/2028 reserve margin decreases to 23.6 percent). Even if we also account for the additional 655 MW loss of generation from Coleto Creek in 2027, the summer reserve margin would be estimated to be 35.1 percent with estimated summer generating capacity of 116,706 MW, about 30,000 MW more than the projected summer peak demand. The winter 2027/2028 reserve margin would be 22.7 percent, with generating capacity about 16,500 MW higher than peak demand when including the loss of Coleto Creek generation. Further, this level of reserve generating capacity is already projected to be available without considering whether the owners or operators of the affected EGUs would continue to invest and pursue additional replacement generation projects. Based on this analysis, there will be more than

[278] *See* 76 FR 81729, 81758 (December 28, 2011) and 81 FR 66332, 66416 (September 27, 2016), where we promulgated regional haze FIPs for Oklahoma and Arkansas, respectively. These FIPs required BART SO_2 emission limits on coal-fired EGUs based on new scrubber retrofits with a compliance date of no later than five years from the effective date of the final rule.

sufficient existing and planned capacity in the ERCOT grid to provide for substitute generation and reserve capacity by the time the BART emission limits would take effect to meet the projected demand.

To further evaluate the potential changes to the grid due to retirements, we also examined ERCOT's December 2017 Report on the Capacity, Demand and Reserves,[279] the first report issued after the announced retirement of 4,273 MW of generating capacity from the Luminant facilities (Monticello, Big Brown, and Sandow) in early 2018. Due to the retirements, the reserve margin was projected to decrease to 9.3 percent for summer 2018 and 9.0 percent in summer 2022. In response to requests from Luminant to retire these units, ERCOT issued determinations that these resources were not required to support ERCOT transmission system reliability in early 2018 and allowed to permanently retire. Additional gas, solar and wind resources have come online since that time to increase the generation capacity and provide for a much larger reserve margin. And again, this rule, if finalized, only establishes an emission limit for each EGU that could be met with proven, conventional, at the source control technologies already in use across a broad swath of the U.S. EGU fleet; thus retirements, if they should occur, are at the discretion of the sources and subject to the reliability authority and planning requirements that would be overseen by the grid operator, ERCOT.

Regarding the analysis of non-air quality environmental impacts, the BART Guidelines advise[280]:

> 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

[279] Report on the Capacity, Demand, and Reserves (CDR) in the ERCOT Region, 2018-2027. December 18, 2017. Available at https://www.ercot.com/files/docs/2018/01/03/CapacityDemandandReserveReport-Dec2017.pdf and in the docket for this action.
[280] 70 FR at 39169 (July 6, 2005), [40 CFR Part 51, App. Y.].

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. As discussed in our cost analyses for DSI and scrubbers, our cost model includes estimated waste disposal costs in the variable operating costs. With DSI, when sodium-based sorbents such as trona are captured in the same particulate control device as the fly ash, the resulting waste must be landfilled.[281] We are aware that some facilities may sell their fly ash, and that the addition of trona may render that fly ash unsellable. We included the fly ash disposal costs in the variable operation and maintenance costs for DSI in all cases, but our cost analysis did not account for any potential lost revenue resulting from being unable to sell the fly ash. We invite comments on the assumptions we have made regarding fly ash disposal costs and on any unforeseen waste disposal costs associated with DSI when using trona or sodium bicarbonate.

[281] IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology, Final April 2017, Project 13527-001, Eastern Research Group, Inc., Prepared by Sargent & Lundy, p.6.

Regarding water related impacts, we recognize that wet FGD requires additional amounts of water as compared to SDA and DSI. Furthermore, based on recent Effluent Limitation Guidelines (ELG), it is expected that all future wet FGD installations will require the facility to incorporate a wastewater treatment facility.[282] While this cost is factored into our cost analysis, it also highlights water quality concerns associated with the waste stream for wet FGD as compared to the installation of dry scrubbers and DSI. Additionally, we are aware of water availability concerns in the area surrounding the Harrington facility. As such, the Harrington facility has instituted a water recycling program and obtains some of its water from the City of Amarillo.[283] Because of the increased water required for wet FGD as compared to dry scrubbers and DSI, we limit our SO_2 control analysis for Harrington to DSI and dry scrubbers. For the other facilities where we consider wet FGD as a potential control option, we weigh the additional water usage and wastewater treatment requirements associated with wet FGD in comparison to other control options.

ii. Remaining Useful Life

Regarding the remaining useful life, the BART Guidelines advise:[284]

> 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

[282] IPM Model – Updates to Cost and Performance for APC Technologies, Wet FGD Cost Development Methodology, Final January 2017, Project 13527-001, Eastern Research Group, Inc., Prepared by Sargent & Lundy, p. 1.
[283] https://www.powermag.com/xcel-energys-harrington-generating-station-earns-powder-river-basin-coal-users-group-award/.
[284] 70 FR 39103, 39169, [40 CFR Part 51, App. Y].

for amortizing costs, you should use this shorter time period in your cost calculations.

We have no reason to conclude that the remaining useful life of any SO_2 control options we are evaluating would be any less than the thirty years recommended by the Control Cost Manual.[285] As we stated in our Oklahoma FIP,[286] the scrubber vendors indicated 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 are still in operation, such as the scrubbers at Martin Lake. These scrubbers were installed in the early 1970s, and, while they may be inefficient for a modern scrubber, they are still operational.

Some of the facilities we have analyzed for BART in this action have announced plans to retire or refuel to natural gas within the next several years.[287] For example, we are aware that Xcel Energy has signed an Administrative Order with TCEQ to refuel Harrington Units 061B and 062B to natural gas by January 1, 2025.[288] We discuss this change in future operating conditions in our weighing of the factors. However, the BART Guidelines state that in situations where a future operating parameter will differ from past or current practices, and if such future

---

[285] EPA Air Pollution Control Cost Manual, Seventh Edition, April 2021, Section 5 "SO_2 and Acid Gas Controls," Chapter 1 "Wet and Dry Scrubbers for Acid Gas Control," see Section 1.1.6, p. 1-8, available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual.

[286] 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.

[287] We received a November 21, 2016, letter from the source owner regarding W. A. Parish Units WAP5 & WAP6. The letter available in 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. We are not aware of any more recent commitments to change operations at these units that would impact our BART analysis at this time. Rosenberg, Mike. "Coleto Creek Power Plant shutting down by 2027." Victoria Advocate, December 1, 2020, https://www.victoriaadvocate.com/counties/goliad/coleto-creek-power-plant-shutting-down-by-2027/article_261596c8-342b-11eb-92e8-0f9c2d927a2b.html. Last Accessed February 1, 2023. "SWEPCO to End Coal Operations at Two Plants, Upgrade a Third"." Southwestern Electric Power Co.'s News Release, November 5, 2020, https://www.swepco.com/company/news/view?releaseID=5847. Last Accessed February 2, 2023.

[288] In the Matter of an Agreed Order Concerning Southwestern Public Service Company, dba Xcel Energy, Harrington Station Power Plant, TCEQ Docket No. 2020-0982-MIS (Adopted Oct. 21, 2020). A copy of the Order is available in the docket for this action.

operating parameters will have a deciding effect in the BART determination, then the future operating parameters need to be made federally enforceable and permanent to consider them in the BART determination.[289]

If a facility owner were to enter into a federally enforceable commitment to shut down or refuel by a date certain, that date would be used to revise the remaining useful life and the annualized costs weighed in making the BART determination. Whether that adjustment in analysis would ultimately alter our final BART determinations from this proposal would depend on the outcome of an updated BART analysis with the inclusion of the shutdown or refuel date. Should an owner decide to shut down or refuel a unit before the compliance date set out for the proposed BART controls, the shutdown or refueling to natural gas would also achieve the required SO_2 emission limits.

4. Step 5: Evaluate Visibility Impacts

The 2023 BART Modeling TSD describes in detail the modeling runs we conducted, our methodology and selection of emission rates, modeling results, and final modeling analyses that we used to evaluate the benefits of the proposed controls and their associated emission decreases on visibility impairment values. In this section, we present a summary of our analyses and our proposed findings regarding the estimated visibility benefits of emission reductions based on the CALPUFF and/or CAMx modeling results. For those sources that are within 450 km of a Class I area (Martin Lake, Harrington, and Welsh), we utilized both CALPUFF and CAMx modeling results to assess the visibility benefits of potential controls. For the remaining coal-fired sources (Coleto Creek, Fayette, and W. A. Parish), only CAMx modeling was utilized, as these sources are located at greater distances from the nearest Class I areas than typically modeled with the

[289] 70 FR at 39167.

CALPUFF model for BART analyses. The CAMx modeling provides unit specific impacts and also total facility impacts where the CALPUFF modeling was performed such that only total facility impacts were generated. Therefore, we do not have unit specific CALPUFF results. Additional details regarding our approach to using CAMx and CALPUFF modeling are within Section VII.A.1 and the 2023 BART Modeling TSD.

To assess the visibility benefits of controls, we modeled the sources with emissions reflecting a low control level and a high control level.[290][291] For the low control level, we evaluated the visibility benefits of DSI for all the subject to BART units at each facility identified in Tables 12 and 13 that currently have no SO_2 control. For these low control levels, we modeled these units at a DSI SO_2 control level of 50 percent, which we believe is achievable for any unit. At this assumed control level, we expect that the corresponding visibility benefits from DSI in most cases would be close to half of the benefits from scrubbers, which are generally at a control level of 90 percent or greater from the baseline. For the high control level, we evaluated the visibility benefits for scrubber retrofits (wet FGD or SDA) for these same units, assuming the same control levels corresponding to SDA (for Harrington BART units) and wet FGD (for all other unscrubbed BART units) that we used in our control cost analyses. NOx and PM10 and PM2.5 emissions were held constant for the control case.

We also modeled the visibility benefits of improved efficiency on the existing scrubbers at Martin Lake. We assumed the same 95 percent control level represented by an emission limit

[290] As discussed in Section VIII.A and in the 2023 BART Modeling TSD, we completed some additional CALPUFF modeling for Welsh and Harrington units in addition to the low and high control scenarios. We also extrapolated CAMx results to estimate visibility benefits for SDA for units at Coleto Creek, W.A. Parish, and Welsh, and extrapolated CAMx results for Harrington Unit 61B for additional levels of control. See the 2023 BART Modeling TSD for discussion of all modeled and extrapolated visibility modeling.

[291] NOx and PM_{10}/$PM_{2.5}$ emissions were held constant at baseline emission levels for all emission units in order to isolate visibility improvements due to SO_2 reductions from any visibility benefits that would result from reductions in NOx emissions

of 0.08 lb/MMBtu used in our control cost analyses for the high control level. We also modeled a lower control level based on an emission rate of 0.32 lb/MMBtu. This emission rate is consistent with the limit included in an Agreed Order[292] between TCEQ and Luminant for purposes of addressing SO_2 NAAQS nonattainment requirements.[293]

As discussed in Section VII.B.1.b, Fayette Units 1 and 2 have scrubbers that are operating consistently at a high control level. Accordingly, we modeled both units at an emission rate of 0.04 lb/MMBtu for the high control level, which is consistent with emission rates from the past several years. For the low control scenario, we evaluated the visibility impacts at the current permitted emission rates, which is higher than the current actual emissions. These model runs do not correspond to "low control" and "high control" specifically. We discuss the model results for Fayette further in Section VIII.B. As discussed elsewhere, we found that for these units no additional controls or upgrades were necessary.

Tables 12 and 13 present a summary of the modeled visibility impacts for the baseline at the Class I areas most impacted by each source, and the visibility benefits from the low and high control scenarios, as predicted by CAMx[294] and CALPUFF. In evaluating the impacts and benefits of control options, we utilized a number of metrics, including change in deciviews on the maximum impacted day for CAMx results and annual 98th percentile for CALPUFF results, and also number of days impacted over 0.5 dv and 1.0 dv. In Section VIII, we provide some additional discussion of model results and additional metrics in weighing the visibility benefits

[292] Agreed Order 2021-0508-MIS, signed February 22, 2022, available in the docket for this action.

[293] The agreed order and accompanying SIP submittal remain before the EPA for review. In this action we are not taking a position on the approvability or appropriateness of the limits in the agreed order for purposes of addressing SO2 NAAQS nonattainment requirements.

[294] For the CAMx modeling, visibility was assessed using the grid cell containing the monitor representative of the Class I area. In 2016, Carlsbad Caverns shared a monitor with the Guadalupe Mountains and Pecos Wilderness shared a monitor with Wheeler Peak. Therefore, the modeled impacts and benefits at these receptors/monitors were applied to both Class I areas represented by that monitor site.

of controls. 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.[295] For a more detailed discussion of our review of all the modeling results and factors that we considered in evaluating and weighing results, including scrubber upgrades, see our 2023 BART FIP TSD and 2023 BART Modeling TSD.

Table 12: CAMx Modeling of Baseline Impacts and Visibility Benefits of Controls for Subject-to-BART Sources

	2016 Baseline Impacts			**Low Control Scenario**			**High Control Scenario**		
BART Source & Top 3 Class I areas	**Impact at Class I area (dv)**	**# days ≥0.5 dv**	**# days ≥1.0 dv**	**Benefit at Class I area (dv)**	**# days impacted ≥0.5 dv**	**# days impacted ≥1.0 dv**	**Benefit at Class I area (dv)**	**# days impacted ≥0.5 dv**	**# days impacted ≥1.0 dv**
Martin Lake Units 1, 2, and 3				(0.32 lb/MMBtu)			(0.08 lb/MMBtu)		
Caney Creek	6.69	150	101	3.28	97	46	5.00	32	7
Wichita Mountains	5.49	51	27	2.87	21	7	4.57	3	0
Upper Buffalo	5.16	111	70	2.78	61	25	4.39	7	0
Cumulative (all 15 Class I areas)	33.79	521	301	18.29	259	91	27.91	47	7
W. A. Parish Units WAP4, WAP5, and WAP6				(DSI @ 50%)			(wet FGD @ 0.04 lb/MMBtu)		
Wichita Mountains	3.97	35	12	1.73	15	1	3.61	0	0
Caney Creek	3.13	86	38	1.31	48	11	2.59	1	0
Breton	2.21	12	4	0.85	4	2	1.89	0	0
Cumulative (all 15 Class I areas)	17.96	269	91	7.76	119	18	15.66	1	0
Harrington Station Units 061B and 062B				(DSI @ 50%)			(SDA @ 0.06 lb/MMBtu)		
White Mountain	2.64	8	3	0.96	4	1	1.78	1	0
Bandelier	1.60	4	1	0.65	1	0	1.23	0	0
Salt Creek	1.52	13	6	0.49	7	1	0.97	1	0

[295] 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." For the specific calculations, see 2023 BART Modeling TSD for this action.

Cumulative (all 15 Class I areas)	12.77	44	10	5.01	13	2	9.08	2	0
Coleto Creek Unit 1				(DSI @ 50%)			(wet FGD @ 0.04 lb/MMBtu)		
Caney Creek	1.55	18	2	0.67	2	0	1.38	0	0
Breton	1.19	4	1	0.50	1	0	1.08	0	0
Wichita Mountains	1.13	23	3	0.54	4	0	1.00	0	0
Cumulative (all 15 Class I areas)	8.54	69	6	3.92	9	0	7.75	0	0
Welsh Unit 1				(DSI @ 50%)			(wet FGD @ 0.04 lb/MMBtu)		
Caney Creek	1.58	27	6	0.48	8	1	1.08	0	0
Wichita Mountains	1.54	6	2	0.69	2	0	1.34	0	0
Upper Buffalo	1.12	8	1	0.40	2	0	0.83	0	0
Cumulative (all 15 Class I areas)	6.67	46	9	2.60	13	1	5.27	0	0

To further illustrate the CAMx modeled visibility benefits provided by both the low and high control levels, we compared the visibility benefits of the low and high control levels to the baseline impacts in terms of percent reduction in visibility impacts. To make this comparison, we used the maximum impact for each Class I area and compared these values for the low control and high control with the baseline impacts, looking at the values for the highest impacted Class I area and the average of the 15 Class I areas from the baseline modeling to show the benefit for the control levels. For Martin Lake, low and high control resulted in a reduction of visibility impacts at Caney Creek by 49 percent and 75 percent, respectively, and an average reduction of visibility impacts at the 15 Class I areas of 54 percent and 83 percent, respectively. For W.A. Parish, low and high control resulted in a reduction of visibility impacts at Wichita Mountains by 44 percent and 91 percent, respectively, and an average reduction of visibility impacts at the 15 Class I areas of 43 percent and 87 percent, respectively. For Harrington, low and high control resulted in a reduction of visibility impacts by 36 percent and 67 percent, respectively, and an average reduction of visibility impacts at the 15 Class I areas of 39 percent and 71 percent, respectively. For Coleto Creek, low and high control resulted in a reduction of visibility impacts by at Caney Creek 43 percent and 89 percent, respectively, and an average reduction of visibility impacts at the 15 Class I areas of 46 percent and 91 percent, respectively. For Welsh, low and high control resulted in a reduction of visibility impacts at Caney Creek by 30 percent and 68 percent, respectively, and an average reduction of visibility impacts at the 15 Class I areas of 39 percent and 79 percent, respectively. For Fayette, high control resulted in a reduction of visibility impacts at Caney Creek by 0 percent and an average reduction of visibility impacts at the 15 Class I areas of 5 percent. We provide additional analysis of the visibility benefits of the different control levels in Section VIII and in the 2023 BART FIP TSD and 2023 BART Modeling TSD.

For each of the facilities, CAMx predicted a large decrease in the number of days with visibility impacts greater than 0.5 dv with the high level of controls. Aside from impacts on the Caney Creek Class I area, CAMx predicted zero days over 1.0 dv with the high level of controls on the Martin Lake facility. Additional unit-specific information for these sources can be found in the 2023 BART Modeling TSD.

Table 13: CALPUFF Modeling Baseline Impact and Visibility Benefit of Controls for Subject-to-BART Sources *

BART Source & Class I Area	2016-18 Baseline				Low Control Scenario				High Control Scenario			
					Benefit at Class I Area (dv)			**Cumulative 2016-18 # of Days with impacts ≥ 0.5 dv/ ≥1.0 dv**	**Benefit at Class I Area (dv)**			**Cumulative 2016-18 # of Days with impacts ≥ 0.5 dv/ ≥1.0 dv**
	2016 dv	2017 dv	2018 dv	Cumulative 2016-18 # of Days with impacts ≥ 0.5 dv/ ≥1.0 dv	2016 dv	2017 dv	2018 dv		2016 dv	2017 dv	2018 dv	
Martin Lake Units 1, 2, and 3					(0.32 lb/MMBtu)				(0.08 lb/MMBtu)			
Caney Creek	3.28	3.60	3.35	338/215	1.62	1.78	1.75	222/95	2.12	2.36	2.16	133/44
Upper Buffalo	2.12	2.54	2.27	212/115	1.12	1.39	1.10	100/29	1.58	1.90	1.72	33/8
Wichita Mountains	1.45	1.07	1.15	79/36	0.80	0.58	0.65	25/4	1.21	0.89	0.91	5/2
Welsh Unit 1					(DSI @ 50%)				(wet FGD @ 0.04 lb/MMBtu)			
Caney Creek	0.70	0.94	0.96	77/13	0.17	0.30	0.32	41/3	0.28	0.37	0.53	18/1
Upper Buffalo	0.36	0.49	0.60	16/0	0.14	0.17	0.22	3/0	0.25	0.33	0.42	0/0
Wichita Mountains	0.25	0.35	0.24	3/0	0.09	0.17	0.08	1/0	0.17	0.28	0.16	0/0
Harrington Station Units 061B and 062B					(DSI @ 50%)				(SDA @ 0.06 lb/MMBtu)			
Carlsbad Caverns	0.39	0.41	0.56	16/5	0.12	0.16	0.15	7/1	0.24	0.27	0.31	1/1
Bandelier	0.17	0.12	0.14	2/0	0.06	0.04	0.05	0/0	0.12	0.09	0.11	0/0
Pecos	0.22	0.28	0.24	9/0	0.08	0.09	0.09	3/0	0.15	0.17	0.16	0/0
Salt Creek	0.49	0.59	0.54	27/3	0.13	0.22	0.19	14/1	0.23	0.39	0.32	2/0
Wheeler Peak	0.12	0.15	0.16	2/0	0.03	0.05	0.06	0/0	0.07	0.10	0.11	0/0
White Mountain	0.26	0.43	0.33	7/0	0.09	0.15	0.13	1/0	0.17	0.26	0.24	0/0

Wichita Mountains	0.54	0.45	0.58	24/8	0.19	0.16	0.18	12/0	0.35	0.23	0.33	3/0

* Benefit of control values are the decrease in deciview between baseline and the control scenario. Number of days is the number of days that are equal or greater than 0.5 and 1.0 dv after controls.

As discussed in prior sections, when using CALPUFF, the visibility benefit (dv) is derived from the 98th percentile (eighth highest day for each year) for each Class I area. We provide additional analysis of the benefits of the different control levels in Section VIII and in the 2023 BART FIP TSD and 2023 BART Modeling TSD. As shown in Table 13, CALPUFF predicted large reductions in the number of days over the 1.0 dv threshold under the high control level for all three facilities. For Harrington, CALPUFF results predicted one day with visibility impacts over 1.0 dv compared to baseline impacts of 16 days. For Welsh, CALPUFF results predicted only one day over 1.0 dv compared to baseline impacts of 16 days. For Martin Lake, CALPUFF results predicted 54 days over 1.0 dv compared to baseline impacts of 366 days.

To further illustrate the CALPUFF modeled visibility benefits provided by both the low and high control levels, we also compared the visibility benefits of the low and high control levels to the baseline impacts in terms of percent reduction in visibility impacts as we did in analyzing CAMx benefits. To make this comparison, we first calculated the average of the 98th percentile for the three years modeled for each Class I area. We then compared these values for the low control and high control with the baseline impacts, looking at the values for the highest impacted Class I area and the average of the Class I areas from the baseline modeling to show the benefit for the control levels. For Harrington, Salt Creek was the highest impacted of the seven Class I areas and low and high control resulted in a reduction of visibility impacts by 33 percent and 58 percent, respectively, and an average reduction of visibility impacts at the seven

Class I areas of 34 percent and 61 percent, respectively. For Martin Lake, Caney Creek was the highest impacted of the three Class I areas and low and high control resulted in a reduction of visibility impacts by 50 percent and 65 percent, respectively, and an average reduction of visibility impacts at the three Class I areas of 52 percent and 71 percent, respectively. For Welsh, Caney Creek was the highest impacted of the three Class I areas and low and high control resulted in a reduction of visibility impacts by 30 percent and 45 percent, respectively and an average reduction of visibility impacts at the three Class I areas of 34 percent and 57 percent, respectively. As further discussed in the 2023 BART Modeling TSD, CALPUFF model results are not directly comparable to CAMx results due to difference in the modeling analysis as discussed elsewhere (years modeled, receptor(s) modeled, etc.) and difference in the model including the simplified chemistry in CALPUFF. The potential to overestimate nitrate impacts in the CALPUFF model may limit (resulting in an underestimation) the amount of modeled visibility benefits (improvement) on both the 98th percentile days and the number of days above a threshold that result from decreases in SO_2 emissions.

5. BART Five Factor Analysis for PM

In our 2017 Texas BART FIP, we approved Texas's determination in its 2009 Regional Haze SIP 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 emissions were covered by the Texas SO_2 Trading Program and NO_X emissions were covered by participation in CSAPR (allowing consideration of PM emissions in isolation). For reasons provided for in Section VI, we are now proposing that our approval was in error and are correcting that error by disapproving the portion of the SIP regarding PM BART for EGUs.

Based on this proposed disapproval, the FIP we are proposing to address BART requirements for those Texas EGUs that are subject to BART will cover PM BART.

The BART Guidelines permit us to conduct a streamlined analysis of PM BART 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.[296] 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 coal-fired EGUs that are subject to BART are currently equipped with either Electrostatic Precipitators (ESPs) or baghouses, or both, as illustrated in Table 14:

Table 14: Current PM Controls for Coal-Fired Units Subject to BART[297]

Facility Name	**Unit ID**	**Fuel Type (Primary)**	**SO_2 Control(s)**	**PM Control(s)**
Coleto Creek	1	Coal		Baghouse
Harrington Station	061B	Coal		Electrostatic Precipitator
Harrington Station	062B	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
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

[296] 70 FR at 39163-64.
[297] www.eia.gov/electricity/data/eia860/.

Welsh Power Plant	1	Coal		Baghouse (Began Nov 15, 2015) + Electrostatic Precipitator

We began our analysis by examining the control efficiencies of both baghouses and ESPs. When considering the units controlled by a baghouse, they were widely reported to be capable of achieving 99.9 percent control of PM, which is the maximum level of control for PM. Therefore, 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 design, resistivity of the particulate matter, and maintenance of the ESP. We do not have information specifically 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 percent to 99.9 percent.[298] We therefore consider this pertinent when concluding that the potential additional particulate control that a baghouse can offer over an ESP is relatively minimal.[299] Accordingly, even if we did obtain additional control information specific to the ESP units in question, we do not expect the additional information would result in a different conclusion.

Nevertheless, we 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 6 of our IPM model,[300] and assuming a conservative air to cloth ratio of 6.0, the results for capital

[298] 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.

[299] 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.

[300] IPM Model – Updates to Cost and Performance for APC Technologies, Particulate Control Cost Development Methodology, Final April 2017, Project 13527-001, Eastern Research Group, Inc., Prepared by Sargent & Lundy. Documentation for v.6: Chapter 5: Emission Control Technologies, Attachment 5-7: PM Cost Methodology, downloaded from: https://www.epa.gov/sites/default/files/2018-05/documents/attachment_5-7_pm_control_cost_development_methodology.pdf.

engineering and construction costs are $84,770,000.[301] For the purposes of analyzing 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 did not calculate the cost-effectiveness resulting from replacing an ESP with a baghouse because 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. For this reason, we did not model the visibility benefit of replacing an ESP with a baghouse. As noted previously, our visibility impact modeling indicates that the contributions to visibility impairment from the baseline PM emissions of these units are very small, and thus we expect the visibility improvement from replacing an ESP with a baghouse to be minimal. For instance, our CAMx baseline modeling shows that on a source-wide level, impacts from PM emissions on the maximum impacted days was at most 7 percent in the case of Fayette, a few were near 1 percent, and others were less than 1 percent of the total visibility impairment, as calculated as the percent of total extinction due to the source(s) at each subject to BART facility. Similarly, our CALPUFF modeling indicates that visibility impairment from PM is also a small fraction (at most 3 percent for Harrington) of the total visibility impairment due to each source. Therefore, additional PM controls are anticipated to result in very little visibility benefit on the maximum impacted days.

Accordingly, we believe an appropriately stringent PM BART control level that would be met with existing, or otherwise-required, controls is a filterable PM limit of 0.030 lb/MMBtu for each of the coal-fired units subject to BART. This limit is consistent with the Mercury and Air Toxics (MATS) Rule, which establishes an emission standard of 0.030 lb/MMBtu filterable PM

[301] *Id.* See page 11.

(as a surrogate for toxic non-mercury metals) as representing Maximum Achievable Control Technology (MACT) for coal-fired EGUs.[302] 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. 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.[303] 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.[304] Because we anticipate 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 invite comment on alternate or additional methods of demonstrating compliance.

BART Analysis for PM for Gas-Fired Units

As explained in Section VII.A, W. A. Parish Unit WAP4 is the only gas fired unit that we are proposing to find subject to BART. With respect to gas-fired units, which have inherently

---

[302] 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.
[303] 70 FR at 39163-64.
[304] The various limits are provided at 40 CFR Part 63, Subpart UUUUU, Table 2 (“Emission Limits for Existing EGUs”).

low emissions of PM (as well as SO_2)[305], the RHR did not specifically envision new or additional controls or emissions reductions from the PM BART requirement.[306] The BART Guidelines preclude us from stating that PM emissions are *de minimis* when plant-wide emissions exceed 15 tons per years.[307] In assigning a PM BART determination to the W. A. Parish Unit WAP4, there are no practical add-on controls to consider for setting a more stringent PM BART emission limit than what is already required of the unit, and therefore, the status quo reflects the most stringent controls. 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.[308] Thus, we are proposing that PM BART for W. A. Parish Unit WAP4 is to limit fuel to pipeline natural gas, as defined at 40 CFR 72.2.

VIII. Weighing of the Five BART Factors and Proposed BART Determinations

In this section, we present our reasoning for our proposed BART determinations for 12 EGUs in Texas, based on our analysis and weighing of the five statutory BART factors for the following unit types: (1) proposed SO_2 and PM BART determinations for 6 coal-fired units with no SO_2 controls, and (2) proposed SO_2 and PM BART determinations for 5 coal-fired units with existing scrubbers, and (3) proposed SO_2 and PM BART determination for the gas-fired unit (W. A. Parish Unit WAP4).

In previous sections of this proposal, we have described how we assessed the five BART factors. We will now discuss how we weigh these factors in our BART determinations. As a general matter, cost effectiveness and visibility benefits are the driving factors for most of our

---

305 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.
306 *See* 70 FR at 39165.
307 70 FR at 39116-17.
308 70 FR at 39165 (''. . . you may skip the remaining analyses in this section, including the visibility analysis . . .'').

BART determinations. However, site specific considerations can impact the evaluation of control options and establishing an appropriate BART limit. As defined in the BART Guidelines, "BART means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by . . . [a BART-eligible source]." Through this process, we will establish emission limits that represent a system of continuous emission reduction for specific pollutants based on consideration of the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

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. 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.[309] We consider visibility improvement in a holistic manner, taking into account all reasonably anticipated improvements in visibility expected to result at all impacted Class I areas. As explained in Section VII.A, and in accordance with the BART Guidelines, a source with a modeled 0.5 dv impact at a single Class I area "contributes" to visibility impairment and must be

[309] *See* 70 FR at 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.)."

analyzed for BART controls. Controlling individual units to reduce emissions of a visibility impairing pollutant, such as SO_2, at such a source will address only a fraction of the total visibility impairment and will not result in perceptible improvements (~1 dv improvement) or visibility improvements greater than 0.5 dv. However, when considered in the aggregate, small improvements from controls on multiple sources will lead to visibility progress.

The visibility benefits and 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 BART actions nationwide, with the exception of SDA on Harrington Unit 061B which is discussed in further detail in Section VIII.A.2.a.[310] As we stated in the BART Rule, a reasonable range would be a range that is consistent with cost effectiveness values used in other similar decisions over a period of time.[311] We looked at past BART actions to assess the upper range of cost effectiveness values that have previously been found to be acceptable. In past BART decisions, several controls were required by either EPA or states as BART with average cost-effectiveness values in the $4,200 to $5,100/ton range (escalated to 2020 dollars) and visibility benefits of 0.26 to 0.83 dv. For instance, the EPA promulgated a FIP for Arkansas where we made the determination that SO_2 BART for Flint Creek Unit 1 is an SO_2 emission limit based on dry scrubbers at a cost of $3,845/ton, which is $4,232/ton escalated to 2020 dollars using the CEPCI, and estimated to result in visibility benefit of 0.615 dv at the Class I area with the greatest

[310] *See* for instance 77 FR 18070 (March 26, 2012): the EPA proposed approval of Colorado's NO_X BART determination of SCR for Hayden Unit 2, later finalized at 77 FR 76871 (December 31, 2012). The estimated cost of SCR at Hayden Unit 2 is $4,064/ton ($4,211/ton when escalated from 2008 dollars to 2020 dollars) and anticipated to result in visibility benefit of 0.85 dv at the Class I area with greatest visibility benefit. We escalated this cost-effectiveness value using the following equation: Cost-effectiveness escalated to 2020 dollars = Cost-effectiveness in 2008 dollars x (2020 CEPCI/2008 CEPCI).

[311] 70 FR at 39168 (July 6, 2005).

visibility benefit.[312, 313] The EPA also promulgated a FIP for Wyoming where we made the determination that NO_X BART for Laramie River Units 1, 2, and 3 is a NO_X emission limit based on LNB with SOFA and Selective Catalytic Reduction (SCR) at a cost per unit ranging from $4,375 to $4,461/ton, which is $4,599 to $4,689/ton escalated to 2020 dollars, and estimated to result in visibility benefit ranging from 0.52 to 0.57 dv per unit at the Class I area with the greatest visibility benefit.[314, 315] In that Wyoming Regional Haze FIP, we explained the following:

> In regards to the costs of compliance, we found that the revised average and incremental cost-effectiveness of LNB/ SOFA + SCR is in line with what we have found to be acceptable in our other FIPs. The average cost-effectiveness per unit ranges from $4,375 to $4,461/ton, while the incremental cost-effectiveness ranges from $5,449 to $5,871/ton. We believe that these costs are reasonable, especially in light of the significant visibility improvement associated with LNB/SOFA + SCR. As a result, we are finalizing our proposed disapproval of the State's NO_X BART determination for Laramie River Station and finalizing our proposed FIP that includes a NO_X BART determination of LNB/SOFA + SCR, with an emission limit of 0.07 lb/MMBtu (30-day rolling average).[316]

In addition, the EPA approved several BART SIP decisions that required controls with similar cost-effectiveness values. For example, the EPA approved Colorado's determination that NO_X BART for the Colorado Energy Nations Company Unit 5 is a NO_X emission limit based on Low NO_X burners (LNB) with Separated Overfire Air (SOFA) and Selective Non-Catalytic

---

[312] *See* the EPA's proposed Arkansas Regional Haze FIP at 80 FR 18944 (April 8, 2015), later finalized at 81 FR 66332 (September 27, 2016). The Arkansas Regional Haze FIP was later replaced with a SIP revision submitted by Arkansas that included the same SO_2 BART determination for Flint Creek Unit 1. See the EPA's approval of Arkansas Regional Haze SIP Revision at 84 FR 51033 (September 27, 2019).
[313] The year basis for the EPA's cost-effectiveness calculation is 2016. We escalated the cost-effectiveness value from 2016 dollars to 2020 dollars using CEPCI and the following equation: Cost-effectiveness escalated to 2020 dollars = Cost-effectiveness in 2016 dollars x (2020 CEPCI/2016 CEPCI); 2016 CEPCI = 541.7, 2020 CEPCI = 596.2.
[314] *See* the EPA's Wyoming Regional Haze FIP at 79 FR 5032 (January 30, 2014).
[315] The year basis for the EPA's cost-effectiveness calculations is 2013. We escalated the cost-effectiveness value from 2013 dollars to 2020 dollars using the CEPCI and the following equation: Cost-effectiveness escalated to 2020 dollars = Cost-effectiveness in 2013 dollars x (2020 CEPCI/2013 CEPCI); 2013 CEPCI = 567.2, 2020 CEPCI = 596.2.
[316] *See* 79 FR at 5047-48.

Reduction (SNCR) at a cost of $4,918/ton, which is $5,096/ton escalated to 2020 dollars, and estimated to result in visibility benefit of 0.26 dv at the Class I area with the greatest visibility benefit.[317, 318] The EPA also approved Colorado's determination that NO_X BART for Tri-State Craig Unit 1 is a NO_X emission limit based on SNCR at a cost of $4,877/ton, which is $5,053/ton escalated to 2020 dollars, and estimated to result in visibility benefit of 0.31 dv at the Class I area with the greatest visibility benefit.[319, 320] The EPA approved Kentucky's determination that PM BART for Mill Creek Station Units 3 and 4 is an emission limit based on sorbent injection at a cost of $4,293/ton for Unit 3 and $4,443/ton for Unit 4, which is $4,872/ton and $5,042/ton escalated to 2020 dollars (respectively), and estimated to result in visibility benefit of 0.83 dv for both units combined at the Class I area with the greatest visibility benefit.[321, 322] In these BART determinations, the EPA and states found that the evaluated controls were reasonable based on the weighing of the five factors (including cost-effectiveness and visibility benefits).

A. SO_2 BART for Coal-fired Units with no SO_2 Controls

In this section, we compare DSI, SDA, and wet FGD using the five BART factors for the six coal-fired units with no SO_2 controls. As discussed in Section VII.B.2 and in our TSD, we evaluated each unit at its assumed maximum achievable DSI performance level using milled

---

[317] See the EPA's proposed approval of Colorado Regional Haze SIP at 77 FR 18052, later finalized at 77 FR 76871.

[318] The year basis for Colorado's cost-effectiveness calculation is 2008. We escalated the cost-effectiveness value from 2008 dollars to 2020 dollars using the CEPCI and the following equation: Cost-effectiveness escalated to 2020 dollars = Cost-effectiveness in 2008 dollars x (2020 CEPCI/2008 CEPCI); 2008 CEPCI = 575.4, 2020 CEPCI = 596.2.

[319] See the EPA's proposed approval of Colorado Regional Haze SIP at 77 FR 18052, later finalized at 77 FR 76871.

[320] The year basis for Colorado's cost-effectiveness calculation is 2008. We escalated the cost-effectiveness value from 2008 dollars to 2020 dollars using the CEPCI and the following equation: Cost-effectiveness escalated to 2020 dollars = Cost-effectiveness in 2008 dollars x (2020 CEPCI/2008 CEPCI); 2008 CEPCI = 575.4, 2020 CEPCI = 596.2.

[321] See the EPA's proposed approval of Kentucky Regional Haze SIP at 76 FR 78194 (December 16, 2011), later finalized at 77 FR 19098 (March 30, 2012).

[322] The year basis for Kentucky's cost-effectiveness calculations is 2007. We escalated the cost-effectiveness value from 2007 dollars to 2020 dollars using the CEPCI and the following equation: Cost-effectiveness escalated to 2020 dollars = Cost-effectiveness in 2007 dollars x (2020 CEPCI/2007 CEPCI); 2007 CEPCI = 525.4, 2020 CEPCI = 596.2.

trona according to the April 2017 IPM DSI documentation, which corresponds to 90 percent for units with an existing fabric filter baghouse and 80 percent for units with an ESP.[323,324] All units we evaluated for DSI have an existing baghouse, with the exception of Harrington Unit 061B, which has an ESP. Since we do not have site-specific information and individual DSI performance testing, we do not know with certainty whether the EGUs we are evaluating in this proposal are capable of achieving the assumed maximum DSI performance levels specified in the April 2017 IPM DSI documentation. Taking this into account, and recognizing that DSI has a wide range of SO_2 removal efficiencies, we also evaluated all units at a DSI SO_2 control level of 50 percent, which we believe is a conservatively low DSI control efficiency that any given coal-fired EGU is likely capable of achieving without requiring high sorbent injection rates that may negatively impact the performance of the particulate control device. Evaluating a range of control levels better informs our analysis of control options by providing a range of costs. Additionally, this approach addresses 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."[325]

For the units with existing baghouses where we evaluated DSI at 50 percent and 90 percent control, in comparing the 50 percent control level to the higher control level, we found DSI to have similar or slightly higher (up to around 10 percent higher) $/ton average cost-

---

323 IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology, Final April 2017, Project 13527-001, Eastern Research Group, Inc., Prepared by Sargent & Lundy.

324 Note for Harrington Unit 062B and Welsh Unit 1, we further limited the maximum DSI control level to that of our calculated SDA control level of 89 percent and 87 percent, respectively.

325 70 FR 39166 (July 6, 2005).

effectiveness at 90 percent control compared to 50 percent control.[326] This is due to higher annual operation and maintenance costs associated with increased sorbent usage, as well as higher capital costs. Similarly, for Harrington Unit 061B, which is the only unit we evaluated that has an existing ESP rather than a baghouse, we found DSI to have a slightly higher $/ton on average at 80 percent control compared to 50 percent control. While the cost-effectiveness of DSI in certain cases had a slightly higher $/ton, when going from 50 percent to 80/90 percent control efficiency, DSI at 80/90 percent control efficiency offered much greater SO_2 reductions and higher resulting visibility benefits compared to 50 percent control efficiency. For all units evaluated, DSI at both 50 percent and 80/90 percent control efficiency has a lower cost-effectiveness ($/ton) than SDA and wet FGD. However, because of the lack of site-specific information and related uncertainty over whether the specific units we are evaluating can achieve these assumed maximum achievable DSI performance levels, which we discuss in Section VII.B.2.a, we place much greater weight on our evaluation of DSI at 50 percent control efficiency compared to 80/90 percent control efficiency. There is also additional potential uncertainty in our cost estimates for DSI at these high performance levels. For the units with existing fabric filters, we do not know how frequently fabric filter bags would need to be cleaned and replaced or whether additional fabric filter compartments are necessary at these high DSI performance levels and so our cost estimates do not include these potential additional costs. For Harrington Unit 061B (the only unit with an existing ESP), our cost estimate for DSI at 80 percent control efficiency does not include the cost of a new ESP or fabric filter even though we do not know with certainty whether the existing ESP would be able to handle the high sorbent injection rates needed at high SO_2 removal efficiency. Therefore, without additional site-specific

---

[326] Harrington Unit 062B and Welsh Unit 1 show small improvement in cost effectiveness at the higher level of DSI control.

information regarding the range of maximum control efficiency achievable and associated costs needed to consider DSI at higher control levels, we are not further considering DSI at 80/90 percent control efficiency in our weighing of the factors. We welcome site-specific information and comments on the potential for these units to consistently achieve DSI SO_2 control efficiencies much higher than 50 percent (which may be as high as 80 to 90 percent).

In comparing DSI at 50 percent control level with SDA and wet FGD, we found that DSI at the 50 percent control level was more cost-effective than either SDA or wet FGD. In general, DSI systems have low capital costs in comparison to SDA or wet FGD. At 50 percent control level, the ongoing annual operation and maintenance costs of DSI are comparable to those of SDA and wet FGD. Given the relatively low initial capital costs of DSI as compared to the installation of SDA or wet FGD, DSI may be a more favorable control option from a cost perspective for a coal-fired EGU that may have plans to retire in the next several years. However, we are not aware of any federally enforceable and permanent commitment to cease operations for these sources that would impact the remaining useful life of controls. Therefore, we do not place extra weight on the capital cost benefit of DSI at 50 percent control over the visibility benefit gained by SDA. In considering CAMx modeled visibility benefits, wet FGD and SDA provide approximately twice the amount of visibility benefits as DSI at 50 percent control level. Additionally, for all units, with the exception of Harrington Unit 061B, we conclude that scrubbers are approximately \$4,900/ton or less, and thus within the range we regularly find to be cost-effective. We are proposing to find that, with the possible exception of Harrington Unit 061B, the resulting visibility benefit offered by scrubbers outweighs any possible advantage DSI at 50 percent control may hold in terms of cost-effectiveness. At higher control efficiencies, DSI may become more favorable as the difference in visibility benefits between DSI and SDA or wet FGD decreases and estimated cost-effectiveness for DSI even at higher control is estimated to be less than that for SDA or wet FGD, resulting in increasing incremental costs between DSI and scrubbers. However, as noted elsewhere, there is uncertainty as to what DSI control efficiencies are achievable for these particular units and the associated costs at these higher control efficiencies. We will further consider site-specific information provided to us during the public comment period in making our final decision on SO_2 BART and potentially re-evaluate DSI for one or more particular units.

As we indicate elsewhere in our proposal, both SDA and wet FGD are mature technologies that are in wide use throughout the United States. In comparing wet FGD versus SDA, wet FGD is slightly less cost-effective than SDA in all cases evaluated for this proposed action. Wet FGD has slightly higher SO_2 removal efficiency than SDA and generally requires lower reagent usage and has lower associated reagent costs than a comparable dry scrubber. However, as the Control Cost Manual explains, "In general, dry scrubbers have lower capital and operating costs than wet scrubbers because dry scrubbers are generally simpler, consume less water and require less waste processing."[327] The Control Cost Manual also notes that SDA has lower auxiliary power usage and lower water usage than wet FGD and does not require any wastewater treatment, unlike a wet FGD.[328] These factors all contribute to the generally lower capital and operating costs of SDA compared to wet FGD. Further, the wet FGD cost algorithms were updated in version 6 of our IPM model to incorporate the capital and operating costs of a wastewater treatment facility for all wet FGDs. The IPM wet FGD Documentation states:

Industry data from "Current Capital Cost and Cost-effectiveness of Power Plant

[327] EPA Air Pollution Control Cost Manual, Seventh Edition, April 2021, Section 5, Chapter 1, titled "Wet and Dry Scrubbers for Acid Gas Control," page 1-11. The EPA Air Pollution Control Cost Manual is available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual.
[328] *Id.* At 1-3 and 1-4.

> Emissions Control Technologies" prepared by J. E. Cichanowicz for the Utility Air Regulatory Group (UARG) in 2012 to 2014 were used by Sargent & Lundy LLC (S&L) to update the wet FGD cost algorithms from 2013. The published data were significantly augmented by the S&L in-house database of recent wet FGD and wet FGD wastewater treatment system projects. Due to recently published Effluent Limitation Guidelines (ELG), it is expected that all future wet FGDs will have to incorporate a wastewater treatment facility.[329]

The anticipated need for a wastewater treatment facility for all future wet FGDs also contributes to the higher capital and operating costs of wet FGD compared to SDA. We discuss the cost differences and the factors that result in wet FGD being slightly less cost-effective than SDA for the evaluated units in greater detail in our 2023 BART FIP TSD. We solicit comment on any additional factors or information that may affect the costs of wet FGD and/or SDA for the evaluated units and weigh in favor of one control option or the other. Although wet FGD would offer slightly greater SO_2 emission reductions compared to SDA, that the estimated visibility benefits of the two control options are very similar in all cases. In consideration of the additional costs and non-air environmental impacts associated with wet FGD, we propose to conclude that, based on a weighing of these factors, the selection of SDA is appropriate for Coleto Creek Unit 1, W. A. Parish Units WAP5 and WAP6, Welsh Unit 1, and Harrington Unit 062B. We propose that SO_2 BART should be based on the emission limit associated with SDA control levels. For those units with existing fabric filters, DSI could potentially meet the same emission limitations as SDA but this would need to be confirmed with site-specific performance testing. For Harrington Unit 061B, as discussed in Section VIII.A.2., there are unique circumstances that impact the evaluation of controls. For this unit, we propose that SO_2 BART should be an emission limit based on SDA and we propose in the alternative an emission limit based on DSI at

[329] IPM Model – Updates to Cost and Performance for APC Technologies, Wet FGD Cost Development Methodology, Final January 2017, Project 13527-001, Eastern Research Group, Inc., Prepared by Sargent & Lundy, p. 1.

50 percent control level.

We discuss in further detail our consideration of the cost-effectiveness and anticipated visibility benefits of controls for each of the facilities. Tables 15 thru 17 and 19 thru 26 provide summary CAMx and CALPUFF model results of the benefits from the recommended BART controls. The CAMx model results shown in the following tables for each evaluated BART source summarize the benefits from the recommended controls at the three 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.

In addition to these metrics, to further inform the impacts and potential benefits of emission reductions, we also provide the average of modeled potential impacts from CAMx on a broader set of high impact days. The CAMx model results tables include the average impact across the top ten highest impacted days at the most impacted class I areas (and cumulative across all Class I areas) for the baseline and the recommended control scenario, as well as the calculated visibility benefits, to assess the potential visibility benefits that could be anticipated due to controls during the ten days with meteorological/transport conditions that result in the largest visibility impacts. These varying conditions affect the reaction rates and transport of pollutants which can be simulated within the photochemical grid model. While the BART analysis is focused on examination of the maximum potential visibility impairment and benefits, these additional metrics provide a sense for the potential benefit across days other than just the maximum impact day.

For Coleto Creek, Parish and Welsh units, we also present the benefits of SDA control levels for comparison with wet FGD, though these SDA control levels were not directly modeled in CAMx. To evaluate SDA control levels using the available CAMx model results, we calculated an estimate of the visibility benefits using a mathematical extrapolation method, which is further discussed in the 2023 BART Modeling TSD.

The CALPUFF model results in the following tables for the evaluated BART sources include the 98th percentile modeled impact and the number of days impacted over 0.5 and 1.0 dv for those Class I areas within the range of CALPUFF typically used for BART. See the 2023 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, plus additional metrics considered in the assessment of visibility benefits.

1. Coleto Creek Unit 1

In reviewing Coleto Creek Unit 1, we conclude that the installation of SDA or wet FGD results in significant visibility benefits. We summarize some of these visibility benefits in Table 15 and discuss them after the table.

Table 15. CAMx-predicted Wet FGD *(SDA)* Visibility Benefits at Coleto Creek Unit 1

Coleto Creek Unit 1	BASELINE	CONTROLLED

Class I area	Impact (dv) on the Maximum Impact Day	Avg Impact (dv) for the Top 10 Days	Number of Days ≥0.5 / ≥1.0 dv	Visibility Improvement (dv) on the Maximum Impact Day*	Avg Visibility Improvement (dv) for the Top 10 Days*	Impacted Number of Days ≥0.5 / ≥1.0 dv
Caney Creek	1.55	0.89	18 / 2	1.38 *(1.34)*	0.80 *(0.78)*	0 / 0
Breton	1.19	0.47	4 / 1	1.08 *(1.05)*	0.43 *(0.42)*	0 / 0
Wichita Mountains	1.13	0.86	23 / 3	1.00 *(0.98)*	0.79 *(0.76)*	0 / 0
Cumulative (all Class I areas)	8.54	5.14	69 / 6	7.75	4.71	0 / 0

* Secondary values in parentheses indicate estimated visibility benefits for SDA

The visibility benefits predicted by CAMx with wet FGD control levels applied to Coleto Creek Unit 1 are summarized in Table 15. We also present the estimated benefits of SDA (shown in parentheses) for the visibility improvement at the top three impacted Class I areas. The small difference in visibility benefits between SDA and wet FGD is consistent with the relatively small difference in control efficacy, with an estimated difference between wet FGD and SDA on the maximum impacted day of 0.04 dv at Caney Creek and an average top 10 days difference of 0.02 dv at Caney Creek and Wichita Mountains.

CAMx modeling results indicate that wet FGD will eliminate all 69 days impacted over 0.5 dv across all Class I areas. At each of the three most impacted Class I areas (Caney Creek, Breton, and Wichita Mountains), wet FGD will result in visibility improvements of more than 1.0 dv on the maximum impacted days at each Class I area, and for the average of the top 10 most impacted days, CAMx predicts an average improvement of 0.43 to 0.80 dv at those same three Class I areas. Overall, there is a cumulative improvement to the average of the top 10 impacted days of approximately 4.7 dv with wet FGD across all impacted Class I areas and 7.7 dv cumulative improvement on the maximum impacted day. When compared to wet FGD, we estimate that SDA will result in very similar visibility benefits, ranging from 0.98 to 1.34 dv at the three most impacted Class I areas on the maximum impacted days and an average improvement of 0.42 to 0.78 dv at those same three Class I areas for the average of the top 10 most impacted days. See the 2023 BART Modeling TSD for more information on our estimation of the visibility benefits of SDA. Additional evaluation of the visibility benefits of DSI are presented in the 2023 BART Modeling TSD, but in summary, we find that DSI averaged 46 percent reduction in cumulative visibility impacts at the Class I areas, while wet FGD averaged 91 percent reduction in cumulative visibility impacts overall on the most impacted days. At Caney Creek (highest baseline maximum impact of 1.55 dv), DSI results in improvement on the maximum impacted day of 0.66 dv compared to 1.38 dv for wet FGD and 1.34 dv for SDA. Thus, we conclude that the resulting visibility benefit offered by scrubbers outweighs the possible advantage DSI at 50 percent control may hold in cost-effectiveness.

We also conclude that both SDA and wet FGD are cost-effective at $2,692/ton and $2,911/ton (respectively) and, as discussed in Section VIII, well within a range that we have previously found to be acceptable. Wet FGD is less cost-effective than SDA and we estimate that it would have only a slight additional visibility benefit over SDA. As discussed earlier, in weighing the factors between SDA and wet FGD, we determined the additional visibility benefits did not outweigh the additional cost, water requirements, and wastewater treatment requirements associated with wet FGD. We consider the significant visibility benefits that will result as justification for the cost of SDA at the Coleto Creek Unit 1. We therefore propose that SO_2 BART for Coleto Creek Unit 1 is an emission limit of 0.06 lbs/MMBtu on a 30 BOD rolling average based on the installation of SDA.

2. Harrington Units 061B & 062B

From our identification of available controls, we conclude that both DSI and SDA are technically feasible on both Harrington units. Harrington Unit 061B is distinct from the other coal-fired units we evaluated in that it has an existing ESP rather than a fabric filter. Additionally, this unit had relatively low utilization at times during the 2016 – 2020 baseline we used in our BART analysis, which has resulted in a cost per SO_2 tons removed for SDA that is relatively high compared to the other units evaluated for SDA. Based on these facts, we are proposing and taking comment on two alternative BART determinations. We are proposing BART is an emission limit reflective of the installation and operation of SDA on both Unit 061B and 062B. In the alternative, we are proposing BART to be an emission limit reflective of the installation and operation of DSI at 50 percent control for Unit 061B and SDA on 062B. We provide the reasoning for each determination in detail in the following paragraphs and solicit comment on both approaches.

In order to evaluate visibility benefits of control options for the Harrington units, we performed modeling using both CALPUFF and CAMx. As discussed in Section VII, and in more detail in our 2023 BART Modeling TSD, there are a number of differences between CAMx and CALPUFF with one of the concerns being CALPUFF's simpler chemistry mechanism that may underestimate the benefit of SO_2 reductions versus CAMx generated values using more state of the science chemistry.

a. Control Scenario 1: SDA on Unit 061B and Unit 062B

Table 16. CALPUFF Predicted Visibility Benefits of SDA on Both Harrington Units. *

Harrington	2016-2018 Baseline Impact	Modeled Benefit of SDA on Both Units	Cumulative 2016-2018

Class I Area	2016 dv	2017 dv	2018 dv	Cumulative 2016-2018 # of days with impacts ≥0.5 dv/ ≥1.0 dv	2016 dv	2017 dv	2018 dv	# of days with impacts ≥0.5 dv/ ≥1.0 dv
Carlsbad Caverns	0.39	0.41	0.56	16/5	0.24	0.27	0.31	1/1
Bandelier	0.17	0.12	0.14	2/0	0.12	0.09	0.11	0/0
Pecos	0.22	0.28	0.24	9/0	0.15	0.17	0.16	0/0
Salt Creek	0.49	0.59	0.54	27/3	0.23	0.39	0.32	2/0
Wheeler Peak	0.12	0.15	0.16	2/0	0.07	0.10	0.11	0/0
White Mountain	0.26	0.43	0.33	7/0	0.17	0.26	0.24	0/0
Wichita Mountains	0.54	0.45	0.58	24/8	0.35	0.23	0.33	3/0

* Benefit of control values are the decrease in deciview between baseline and the control scenario. Number of days is the number of days that are equal or greater than 0.5 and 1.0 dv after controls.

As in Section VII, we compared the visibility benefits (as predicted by CALPUFF) of the SDA control levels on both units to the baseline impacts in terms of percent reduction in visibility impacts. To make this comparison, we first calculated the average of the 98th percentile (8th highest value) for the three years modeled for each Class I area and the average for the seven Class I areas. For Harrington, Salt Creek was the highest impacted of the seven Class I areas and SDA control on both units compared to baseline resulted in a reduction of visibility impacts by 58 percent, from 0.54 dv to 0.23 dv. At the second highest impacted Class I area, Wichita Mountains, SDA on both units result in a reduction of visibility impacts by 58 percent, from 0.52 dv to 0.22 dv. SDA on both units also resulted in an average reduction of visibility impacts across the seven Class I areas combined of 61 percent. Using the CALPUFF modeling results from the baseline, we determined the total number of days when facility impacts were greater than 0.5 dv and 1.0 dv. Harrington had a total of 87 days with visibility impacts above 0.5 dv and

16 days above 1.0 dv at the seven Class I areas modeled with CALPUFF. In comparison, SDA on both units results in a large reduction in impacted days with only six days still above 0.5 dv and one day above 1.0 dv at the same seven Class I areas. In conclusion, the CALPUFF modeling results show that SDA on both units would provide notable visibility improvements.

Table 17. CAMx-Predicted Visibility Impact and Benefit of Controls for SDA

Harrington	**BASELINE**			**CONTROLLED**		
Class I area	**Impact (dv) on the Maximum Impact Day**	**Avg Impact (dv) for the Top 10 Days**	**Number of Days ≥0.5 / ≥1.0 dv**	**Visibility Improvement (dv) on the Maximum Impact Day**	**Avg Visibility Improvement (dv) for the Top 10 Days**	**Impacted Number of Days ≥0.5 / ≥1.0 dv**
Harrington Unit 061B						
White Mountain	1.43	0.48	3 / 1	0.96	0.35	0 / 0
Bandelier	0.83	0.28	1 / 0	0.64	0.23	0 / 0
Salt Creek	0.79	0.55	6 / 0	0.50	0.43	0 / 0
Cumulative (all Class I areas)	6.59	3.15	10 / 1	4.61	2.48	0 / 0
Harrington Unit 062B						
White Mountain	1.36	0.48	3 / 1	0.95	0.36	0 / 0
Bandelier	0.82	0.29	1 / 0	0.65	0.23	0 / 0
Salt Creek	0.79	0.56	6 / 0	0.52	0.45	0 / 0
Cumulative (all Class I areas)	6.55	3.17	10 / 1	4.79	2.56	0 / 0
Harrington Units 061B and 062B						
White Mountain	2.64	0.93	8 / 3	1.78	0.70	1 / 0

Bandelier	1.60	0.56	4 / 1	1.24	0.45	0 / 0
Salt Creek	1.52	1.08	13 / 6	0.97	0.86	1 / 0
Cumulative (all Class I areas)	12.77	6.23	44 / 10	9.08	5.00	2 / 0

The CAMx results reinforce that installation of SDA at the Harrington units would provide significant visibility benefits. CAMx modeling results indicate SDA on the individual Harrington units will eliminate all days impacted over 0.5 dv at all Class I areas. When considering the combined impacts of the two units, visibility benefits from SDA installed on both units predicts only one day to exceed the 0.5 dv threshold at each of the White Mountain and Salt Creek Class I areas. This is an overall (cumulative Class I areas) reduction from 44 days over 0.5 dv in the baseline to a total of only two days with SDA. The overall cumulative visibility improvement is 9.08 dv on the maximum impacted days and 5.0 dv improvement when considering the average of the top ten days across all 15 Class I areas.

For Harrington Unit 061B, the CAMx results show that SDA would eliminate all days impacted over 0.5 dv for that unit. On the maximum impacted day at White Mountain, SDA results in 0.96 dv improvement over baseline (1.43 dv), an additional 0.44 dv improvement over DSI at 50 percent control (from Table 12). On the maximum impacted day at Bandelier, SDA results in 0.64 dv improvement over the baseline (0.83 dv), an additional 0.3 dv improvement over DSI at 50 percent control. Furthermore, the CAMx results predict that the cumulative visibility benefit provided by SDA on just Unit 061B is 4.6 dv, with eight Class I areas seeing improvements of 0.25 dv or more.[330] SDA control on both units resulted in a reduction of maximum visibility impacts by 67 percent at White Mountain and an average reduction of

[330] Bandelier, Guadalupe Mountains, Carlsbad Caverns, Salt Creek, Upper Buffalo, White Mountain, Wheeler Peak, and Pecos visibility improvements with SDA on Harrington Unit 061B ranging from 0.25 dv to 0.96 dv.

maximum visibility impacts across all 15 Class I areas of 71 percent. This highlights that emissions and reductions from Harrington impact visibility conditions at several Class I areas. Visibility benefits for SDA on Unit 062B are very similar to Unit 061B.

Table 18. Cost Analysis Summary for Units 061B and 062B

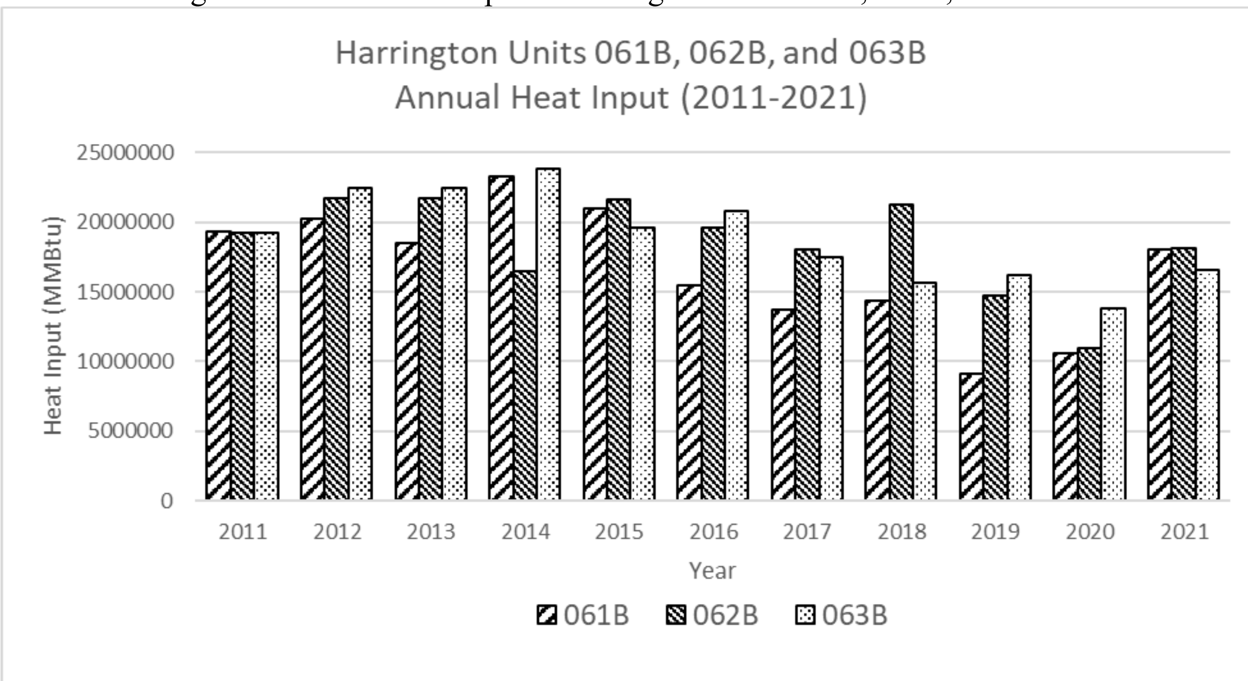
Facility	Control	SO_2 Reduction (tpy)	2020 Annualized Cost	2020 Cost-Effectiveness ($/ton)	2020 Incremental Cost-Effectiveness ($/ton)
Harrington 061B	DSI w/ESP- 50% control efficiency	1,892	$7,075,817	$3,740	
Harrington 061B	SDA	3,327	$21,967,236	$6,603	$10,377
Harrington 062B	DSI w/BGH- 50% control efficiency	2,703	$7,408,200	$2,742	
Harrington 062B	SDA	4,812	$23,369,564	$4,857	$7,568

A summary of our cost analyses from Section VII.B.3. are presented in Table 18. In our analysis, we find SDA to have a cost of $6,603/ton for Harrington Unit 061B, which is above the range for controls that we have previously found to be cost-effective. It is reasonable to expect that similar controls installed on units that are designed for similar capacity would result in similar tons reduced and cost effectiveness. Units 061B and 062B are designed to produce 360 MW of electricity but based on a review of heat input data from 2010 to 2021, differences in utilization or heat input have resulted in different estimates of tons reduced and cost effectiveness.[331] The resulting control cost effectiveness for Harrington Unit 061B ($6,603/ton)

[331] *See* “CAMD Heat Input Data for Harrington Station.xlsx” available in the docket for this action.

is higher than at the similarly designed and sized Unit 062B ($4,857/ton) because of a lower utilization rate.

Figure 1. Annual Heat Input at Harrington Units 061B, 062B, and 063B



As shown in Figure 1, the utilization rate of Unit 061B was much lower than Unit 062B during the 2016-2020 baseline period we evaluated for this proposed action. However, utilization rates both before and after the baseline period have been more consistent between the two units, and the utilization rate at Unit 061B has at times exceeded the annual utilization at Unit 062B. The difference in utilization during the baseline period used for the BART analysis results in a relatively smaller estimated reduction of SO_2 emissions (3,327 tons per year with SDA for Unit 061B compared to 4,812 tons per year reduced with SDA for Unit 062B) used to calculate the cost-effectiveness in $/ton removed.

Further examination of the historical heat input for these units shows that Unit 061B annual heat input for 2015 and for 2021 are higher than during the 2016-2020 period, and for both 2015 and 2021, heat input for Units 061B and 062B are similar. During Fall of 2016 through spring of 2017, Unit 061B was utilized less than the other two units at the facility.[332] This pattern continued for 2017/2018 and 2018/2019, resulting in lower overall heat input for the unit during those years. Starting in Fall of 2019, utilization of the BART units at the facility became roughly similar again, except during periods where a unit at the facility was down. We also note that July 2022 heat input for Unit 061B is higher than in any other single month from 2015-2022. These changes in utilization in the more recent period may suggest that the historical pattern of lower utilization of Unit 061B compared to Unit 062B that was observed in the majority of the 2016-2020 period may not continue in the future, which could result in more favorable (lower $/ton) cost-effectiveness for SDA and other controls at Harrington Unit 061B. Furthermore, because there are no enforceable limitations on utilization for these units, there is no assurance that Unit 061B will operate in the future at the lower utilization rates seen between 2016 and 2020.

We find that SDA on Units 061B and 062B provides significant visibility benefits. For Unit 062B we find SDA at $4,857/ton within the range we have previously found to be cost effective for BART. While above the range we have previously found to be cost effective, we still find SDA at $6,603/ton for Unit 061B to be reasonable based on the visibility benefits. Additionally, the estimated higher cost-effectiveness associated with SDA is driven by past lower utilization of Unit 061B during the baseline period. We propose and are taking comment on our determination that BART for Units 061B and 062B is an emission limit of 0.06 lb/MMBtu consistent with the installation and operation of SDA.

b. Control Scenario 2: DSI on Unit 061B and SDA on Unit 062B

[332] The Harrington facility has three EGUs. The third unit, Unit 063B, is not BART-eligible.

Because we recognize the cost effectiveness of SDA at Harrington Unit 061B is above a range of costs we have previously required for BART, we are proposing in the alternative to determine that BART is DSI at a control level of 50 percent, with a requirement to conduct a DSI performance evaluation.

Table 19. CALPUFF predicted visibility benefit of DSI (50 percent) on Harrington Unit 061B and SDA on Unit 062B.

Harrington	**2016-2018 Baseline**				**Benefit of DSI-50% at Unit 061B and SDA at Unit 062B**			**Cumulative 2016-2018 # of days with impacts ≥0.5 dv / ≥1.0 dv**
Class I Area	2016 dv	2017 dv	2018 dv	Cumulative # of days with impacts ≥0.5 dv/ ≥1.0 dv	2016 dv	2017 dv	2018 dv	
Carlsbad Caverns	0.39	0.41	0.56	16 / 5	0.18	0.21	0.23	5 / 1
Bandelier	0.17	0.12	0.14	2 / 0	0.09	0.06	0.08	0 / 0
Pecos	0.22	0.28	0.24	9 / 0	0.11	0.13	0.12	0 / 0
Salt Creek	0.49	0.59	0.54	27 / 3	0.16	0.30	0.25	11 / 1
Wheeler Peak	0.12	0.15	0.16	2 / 0	0.05	0.08	0.08	0 / 0
White Mountain	0.26	0.43	0.33	7 / 0	0.14	0.20	0.19	0 / 0
Wichita Mountains	0.54	0.45	0.58	24 / 8	0.27	0.20	0.25	8 / 0

* Benefit of control values are the decrease in deciview between baseline and the control scenario. Number of days is the number of days that are equal or greater than 0.5 and 1.0 dv after controls.

For Harrington, CALPUFF results show installation of DSI at a 50 percent control level on Unit 061B and SDA on Unit 062B resulted in a reduction of visibility impacts by 44 percent from the baseline at the highest impacted Class I area (Salt Creek) from 0.54 dv to 0.31 dv, and an average reduction of visibility impacts across seven Class I areas of 47 percent. For the 2016-2018 modeled years (baseline period), Harrington baseline had a total of 87 days with visibility impacts above 0.5 dv and 16 days above 1.0 dv at the seven Class I areas modeled with CALPUFF. DSI at 50 percent on Unit 061B and SDA on Unit 062B resulted in 24 days above 0.5 dv and two days above 1.0 dv. The incremental visibility benefit between DSI and SDA is larger with the CAMx modeling than with the CALPUFF modeling.[333]

Table 20. CAMx predicted visibility benefit of DSI (50 percent) on Unit 061B and SDA on Unit 062B

Harrington	**BASELINE**			**CONTROLLED**		
Class I area	**Impact (dv) on the Maximum Impact Day**	**Avg Impact (dv) for the Top 10 Days**	**Number of Days ≥0.5 / ≥1.0 dv**	**Visibility Improvement (dv) on the Maximum Impact Day**	**Avg Visibility Improvement (dv) for the Top 10 Days**	**Impacted Number of Days ≥0.5 / ≥1.0 dv**
Harrington Unit 061B with DSI (50 percent) control						
White Mountain	1.43	0.48	3 / 1	0.52	0.19	1 / 0
Bandelier	0.83	0.28	1 / 0	0.34	0.12	0 / 0
Salt Creek	0.79	0.55	6 / 0	0.26	0.23	1 / 0
Cumulative (all Class I areas)	6.59	3.15	10 / 1	2.56	1.34	2 / 0
Harrington Unit 062B with SDA control						
White Mountain	1.36	0.48	3 / 1	0.95	0.36	0 / 0
Bandelier	0.82	0.29	1 / 0	0.65	0.23	0 / 0
Salt Creek	0.79	0.56	6 / 0	0.52	0.45	0 / 0
Cumulative (all Class I areas)	6.55	3.17	10 / 1	4.79	2.56	0 / 0
Harrington Unit 061B with DSI (50 percent) and 062B with SDA controls						

333 *See* the 2023 BART Modeling TSD for detailed discussion of differences between CAMx and CALPUFF models and modeling results.

White Mountain	2.64	0.93	8 / 3	1.34*	0.54*	1 / 1**
Bandelier	1.60	0.56	4 / 1	0.94*	0.34*	1 / 0**
Salt Creek	1.52	1.08	13 / 6	0.73*	0.66*	3 / 0**
Cumulative (all Class I areas)	12.77	6.23	44 / 10	7.03*	3.86*	5 / 1**

*We did not model this combination (50 percent DSI on 061B and SDA on 062B) directly, so we estimated these values by subtracting the difference between the 50 percent DSI (Low Control) and SDA for 061B improvement values from the combined units SDA-only values in the previous table.
**Again, we did not model this combination directly, so we estimated the number of days based on the High (SDA) and Low (50 percent DSI) control number of days.

The CAMx results for Harrington for this second control scenario show that White Mountain was the most impacted of the 15 Class I areas, the same as in the first control scenario, which had SDA on both units. From Table 17 of the first control scenario, we calculate that SDA control on both units compared to baseline resulted in a reduction of visibility impacts at White Mountain by 67 percent and an average reduction of visibility impacts across the 15 Class I areas of 71 percent; whereas, from Table 20 we calculate that the 50% DSI on Unit 061B and SDA on Unit 062B compared to the baseline resulted in a reduction of visibility impacts at White Mountain by 51 percent and an average reduction of visibility impacts across the 15 Class I areas of 55 percent.

For Unit 061B, by itself, DSI at 50 percent control results in visibility benefits approximately one half of those achieved through SDA. On the maximum impacted day at White Mountain, DSI at 50 percent on Unit 061B results in 0.52 dv improvement compared to 0.96 dv with SDA on that unit; at Bandelier, DSI at 50 percent results in 0.34 dv improvement compared to 0.64 dv with SDA on that unit. The cumulative visibility benefit across all Class I areas on the maximum impacted days for Unit 61B with DSI at 50 percent is 2.56 dv compared to 4.61 dv with SDA. For the average of the top 10 most impacted days, SDA provides for a 0.43 dv benefit at Salt Creek compared to 0.23 dv for DSI at 50 percent control, and SDA provides for 0.35 dv benefit at White Mountain compared to 0.19 dv for DSI at 50 percent control – almost twice the improvement with SDA over DSI at 50% on Unit 061B.

When considering the combined benefits of DSI for Unit 061B and SDA for Unit 062B, the visibility improvement at White Mountain Class I area is estimated to be more than 1.3 (1.78 minus 0.44) dv on the highest impact day, while the average of the top 10 most impacted days visibility improvement is approximately 0.6 (0.86 minus 0.20) dv at Salt Creek. Overall, for the visibility improvement at the cumulative Class I areas from the Harrington facility, CAMx predicts an average improvement of almost 4.0 (5.00 minus 1.14) dv across all the Class I areas evaluated on the top 10 days and an improvement on the maximum impacted days of approximately 7.0 (9.08 minus 2.05) dv with SDA controls on Unit 062B and DSI at 50 percent on Unit 061B. Thus, we find that SDA on Unit 062B and DSI at 50 percent control on Unit 061B results in a significant reduction in visibility impacts from these units and that the benefits are spread across a number of Class I areas in New Mexico, Texas, and Oklahoma. As previously discussed, SDA on both units provides an additional cumulative visibility benefit (the difference between DSI at 50 percent control and SDA on Unit 061B) on the average of the top 10 days from the Harrington facility of 1.14 dv across all the Class I areas evaluated and an additional improvement on the maximum impacted days of 2.05 dv. However, DSI at 50 percent control for Harrington is more cost-effective ($2,742/ton for Unit 062B and $3,740/ton for Unit 061B) than SDA ($4,857/ton for Unit 062B and $6,603/ton for Unit 061B) and is well within the range of what we have previously found to be acceptable in other BART actions. For Harrington Unit 062B, we consider SDA to also be cost-effective and within the range of what we have previously found to be acceptable in other BART actions. As discussed earlier, the cost of SDA at Unit 061B is above the range we have previously found to be cost-effective, and the incremental cost-effectiveness of SDA (going from DSI at 50 percent control efficiency to SDA) is $10,377, which we consider to be relatively high. The cost of SDA at Unit 061B is relatively high, but we still find SDA to be reasonable based on the important visibility benefits of SDA on this unit. However, given the relatively high cost of SDA at Unit 061B, we propose in the alternative that BART for this unit is based on DSI. While the visibility benefits of DSI are approximately half those from SDA on Unit 061B using the CAMx results, installation of DSI is significantly less costly than SDA. Therefore, we are proposing in the alternative that BART for Unit 061B is 0.27 lb/MMBtu based on DSI at 50 percent, with a compliance period of no later than two (2) years from the effective date of the final rule.[334]

We believe Unit 061B is likely capable of achieving an SO_2 emission limit of 0.27 lb/MMBtu with DSI but are not certain whether the unit could achieve a lower emission limit on a 30 BOD or what the potential impacts to PM emissions could be at higher injections rates necessary for higher control efficiencies using the existing ESP. We evaluated DSI at a 50 percent control level as a conservative representative of what DSI can achieve on average. Because the control efficiency of DSI is dependent on several operational variables, we also propose to require a performance evaluation (as provided for in Section IX.A.3) to determine the maximum control efficiency of DSI for Harrington Unit 061B specifically along with an estimate of the cost to operate DSI at this control level.[335] Based on available information, on a unit-

[334] The proposed regulatory language for this rulemaking only covers our first proposed approach (SDA on Harrington Units 061B and 062B). If the EPA finalizes an action consistent with our alternative proposed approach (DSI at 50% control on Unit 061B and SDA on Unit 062B), we will revise the regulatory language accordingly.
[335] The purpose of the DSI performance evaluation is to determine the lowest SO_2 emission rate Unit 061B would be able to sustainably achieve on a 30 BOD with DSI under three different scenarios for particulate removal ((1) using the existing ESP; (2) with a new ESP installation; and (3) with a new fabric filter installation) and to determine how compliance with such an emission rate would impact our cost estimates for DSI. The proposed DSI performance evaluation requirements are discussed in greater detail in Section IX.A.3.

specific basis, using sodium-based sorbents, we believe DSI could potentially achieve up to 80 percent or higher SO_2 control, even with an ESP. However, as noted earlier, because of unit-specific uncertainty we are proposing an emissions limit of 0.27 lb/MMBtu based on DSI at 50 percent. If a DSI performance evaluation finds that Unit 061B can meet a lower rate, we will propose to adjust this limit in a future notice to reflect the maximum control efficiency that the unit can consistently meet. As discussed in Sections VII.B.2.a and VII.B.3.a, we are also soliciting comments on the range and maximum control efficiency that can be achieved with DSI at the evaluated units, including Harrington Unit 061B, and estimates of the range of associated costs. We are especially interested in comments on any site-specific DSI testing for Unit 061B to determine the range and maximum control efficiency that can be achieved with DSI at the unit. Any data to support the control efficiency range, maximum control efficiency, and cost of DSI for the unit should be submitted along with those comments. We will further consider DSI site-specific information provided to us during the public comment period in our final decision and potentially re-evaluate DSI for this particular unit.

c. Option to Convert to Natural Gas

Additionally, we recognize that Xcel Energy has announced its intent to convert Harrington Station to natural gas by January 1, 2025. We understand this has been formalized further in an Agreed Order with TCEQ,[336] a PSD permit revision,[337] and approval from the Texas Public Utility Commission (PUC).[338] The BART Guidelines state in situations where a future operating parameter will differ from past or current practices, and if such future operating

[336] In the Matter of an Agreed Order Concerning Southwestern Public Service Company, dba cel Energy, Harrington Station Power Plant, TCEQ Docket No. 2020-0982-MIS (Adopted Oct. 21, 2020). A copy of the Order is available in the docket for this action.
[337] *See* Harrington's revised PSD permits (NSR1529 and NSR1388) located in the docket for this action.
[338] *See* the Texas PUC Order, Docket No. 52485-201, located in the docket for this action.

parameters will have a deciding effect in the BART determination, then the future operating parameters need to be made federally enforceable and permanent in order to consider them in the BART determination.[339] Thus, we are providing Xcel Energy the option to make this conversion to natural gas a permanent and federally enforceable commitment by incorporating it into this FIP. We are proposing that should Xcel Energy agree to these future operating parameters (i.e. operating as a natural gas source no later than January 1, 2025), then for purposes of this analysis we will consider Harrington to be a natural gas source. We noted earlier that for natural gas units, there are no practical add-on controls to consider for setting a more stringent SO_2 BART emission limit. Therefore, under this option, we propose that BART for both Harrington units is the burning of pipeline natural gas, as defined at 40 CFR 72.2.[340] Because the conversion to natural gas no later than January 1, 2025, would occur before the deadline to comply with a BART emission limit reflective of the installation of DSI or scrubbers, there is no need to evaluate whether an interim SO_2 emission limit is necessary prior to the conversion to natural gas. Additionally, the visibility benefits of a conversion to natural gas would be greater than with the limits we are proposing based on either SDA or DSI. We are interested in comments on this option and specifically invite Harrington to provide comments as to their interest in this option.

3. Welsh Unit 1

In reviewing the modeling results for Welsh Unit 1, we conclude that the installation of a wet FGD or SDA will provide significant visibility benefits. As discussed in Section VII.A.1, we

[339] 70 FR at 39167.

[340] "Pipeline natural gas" means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions, and which is provided by a supplier through a pipeline. Pipeline natural gas contains 0.5 grains or less of total sulfur per 100 standard cubic feet. This is equivalent to an SO_2 emission rate of 0.0006 lb/MMBtu. Additionally, pipeline natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 Btu per standard cubic foot. 40 CFR 72.2.

modeled Welsh Unit 1 with both CALPUFF and CAMx. The visibility benefits for Welsh are summarized in Tables 21 and 22.

Table 21. CALPUFF-predicted Wet FGD and SDA Visibility Benefits at Welsh Unit 1 *

Class I Area	**2016-18 Baseline**				**High Control Scenarios (WFGD/SDA)**				
					Visibility Benefit at Class I Area (dv) from Baseline (WFGD/SDA)			Cumulative 2016-18 # of Days with impacts ≥0.5 dv/ ≥1.0 dv	
	2016 dv	2017 dv	2018 dv	Cumulative 2016-2018 # of Days with impacts ≥0.5 / ≥1.0 dv	2016 dv	2017 dv	2018 dv	WFGD	SDA
Caney Creek	0.70	0.94	0.96	77/13	0.28/0.27	0.37/0.35	0.53/0.53	18/1	18/1
Upper Buffalo	0.36	0.49	0.60	16/0	0.25/0.24	0.33/0.32	0.42/0.40	0/0	1/0
Wichita Mountains	0.25	0.35	0.24	3/0	0.17/0.16	0.28/0.26	0.16/0.16	0/0	1/0

* Benefit of control values are the decrease in deciview between baseline and the control scenario. Number of days is the number of days that are equal or greater than 0.5 and 1.0 dv after controls.

The Welsh facility is within 450 km of three Class I areas (Caney Creek, Wichita Mountains, and Upper Buffalo), and therefore, within the range that the CALPUFF model has been used for assessing visibility impacts in BART analyses. CALPUFF results for Welsh indicate that installation of wet FGD or SDA resulted in a reduction of visibility impacts by 45 percent (0.39 dv average visibility benefit) and 44 percent (0.38 dv average visibility benefit), respectively from the baseline (0.86 dv) at the highest impacted Class I area (Caney Creek), and an average reduction of visibility impacts across the three Class I areas of 57 percent and 55 percent respectively.

Using three years (2016-2018) CALPUFF modeling results, we assessed the annual number of days when the facility impacts were greater than the 0.5 dv and 1.0 dv threshold at each of the Class I areas and then summed this value for all Class I areas to determine the total number of days in the 2016-2018 modeled period where visibility impacts were above 0.5 dv and 1.0 dv. These results indicate that the installation of wet FGD or SDA will eliminate 78 days (81 percent decrease) and 76 days (79 percent decrease) respectively where visibility is greater than 0.5 dv and 12 days (92 percent decrease) where visibility is greater than 1.0 dv over the three modeled years for these three Class I areas. Comparing the CALPUFF modeled improvement with the installation of wet FGD versus SDA on Unit 1 indicates the visibility benefits are very similar (within 1.3-5.4 percent of each other).

Table 22. CAMx-predicted Wet FGD *(SDA)* Visibility Benefits at Welsh Unit 1

Welsh Unit 1	**BASELINE**			**CONTROLLED**		
Class I area	**Impact (dv) on the Maximum Impact Day**	**Avg Impact (dv) for the Top 10 Days**	**Number of Days ≥0.5 / ≥1.0 dv**	**Visibility Improvement (dv) on the Maximum Impact Day***	**Avg Visibility Improvement (dv) for the Top 10 Days***	**Impacted Number of Days ≥0.5 / ≥1.0 dv**
Caney Creek	1.58	1.11	27 / 6	1.08 *(1.02)*	0.83 *(0.79)*	0 / 0
Wichita Mountains	1.54	0.71	6 / 2	1.34 *(1.29)*	0.60 *(0.57)*	0 / 0
Upper Buffalo	1.12	0.68	8 / 1	0.83 *(0.79)*	0.53 *(0.50)*	0 / 0
Cumulative (all Class I areas)	6.67	3.97	46 / 9	5.27	3.21	0 / 0

* Secondary values in parentheses indicate estimated visibility benefits for SDA

Table 22 displays the visibility benefits predicted by CAMx with wet FGD control levels applied to Welsh Unit 1. We also present the estimated benefits of SDA (shown in parentheses).

Since SDA is slightly less effective at reducing SO_2 emissions than wet FGD, the comparative results between SDA and wet FGD are consistent with the difference in control efficacy, with a difference between wet FGD and SDA on the maximum impacted day of 0.06 dv at Caney Creek and 0.05 dv at Wichita Mountains and an average top 10 days difference of 0.03-0.04 dv at each of the top three Class I areas.

CAMx modeling results indicate that wet FGD on Welsh Unit 1 will eliminate all days impacted by the unit over 0.5 dv at all Class I areas, from 46 days in the baseline to zero with wet FGD, and SDA controls eliminate all but one day with impacts over 0.5 dv. At the most impacted Class I areas, wet FGD control results in visibility improvements of up to 1.35 dv on the maximum impacted day at Wichita Mountains and 1.29 dv with SDA control compared to the baseline maximum impact of 1.54 dv. Similarly, wet FGD control results in visibility improvements of up to 1.08 dv on the maximum impacted day at Caney Creek and 1.02 dv with SDA control compared to the baseline maximum impact of 1.58 dv. For the average of the top 10 most impacted days, wet FGD control results in 0.82 dv, while SDA results in 0.79 dv visibility improvements at Caney Creek (baseline impact 1.11 dv). For the average of the top 10 most impacted days, wet FGD control results in 0.60 dv, while SDA results in 0.57 dv visibility improvements at Wichita Mountains (baseline impact 0.71 dv).

Overall, there is a cumulative improvement to the average of the top 10 days of approximately 3.2 dv with wet FGD across all impacted Class I areas and approximately 5.3 dv cumulative improvement on the maximum impacted day. The 2023 BART Modeling TSD shows that DSI control achieved approximately 39 percent average improvement in visibility, while wet FGD averaged 79 percent overall visibility improvement. At Caney Creek, DSI results in improvement on the maximum impacted day of 0.48 dv compared to 1.08 dv for wet FGD and

1.02 dv for SDA. At Wichita Mountains, DSI results in improvement on the maximum impacted day of 0.69 dv compared to 1.35 dv for wet FGD and 1.29 dv for SDA. At Caney Creek, the baseline had 27 days over 0.5 dv and 6 days over 1.0 dv, but with DSI these number of days were reduced to 8 and 1, respectively, and further reduced with wet FGD to zero days over 0.5 dv and zero days over 1.0 dv. At Wichita Mountains, the baseline had 6 days over 0.5 dv and 2 days over 1.0 dv, but with DSI these number of days were reduced to 2 and zero, respectively, and further reduced with wet FGD to zero days over 0.5 dv and zero days over 1.0 dv.

We conclude that both SDA and wet FGD are cost-effective at $4,370/ton and $4,497/ton (respectively) and remain within a range that we have previously found to be acceptable. Wet FGD is less cost-effective than SDA and as discussed in the preceding paragraphs, it would have only a slight additional visibility benefit over SDA. As discussed earlier, in weighing the factors between SDA and wet FGD, we determined the additional visibility benefits did not outweigh the additional cost, water requirements, and wastewater treatment requirements associated with wet FGD. DSI at 50 percent control is more cost-effective but results in much less visibility benefit. We consider the significant visibility benefits that will result from the installation of SDA at Welsh Unit 1 to justify the cost, and therefore, we propose that SO_2 BART for Welsh Unit 1 should be based on the installation of SDA at an emission limit of 0.06 lb/MMBtu based on a 30 BOD.

We recognize that at $4,370/ton, the cost of SDA for Welsh Unit 1 is in the upper range of cost-effectiveness of controls found to be acceptable in other BART actions nationwide. Nevertheless, we consider it to be cost-effective and provides for significant visibility benefit. Since BART is defined as an emission limitation,[341] sources have the flexibility to decide what

[341] See 40 C.F.R. Part 51, Appendix Y – Guidelines For BART Determinations Under the Regional Haze Rule, section IV.A.

controls to install and implement so long as they comply with the BART emission limitations and associated requirements that are promulgated. As discussed in Section VIII.A, based on available DSI cost information, some EGUs with an installed baghouse may be able to achieve 90+ percent SO_2 control efficiency using DSI with sodium-based sorbents. Therefore, Welsh Unit 1 could potentially comply with our proposed SO_2 emission limit of 0.06 lb/MMBtu with DSI operated at a high SO_2 control level, but this would need to be confirmed with site-specific performance testing. If the unit is capable of meeting this SO_2 emission limit with DSI, this control technology is likely to be even more cost-effective than SDA.

As discussed in Sections VII.B.2.a and VII.B.3.a, we also invite comments on the range and maximum control efficiency that can be achieved with DSI at Welsh Unit 1 and estimates of the range of associated costs. We are especially interested in any site-specific DSI testing for Welsh Unit 1 to determine the range and maximum control efficiency that can be achieved with DSI at this unit. Any data to support the control efficiency range, maximum control efficiency, and cost of DSI for the unit should be submitted along with those comments. We will further consider site-specific information provided to us during the public comment period in making our final decision on SO_2 BART and potentially re-evaluate DSI for this particular unit.

4. W. A. Parish Units WAP4, WAP5 & WAP6

W. A. Parish Unit WAP4 is the only gas-fired unit we determined to be subject to BART. Gas-fired EGUs have inherently low SO_2 emissions and there are no known SO_2 controls that can be evaluated. While we must assign SO_2 BART determinations to the gas-fired unit, there are no practical add-on controls to consider for setting a more stringent BART emission limit. As explained earlier in Section VII.B.1.c, the BART 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. As there are no appropriate add-on controls and the status quo reflects the most stringent control level, we are proposing that SO_2 BART for W. A. Parish Unit WAP4 is to limit fuel to pipeline natural gas, as defined at 40 CFR 72.2.[342]

In evaluating W. A. Parish Units WAP5 and WAP6, we conclude that the installation of wet FGD or SDA will result in significant visibility benefits. We summarize some of these visibility benefits in Table 23.

Table 23. CAMx predicted visibility benefit of Wet FGD *(SDA)* at W. A. Parish

W. A. Parish	**BASELINE**			**CONTROLLED**		
Class I area	**Impact (dv) on the Maximum Impact Day**	**Avg Impact (dv) for the Top 10 Days**	**Number of Days ≥0.5 / ≥1.0 dv**	**Visibility Improvement (dv) on the Maximum Impact Day***	**Avg Visibility Improvement (dv) for the Top 10 Days***	**Impacted Number of Days ≥0.5 / ≥1.0 dv**
W. A. Parish WAP5						
Wichita Mountains	2.01	0.83	12 / 1	1.86 *(1.80)*	0.77 *(0.75)*	0 / 0
Caney Creek	1.57	1.09	36 / 6	1.38 *(1.36)*	0.97 *(0.94)*	0 / 0
Breton	1.08	0.52	4 / 1	0.94 *(0.92)*	0.47 *(0.45)*	0 / 0
Cumulative (all Class I areas)	8.82	5.18	86 / 10	7.93	4.71	0 / 0
W. A. Parish WAP6						
Wichita Mountains	2.24	0.93	15 / 1	2.07 *(2.01)*	0.86 *(0.84)*	0 / 0
Caney Creek	1.75	1.22	47 / 9	1.52 *(1.50)*	1.08 *(1.05)*	0 / 0
Breton	1.21	0.58	4 / 2	1.05 *(1.02)*	0.52 *(0.50)*	0 / 0
Cumulative (all Class I areas)	9.86	5.80	119 / 15	8.81	5.27	0 / 0

[342] As provided for in 40 CFR 72.2, pipeline natural gas contains 0.5 grains or less of total sulfur per 100 standard cubic feet. This is equivalent to an SO_2 emission rate of 0.0006 lb/MMBtu.

W. A. Parish WAP5 and WAP6						
Wichita Mountains	3.97	1.71	35 / 12	3.61	1.56	0 / 0
Caney Creek	3.13	2.22	86 / 38	2.59	1.91	1 / 0
Breton	2.21	1.08	12 / 4	1.89	0.96	0 / 0
Cumulative (all Class I areas)	17.96	10.72	269 / 91	15.66	9.56	1 / 0

* Secondary values in parentheses indicate estimated visibility benefits for SDA

Table 23 displays the visibility benefits predicted by CAMx modeling with wet FGD control levels applied to Units WAP5 and WAP6. We also present the estimated benefits of SDA (shown in parentheses) for each unit individually. Since SDA is slightly less effective at reducing SO_2 emissions than wet FGD, the comparative results between SDA and wet FGD are consistent with the difference in control efficacy, with a maximum difference between wet FGD and SDA on the maximum impacted day of 0.06 dv at Wichita Mountains for each unit (0.02-0.03 dv for Caney Creek and Breton) and an average top 10 days difference of 0.03 dv at Caney Creek (0.02 dv at Wichita Mountains and Breton) for each unit, with SDA always showing marginally less improvement from the baseline. These values indicate that SDA per unit results in approximately 2-4 percent less benefit than wet FGD on a per unit basis.

CAMx modeling results indicate that wet FGD installed on each of Units WAP5 and WAP6 will eliminate all days impacted by each unit over 0.5 dv at all Class I areas, and our estimates for SDA control also show no days over 0.5 dv at any Class I areas. When considering the combined impacts from all three units taken together with wet FGD on WAP5 and WAP6, the CAMx results predict one day to exceed the 0.5 dv threshold (at Caney Creek).[343] We would

[343] W. A. Parish Unit WAP4 is a gas-fired unit for which we are locking in the requirement to burn pipeline quality natural gas.

expect similar results in looking at SDA for Units WAP5 and WAP6 as the visibility differences for SDA and wet FGD are small. Overall, there is a cumulative reduction from 269 days over 0.5 dv in the baseline to a total of just one day over the threshold with wet FGD across all impacted Class I areas.

Installation of wet FGD on both units results in 3.61 dv improvement (91 percent reduction of 3.97 dv baseline) on the maximum impact day at Wichita Mountains and a 1.56 dv improvement (91 percent reduction of 1.71 dv baseline) on the top 10 average days at Wichita Mountains. Installation of wet FGD on both units results in 2.59 dv improvement (83 percent reduction of 3.13 dv baseline) on the maximum impact day at Caney Creek and a 1.91 dv improvement (86 percent reduction of 2.22 dv baseline) on the top 10 average days at Caney Creek. SDA visibility benefits on a unit basis result in 95 percent or more of the visibility benefit of wet FGD on a unit basis. At the most impacted Class I areas, either wet FGD or SDA on each unit will each result in visibility improvements of more than 1.8 dv per unit at Wichita Mountains, and the top 10 days average visibility improvement for the individual units are more than 0.9 dv at Caney Creek for each unit with wet FGD or SDA. Across all impacted Class I areas, the top 10 days average improvement from all three units combined is predicted to be approximately 9.5 dv, or approximately 89 percent reduction in visibility impairment due to wet FGD controls or SDA. As provided in Section VII.B.4, DSI operated at 50 percent control ("low control scenario") results in 43 percent visibility improvement for the overall three units, whereas wet FGD visibility benefits result in 87 percent improvement at the most impacted Class I areas for the three units and the cumulative 15 Class I areas included in the modeling.

We conclude that both SDA and wet FGD are cost-effective at $3,044/ton and $3,074/ton (respectively) for Unit WAP5 and $2,651/ton and $2,717/ton (respectively) for Unit WAP6 and remain well within a range that we have previously found to be acceptable. While DSI at 50 percent control is more cost-effective at $2,262/ton for Unit WAP5 and $2,244/ton for Unit WAP6, it results in less visibility benefit. The incremental cost-effectiveness of SDA (going from DSI at 50 percent control efficiency to SDA) is $4,006/ton for Unit WAP5 and $3,155/ton for Unit WAP6, which we consider to be reasonable. Thus, we conclude that the resulting visibility benefit offered by scrubbers outweighs the possible advantage DSI at 50 percent control may hold in cost-effectiveness.

Wet FGD is slightly less cost-effective than SDA and we estimate based on scaling of our CAMx modeling results that it would have only a slight additional visibility benefit over SDA. As discussed earlier, in weighing the factors between SDA and wet FGD, we determined the additional visibility benefits did not outweigh the additional cost, water requirements and wastewater treatment requirements associated with wet FGD. We consider the cost of SDA at the two 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 WAP5 and WAP6 should be based on the installation of SDA at an emission limit of 0.06 lb/MMBtu based on a 30 BOD.

B. SO_2 BART for Coal-fired Units with Existing Scrubbers

1. Martin Lake Units 1, 2, and 3

The BART Guidelines state that underperforming scrubber systems should be evaluated for upgrades.[344] 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 at Martin Lake. These units were modeled with both CALPUFF and CAMx. We summarize some of these

[344] 70 FR 39171 (July 6, 2005).

visibility benefits from upgrading Martin Lake's existing scrubbers in Tables 24 and 25.

Table 24. CALPUFF-predicted Scrubber Upgrade Visibility Benefits at Martin Lake.

	2016-18 Baseline Impacts				**Scrubber Upgrades**			
					Visibility Benefit at Class I Area (dv) from Baseline			Cumulative 2016-2018 # of Days with impacts ≥0.5 dv/ ≥1.0 dv
Class I Area	2016 dv	2017 dv	2018 dv	Cumulative 2016-2018 # of Days with impacts ≥0.5 dv/ ≥1.0 dv	2016 dv	2017 dv	2018 dv	
Caney Creek	3.28	3.60	3.35	338/215	2.12	2.36	2.16	133/44
Upper Buffalo	2.12	2.54	2.27	212/115	1.58	1.90	1.72	33/8
Wichita Mountains	1.45	1.07	1.15	79/36	1.21	0.89	0.91	5/2
Cumulative	6.84	7.21	6.78	629/366	4.90	5.15	4.79	171/54

In evaluating Martin Lake, there are three Class I areas (Caney Creek, Upper Buffalo, and Wichita Mountains) within the typical 450 km range that CALPUFF has been used for assessing visibility impacts. The modeled scrubber upgrades result in large visibility improvements of over 2.2 dv at Caney Creek and 1.7 dv at Upper Buffalo. Visibility benefits at Wichita Mountains also exceed 1.0 dv. CALPUFF results for Martin Lake indicate that upgrading the scrubbers resulted in a reduction of visibility impacts by 65 percent from the baseline at the highest impacted Class I area (Caney Creek), and an average reduction of visibility impacts at the three Class I areas of 71 percent. Using the three years (2016-2018) of CALPUFF modeling results, we assessed the annual average number of days, averaged across the three years, when the facility impacts were greater than 0.5 dv at each Class I area; we also looked at the cumulative number of days summed across the three years at all the Class I areas (three in this case). The reduction in the number of days (annual average) was calculated using the cumulative value of the number of days (three-year total) over the 0.5 dv threshold across the three Class I areas for the baseline scenario minus the cumulative number of days (three-year total) over the threshold for the control scenario. For the three Class I areas, 2016-2018 CALPUFF modeling results indicate that upgraded scrubbers on the three units will eliminate 152 days annually (3-year average), or 458 days cumulatively across the 3 years, when the facility has impacts greater than 0.5 dv in the baseline. The same analysis for the 1.0 dv threshold, as reported in Table 24, has 104 days (312 days total) reduced on annual average. CALPUFF modeling results indicate large improvements at the individual Class I areas and the cumulative improvement of almost 5 dv; these scrubber upgrades markedly improve the overall cumulative predicted visibility by approximately 71 percent from the baseline.

Table 25 includes each affected Martin Lake unit and the combined facility along with the resulting CAMx-modeled visibility benefits from upgrading Martin Lake's existing scrubbers.

Table 25. CAMx predicted visibility benefit of Scrubber Upgrades for Martin Lake

Martin Lake	BASELINE			CONTROLLED		
Class I area	**Impact (dv) on the Maximum Impact Day**	**Avg Impact (dv) for the Top 10 Days**	**Number of Days ≥0.5 / ≥1.0 dv**	**Visibility Improvement (dv) on the Maximum Impact Day**	**Avg Visibility Improvement (dv) for the Top 10 Days**	**Impacted Number of Days ≥0.5 / ≥1.0 dv**
Martin Lake Unit 1						
Caney Creek	2.60	1.98	74/ 22	2.00	1.56	2 / 0
Wichita Mountains	2.08	1.01	17 / 3	1.76	0.85	0 / 0
Upper Buffalo	1.93	1.39	48 / 8	1.66	1.18	0 / 0
Cumulative (all Class I areas)	12.39	7.90	197 / 38	10.36	6.64	2 / 0
Martin Lake Unit 2						
Caney Creek	2.54	1.94	72 / 22	1.94	1.52	2 / 0
Wichita Mountains	2.03	0.99	17 / 3	1.71	0.82	0 / 0
Upper Buffalo	1.89	1.36	44 / 8	1.62	1.14	0 / 0
Cumulative (all Class I areas)	12.09	7.71	188 / 38	10.06	6.44	2 / 0
Martin Lake Unit 3						
Caney Creek	2.81	2.14	85 / 24	2.23	1.73	2 / 0
Wichita Mountains	2.24	1.09	18 / 3	1.93	0.93	0 / 0
Upper Buffalo	2.09	1.51	51 / 12	1.84	1.30	0 / 0
Cumulative (all Class I areas)	13.44	8.59	223 / 48	11.45	7.34	2 / 0
Martin Lake Units 1, 2, and 3						
Caney Creek	6.69	5.27	150 / 101	5.00	4.07	32 / 7
Wichita Mountains	5.49	2.83	51 / 27	4.57	2.35	3 / 0

Upper Buffalo	5.16	3.83	111 / 70	4.39	3.21	7 / 0
Cumulative (all Class I areas)	33.79	22.16	521 / 301	27.91	18.44	47 / 7

Table 25 shows that the Martin Lake units individually cause or contribute to visibility impairment at Wichita Mountains, Caney Creek, and Upper Buffalo on a large number of days. CAMx predicts baseline impacts for these combined three units to be more than the 0.5 dv visibility threshold 150 days of the year at Caney Creek, 111 days of the year at Upper Buffalo, 51 days of the year at Wichita Mountains, and in total for 209 days per year for the other 12 Class I areas modeled. The average visibility impact across the top 10 days for the combined units is more than 5.2 dv at Caney Creek and more than 3.8 dv at Upper Buffalo. CAMx modeling results indicate that upgrades to Martin Lake's wet FGD scrubbers to 95 percent control efficiency installed on each of the units will eliminate all but two days impacted by each individual unit over 0.5 dv at all Class I areas. When considering the combined impacts from all three units, the modeling results show an overall (across all impacted Class I areas) reduction from 521 days over 0.5 dv in the baseline to a total of 47 days over the threshold after the scrubber upgrades are installed, for an overall reduction of more than 90 percent in the number of days over the threshold. With the modeled scrubber upgrades, the number of days impacted over 1.0 dv are reduced from 101 days to 7 days at Caney Creek. Days over the 1.0 dv threshold at all other Class I areas are eliminated, decreasing from 200 in the baseline to zero with the scrubber upgrades. At the most impacted Class I Areas, the scrubber upgrades on each unit will each result in visibility improvements of approximately 2.0 dv on the most impacted days at Caney Creek, and the top 10 days average visibility improvement for the individual units is more than 1.5 dv at Caney Creek. Across all 15 Class I areas, the top 10 days average impact from all three units combined dropped from baseline of 22.2 dv to 3.7 dv after control upgrades, for an overall cumulative improvement of approximately 83 percent reduction due to improved scrubber efficiency. Similarly, across all 15 Class I areas, the maximum daily impact from scrubber upgrades results in a visibility improvement of 27.91 dv compared to the 33.79 dv baseline total, which is a reduction of 83 percent.

As we state elsewhere in this proposal, we estimate scrubber upgrades at the Martin Lake units to be very cost-effective and less than $1,200/ton. We conclude that these 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 SO_2 BART for each Martin Lake unit should be to upgrade the wet FGD scrubbers to a control efficiency of 95 percent, with an emission limit of 0.08 lb/MMBtu on a 30 BOD basis. This cost analysis, the reasons set forth in previous sections regarding the overall SO_2 emissions impact of these units, and the modeled benefits, support this proposed BART determination.

2. Fayette Units 1 and 2

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 Boiler Operating Day (BOD) average below 0.04 lb/MMBtu for years at a time.[345] As discussed in Section VII.B.2.a, retrofit wet FGDs should be evaluated at 98 percent control or no less than 0.04 lb/MMBtu. Table 26 shows the visibility impacts for the baseline emissions, the current permitted emission limit (which is greater than the baseline emission rate), and an emission limit of 0.04 lb/MMBtu (which is representative of controlled emissions with wet FGD).

[345] See our 2023 BART FIP TSD for additional information and graphs of this data.

Table 26. CAMx-predicted Visibility Impacts of Baseline, Permit Limits, and Wet FGD Limit of 0.04 lb/MMBtu for Fayette Units 1 and 2.

Fayette Units 1 and 2	**2016 Baseline Impacts**		**Permitted Limit (0.2 lb/MMBtu)**		**Wet FGD (0.04 lb/MMBtu)**	
Class I area	**Impact at Class I area (dv)**	**# days ≥0.5 dv / ≥1.0 dv**	**Impact at Class I area (dv)**	**# days >0.5 dv / # of days >1.0 dv**	**Impact at Class I area (dv)**	**# days ≥0.5 dv / ≥1.0 dv**
Caney Creek	0.52	1 / 0	1.04	11 / 1	0.52	1 / 0
Wichita Mountains	0.34	0 / 0	1.02	3 / 1	0.31	0 / 0
Upper Buffalo	0.33	0 / 0	0.73	5 / 0	0.34	0 / 0
Cumulative (all 15 Class I areas)	2.24	1 / 0	5.31	21 / 2	2.12	1 / 0

Fayette modeling shows increased visibility impacts when modeling the existing permit limit (Title V permit level of 0.2 lb/MMBtu to meet NSPS UUUUU). At this higher permitted rate, the Fayette source would have visibility impacts greater than 1 dv at Caney Creek and Wichita Mountains. However, Fayette routinely emits at rates less than this permit limit. We also modeled wet FGD at 0.04 lb/MMBtu, which these units already consistently meet on a 30-day BOD basis. The results are very similar to baseline modeling results reflecting the maximum 24-hr emissions from 2016-2020, but did result in a slight overall benefit from baseline conditions. Therefore, we propose that additional scrubber upgrades for Fayette are not necessary and that Fayette Units 1 and 2 maintain a 30 BOD rolling average SO_2 emission rate of 0.04 lb/MMBtu. We believe that based on their demonstrated ability to maintain an emission rate below this value on a 30 BOD basis, these units can consistently achieve this emission level.

C. PM BART

As discussed in Section VI.B, we propose to disapprove the portion of the Texas Regional Haze SIP that sought to address the BART requirement for EGUs for PM. We present our analysis of the BART factors and the potential costs and visibility benefits of PM controls in

Section VII.B.5. All the coal-fired units are either currently fitted with a baghouse, an ESP and a polishing baghouse, or an ESP. As part of our BART determination, we propose to conclude that the cost of retrofitting the subject units (Harrington Unit 061B, Martin Lake Units, and Fayette Units) with a baghouse would be extremely high compared to the visibility benefit for any of the units currently fitted with an ESP. The BART Guidelines state it is permissible to rely on MACT standards for purposes of BART unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control. Because the costs of installing a baghouse would be extremely high, we propose that PM BART for the coal-fired units is an emission limit of 0.030 lb/MMBtu along with work practice standards. This limit is consistent with the MATS Rule, which establishes an emission standard of 0.030 lb/MMBtu filterable PM (as a surrogate for toxic non-mercury metals) as representing MACT for coal-fired EGUs.

For the gas-fired BART unit, W. A. Parish Unit WAP4, 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 are proposing that PM BART for W. A. Parish Unit WAP4 is to limit fuel to pipeline natural gas, as defined at 40 CFR 72.2.

IX. Proposed Action

A. Regional Haze

We are proposing to withdraw the Texas SO_2 Trading Program set forth in 40 CFR Part 97 Subpart FFFFF, which constitutes the FIP provisions the EPA previously promulgated to address SO_2 BART obligations for EGUs in Texas. In its place, we are proposing to promulgate a FIP as described in this notice and summarized in this section to address the SO_2 BART requirements for those BART-eligible sources participating in the Texas SO_2 Trading Program.

Additionally, as described in Section VI, we are proposing that our prior approval of the portion of the Texas Regional Haze SIP related to PM BART for EGUs was in error and are correcting that through disapproving that portion of the SIP and promulgating source specific BART requirements to address the deficiency. Our proposed FIP includes SO_2 and PM BART emission limits for 12 EGUs located at 6 different facilities.

1. SO_2 BART

We propose that SO_2 BART for the subject-to-BART units is the following SO_2 emission limits to be met on a 30 BOD period:

Table 27. Proposed SO_2 BART Emission Limits

	UNIT	PROPOSED SO_2 EMISSION LIMIT (LB/MMBTU)
Scrubber Upgrades	Martin Lake Unit 1	0.08
	Martin Lake Unit 2	0.08
	Martin Lake Unit 3	0.08
Emission Limit as BART	Fayette Unit 1	0.04
	Fayette Unit 2	0.04
	W. A. Parish Unit WAP4*	
Scrubber Retrofits	Harrington 061B	0.06
	Harrington 062B	0.06
	Coleto Creek Unit 1	0.06
	W. A. Parish WAP5	0.06
	W. A. Parish WAP6	0.06
	Welsh Unit 1	0.06
DSI	Harrington 061B	0.27 (in the alternative)

*For Unit WAP4, BART is to limit fuel use to pipeline natural gas, as defined at 40 CFR 72.2. As provided for in 40 CFR 72.2, pipeline natural gas contains 0.5 grains or less of total sulfur per 100 standard cubic feet. This is equivalent to an SO_2 emission rate of 0.0006 lb/MMBtu.

We propose that the following sources comply with these limits within five years of the effective date of our final rule: Coleto Creek Unit 1; Harrington Units 061B (for a limit consistent with scrubber retrofit) and 062B; W. A. Parish Units WAP5 and WAP6; 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 past actions we have typically required that scrubber retrofits under BART be operational within five years.[346]

We are proposing an alternative BART limit based on DSI at 50 percent for Harrington Unit 061B with a proposed compliance date within two years of the effective date of our final rule. We believe that two years is appropriate as the installation of DSI systems is less complex and time consuming than the construction of a scrubber. We also propose to require a DSI performance evaluation, as more fully described in Section IX.A.3, within one year of the effective date of our final rule. In Section VIII.A.2 we also provide an option for Harrington to agree as part of this FIP to convert to natural gas by no later than January 1, 2025.

For Martin Lake Units 1, 2, and 3, we propose that compliance with these limits be within three years of the effective date of our final rule. 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 than the construction of a new scrubber.

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

2. Potential Process for Alternative Scrubber Upgrade Emission Limits

[346] *See* 76 FR 81729, 81758 (December 28, 2011) and 81 FR 66332, 66416 (September 27, 2016), where we promulgated regional haze FIPs for Oklahoma and Arkansas, respectively. These FIPs required BART SO_2 emission limits on coal-fired EGUs based on new scrubber retrofits with a compliance date of no later than five years from the effective date of the final rule.

In our 2023 BART FIP TSD, we discuss how we calculated the SO_2 removal efficiency of the units we analyzed for scrubber upgrades. Since we do not have CEMS data for the inlet of the scrubbers (we only have CEMS data for the outlet of the scrubbers) and we do not have recent site-specific testing from the facility to more accurately determine the current control efficiency of the scrubbers, we estimated the current removal efficiency of each scrubber using formulas. These formulas utilize the reported sulfur content and tonnages of the fuels burned at each unit to calculate the theoretical uncontrolled SO_2 emissions. The calculated theoretical uncontrolled SO_2 emissions and CEMS data for the scrubber outlet SO_2 emissions are then used to calculate scrubber efficiency. Given a lack of updated source-specific information resulting in an estimated control efficiency based on available fuel usage and SO_2 emissions data, we cannot assure accuracy in our quantification of scrubber efficiency. However, despite the potential for inaccurate information regarding scrubber efficiency, based on the results of our scrubber upgrade cost analysis, we do not believe that any such error in calculating the true tons of SO_2 removed affects our proposed determination that scrubber upgrades are cost-effective. Even if we were 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 an SO_2 emission limit that is based on 95 percent removal. This is below the upper end of what an upgraded wet SO_2 scrubber can achieve, which is 98–99 percent, as we have noted in our 2023 BART FIP TSD. We believe that a 95 percent control assumption provides an adequate margin of error for 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 owner 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.
>>
>> (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.

3. DSI Performance Evaluation for Harrington Unit 061B

We are proposing that SO_2 BART for Harrington Unit 061B should be based on the installation of SDA at an emission limit of 0.06 lb/MMBtu based on a 30 BOD and in the alternative, we are proposing that SO_2 BART should be based on DSI at 50 percent control efficiency at an emission limit of 0.27 lb/MMBtu based on a 30 BOD with the requirement to conduct a DSI performance evaluation and submit to the EPA no later than one (1) year from the effective date of our final rule. We believe Unit 061B is likely capable of achieving an SO_2 emission limit of 0.27 lb/MMBtu with DSI, but are not certain whether the unit could achieve a lower emission limit on a 30 BOD or what the potential impacts to PM emissions could be at higher injections rates necessary for higher control efficiencies using the existing ESP. The purpose of the DSI performance evaluation is to determine the lowest SO_2 emission rate Unit 061B would be able to sustainably achieve on a 30 BOD with DSI as well as the potential control efficiencies achievable with upgraded particulate removal and to determine how compliance with such an emission rate would impact our cost estimates for DSI. Therefore, as part of the performance evaluation, we are also proposing to require an estimate of the costs of DSI for each of the three control scenarios specified in 1.a through 1.c.

Should we require an SO_2 emission limit based on DSI for Harrington Unit 061B in our final FIP, we are proposing the following requirements for a DSI performance evaluation:

(1) The performance evaluation must be conducted by a third-party engineering firm and must determine the potential lowest sustainable SO_2 emission rate on a 30 BOD with DSI for each of the following control scenarios:

    (a) DSI with the existing ESP for particulate removal;

    (b) DSI with a new ESP installation for particulate removal;

    (c) DSI with a new fabric filter installation for particulate removal.

(2) The performance evaluation must include an estimate of the costs for each of the three control scenarios specified in 1.a through 1.c. The cost estimates must include a

detailed breakdown of the capital costs and annual operation and maintenance costs for each control scenario as well as an estimate of the annual SO_2 emissions reductions under each control scenario. The cost estimates should adhere to the costing methodologies recommended in the EPA Air Pollution Control Cost Manual.[347]

(3) The facility must submit a detailed report of the performance evaluation and all supporting documentation to the EPA no later than one year from the effective date of our final BART FIP.

Based on the DSI performance evaluation, we will determine whether a revision of the SO_2 emission limit for Harrington Unit 061B is appropriate. Should we determine that a revision of the SO_2 emission limit is appropriate, we will propose a modification to the BART FIP after it has been promulgated.

4. PM BART

We propose that PM BART limits for the coal-fired units, Martin Lake Units 1, 2, and 3; Coleto Creek Unit 1; W. A. Parish Units WAP5 and WAP6; Welsh Unit 1; Harrington Units 061B and 062B; and Fayette Units 1 and 2 are 0.030 lb/MMBtu and work practice standards, shown in Table 28.

Table 28. PM BART Emissions Standards and Work Practice Standards

Unit Type	**PM BART Proposal**
Coal-Fired BART Units	0.030 lb/MMBtu filterable PM Table 3 to Subpart UUUUU
Gas-Fired Only BART Units	Pipeline quality natural gas

[347] EPA Air Pollution Control Cost Manual, Seventh Edition, April 2021 available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual.

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 BART for W. A. Parish WAP4 is to limit fuel to pipeline natural gas, as defined at 40 CFR 72.2.

B. CSAPR Better-Than-BART

We propose that, if this proposal to implement source-specific BART requirements at certain EGUs in Texas is finalized, the EPA's analytical basis for our 2017 CSAPR Better-than-BART determination will be restored,[348] which concluded that implementation of CSAPR in the remaining covered states will continue to meet the criteria for a BART alternative. This will also resolve the claims in the 2017 and 2020 petitions for consideration. We are therefore proposing to deny the 2020 petition for partial reconsideration of our September 2017 Final Rule affirming 40 CFR 51.308(e)(4) and our subsequent 2020 denial of a 2017 petition for reconsideration of that rule. This proposed reaffirmation will allow the continued reliance on CSAPR participation as a BART alternative for BART-eligible EGUs for a given pollutant in states whose EGUs continue to participate in a CSAPR trading program for that pollutant.

X. Environmental Justice Considerations

The EPA defines environmental justice (EJ) as "the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies." The EPA further defines the term fair treatment to mean that "no group of people should bear a disproportionate burden of environmental harms and risks, including those

[348] 82 FR 45481.

resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies."[349] Recognizing the importance of these considerations to local communities, the EPA conducted an environmental justice screening analysis around the location of the facilities associated with this action to identify potential environmental stressors on these communities and the potential impacts of this action. However, the EPA is providing the information associated with this analysis for informational purposes only. The information provided herein is not a basis of the proposed action.

The EPA conducted the screening analyses using EJScreen, an EJ mapping and screening tool that provides the EPA with a nationally consistent dataset and approach for combining various environmental and demographic indicators.[350] The EJScreen tool presents these indicators at a Census block group (CBG) level or a larger user-specified "buffer" area that covers multiple CBGs.[351] An individual CBG is a cluster of contiguous blocks within the same census tract and generally contains between 600 and 3,000 people. EJScreen is not a tool for performing in-depth risk analysis, but is instead a screening tool that provides an initial representation of indicators related to EJ and is subject to uncertainty in some underlying data (*e.g.,* some environmental indicators are based on monitoring data which are not uniformly available; others are based on self-reported data).[352] For informational purposes, we have summarized EJScreen data within larger "buffer" areas covering multiple block groups and representing the average resident within the buffer areas surrounding the BART facilities.

---

[349] See *https://www.epa.gov/environmentaljustice/learn-about-environmental-justice*.
[350] The EJSCREEN tool is available at *https://www.epa.gov/ejscreen*.
[351] *See https://www.census.gov/programs-surveys/geography/about/glossary.html*.
[352] In addition, EJSCREEN relies on the five-year block group estimates from the U.S. Census American Community Survey. The advantage of using five-year over single-year estimates is increased statistical reliability of the data (*i.e.,* lower sampling error), particularly for small geographic areas and population groups. For more information, see *https://www.census.gov/content/dam/Census/library/publications/2020/acs/acs_general_ handbook_2020.pdf.*

EJScreen environmental indicators help screen for locations where residents may experience a higher overall pollution burden than would be expected for a block group with the same total population in the U.S. These indicators of overall pollution burden include estimates of ambient particulate matter ($PM_{2.5}$) and ozone concentration, a score for traffic proximity and volume, percentage of pre-1960 housing units (lead paint indicator), and scores for proximity to Superfund sites, risk management plan (RMP) sites, and hazardous waste facilities.[353] EJScreen also provides information on demographic indicators, including percent low-income, communities of color, linguistic isolation, and less than high school education.

The EPA prepared EJScreen reports covering buffer areas of approximately 6-mile radii around the BART facilities. From those reports, one BART facility, Harrington Station, showed EJ indices greater than the 80th national percentiles[354], which were for ozone, lead paint, and RMP facility proximity, none of which are regulated by this proposed action. No BART facility showed an EJ index greater than 80th national percentile for $PM_{2.5}$, diesel particulate matter, air toxics cancer risk, air toxics respiratory hazard index, traffic proximity, hazardous waste site proximity, underground storage tanks, or wastewater discharge. The full, detailed EJScreen reports are provided in the docket for this rulemaking.

This action is proposing to promulgate a FIP to address BART requirements that are not adequately satisfied by the Texas Regional Haze SIP. The proposed rule is proposing SO_2 and PM BART limits on EGUs in Texas to fulfill regional haze program requirements and additionally disapproving portions of the Texas Regional Haze SIP related to PM BART.

---

[353] For additional information on environmental indicators and proximity scores in EJSCREEN, *see* "EJSCREEN Environmental Justice Mapping and Screening Tool: EJSCREEN Technical Documentation," Chapter 3 and Appendix C (September 2019) at *https://www.epa.gov/sites/default/files/2021-04/documents/ejscreen_technical_document.pdf.*

[354] For a place at the 80th percentile nationwide, that means 20% of the U.S. population has a higher value. EPA identified the 80th percentile filter as an initial starting point for interpreting EJScreen results. The use of an initial filter promotes consistency for EPA programs and regions when interpreting screening results.

Exposure to PM and SO_2 is associated with significant public health effects. Short-term exposures to SO_2 can harm the human respiratory system and make breathing difficult. People with asthma, particularly children, are sensitive to these effects of SO_2.[355] Exposure to PM can affect both the lungs and heart and is associated with: premature death in people with heart or lung disease, nonfatal heart attacks, irregular heartbeat, aggravated asthma, decreased lung function, and increased respiratory symptoms, such as irritation of the airways, coughing or difficulty breathing. People with heart or lung diseases or conditions, children, and older adults are the most likely to be affected by PM exposure.[356] Therefore, we expect that these requirements for EGUs in Texas, if finalized, and resulting emissions reductions will contribute to reduced environmental and health impacts on all populations impacted by emissions from these sources, including populations experiencing a higher overall pollution burden, people of color and low-income populations. There is nothing in the record which indicates that this proposed action, if finalized, would have disproportionately high or adverse human health or environmental effects on communities with environmental justice concerns.

XI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Overview

This action is exempt from review by the Office of Management and Budget (OMB) because the proposed FIP, if finalized, would not constitute a rule of general applicability, as it proposes source specific requirements for electric generating units at six different facilities located in Texas.

B. Paperwork Reduction Act

[355] See *https://www.epa.gov/so2-pollution/sulfur-dioxide-basics#effects*.
[356] See *https://www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm*.

This action does not impose any new information collection burden under the PRA. OMB has previously approved the information collection activities contained in the existing regulations and has assigned OMB control number 2060–0667. Because the proposed source specific BART emission limits apply to only six different facilities, the Paperwork Reduction Act does not apply. *See* 5 CFR 1320.3(c).

Additionally, the proposed withdrawal of the Texas SO_2 Trading Program does not impose any new or revised information collection burden under the provisions of the Paperwork Reduction Act (PRA), 44 U.S.C. Section 3501 *et seq*. OMB has previously approved the information collection activities for the Texas SO_2 Trading Program as part of the most recent information collection request renewal for the CSAPR trading programs, which was assigned OMB control number 2060–0667. The withdrawal of the Texas SO_2 Trading Program does not change any collection requests required as part of the CSAPR trading programs. Furthermore, the withdrawal of the Texas SO_2 Trading Program will cause no change in information collection burden related to SO_2 requirements because the sources that are currently participating in the Texas SO_2 Trading Program have the same SO_2 monitoring and reporting requirements under the Acid Rain Program. Thus, the withdrawal of the Texas SO_2 Trading Program proposed in this action will not change any collection burden that these sources are subject to under either the CSAPR trading programs or the Acid Rain Program.

C. Regulatory Flexibility Act

I certify that this action will not have a significant impact on a substantial number of small entities under the RFA. This action will not impose any requirements on small entities. The proposed FIP action, if finalized, will apply to EGUs at six facilities, none of which are small entities as defined by the RFA.

D. Unfunded Mandates Reform Act

The 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 specific EGUs located at six named facilities, the 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

EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that EPA has reason to believe may disproportionately affect children, per the definition of "covered regulatory action" in section 2-202 of the Executive Order. Therefore, this action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk. Since this action does not concern human health, EPA's Policy on Children's Health also does not apply.

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, the EPA must consider and use "voluntary consensus standards" (VCS) if available and applicable when developing programs and policies unless doing so would be inconsistent with applicable law or otherwise impractical. The EPA believes that VCS are inapplicable to this action. This 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) 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 (people of color and/or Indigenous peoples) and low-income populations.

The EPA believes that the human health or environmental conditions that exist prior to this action have the potential to result in disproportionate and adverse human health or environmental effects on people of color, low-income populations and/or Indigenous peoples. As explained further in Section X, the EPA's screening analysis provides an assessment of indicators related to environmental justice and overall pollution burden and demonstrates the potential for disproportionate and adverse effects on the areas located near at least one of the facilities subject to this action.

The EPA believes that this action, if finalized, is not likely to change the human health or environmental conditions, unrelated to SO_2 emissions, that exist prior to this action and that have the potential to result in disproportionate and adverse human health or environmental effects on people of color, low-income populations and/or Indigenous peoples. For example, this action is not expected to reduce potential community impacts associated with ozone, lead paint, or RMP facility status. However, the action, if finalized, is expected to reduce any potential existing disproportionate and adverse effects associated with SO_2 emissions from the sources covered by this action. This action, if finalized, will significantly reduce SO_2 emissions in the State of Texas, which is anticipated to improve air quality. The analyses and proposed requirements included in this proposed rulemaking are consistent with and commensurate with the Regional Haze Rule and how that rule functions. As discussed in Section X, exposure to SO_2 is associated with significant public health effects.

For informational purposes in a manner consistent with both the CAA and EO 12898, the EPA conducted an EJScreen analysis, considered a large radius around the BART facilities as well as environmental indicators beyond the scope of this action, as discussed in Section X. The EPA intends to promote fair treatment and provide meaningful involvement in developing the final action through the public notice and comment process. This will include a virtual public hearing and public comment period, as well as additional outreach to promote public engagement. Information related to this action will be available on the EPA's website as well as in the docket for this action.

The information supporting this Executive Order review is contained in Section X of this Preamble as well as throughout the Preamble, and all supporting documents have been placed in the public docket for this action.

K. Determinations Under CAA Section 307(b)(1) and (d)

Section 307(b)(1) of the CAA governs judicial review of final actions by the EPA. This section provides, in part, that petitions for review must be filed in the U.S. Court of Appeals for the D.C. Circuit: (i) when the agency action consists of "nationally applicable regulations promulgated, or final actions taken, by the Administrator," or (ii) when such action is locally or regionally applicable, but "such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and publishes that such action is based on such a determination." For locally or regionally applicable final actions, the CAA reserves to the Administrator complete discretion whether to invoke the exception in (ii).

This proposed action, if finalized, will be "nationally applicable" within the meaning of CAA section 307(b)(1). As set forth in Section V, the EPA proposes to deny the 2020 petition for partial reconsideration of our September 2017 Final Rule affirming 40 CFR 51.308(e)(4) and our subsequent 2020 denial of a 2017 petition for reconsideration of that rule. This denial, if finalized, will once again reaffirm the continued validity of the CSAPR better-than-BART provision at 40 CFR 51.308(e)(4), which is a nationally applicable regulation. The EPA's proposed denial of the 2020 petition for partial reconsideration is dependent on the EPA's promulgation of source-specific BART emissions limits in Texas. As explained in Section IV, the proposed withdrawal of the Texas SO_2 Trading Program and proposed adoption of source-specific BART limits for EGUs in Texas allows the EPA to restore the analytical basis for 40 CFR 51.308(e)(4), as set forth in our September 2017 Final Rule affirming the 2012 CSAPR better-than-BART determination. The CSAPR better-than-BART provision at 40 CFR 51.308(e)(4) allows states covered by a CSAPR trading program in 40 CFR 52.38 or 52.39 (or a SIP-approved trading program meeting these requirements) to implement those trading programs in lieu of source-specific BART limits for BART-eligible EGU sources. Currently, 19 states located across five of the ten EPA regions and in seven judicial circuits are included in at least one of the CSAPR trading programs and rely on these programs in lieu of source-specific BART, pursuant to 40 CFR 51.308(e)(4). The EPA's restoration of the analytical basis for 40 CFR 51.308(e)(4) would thus affect all of these states and BART-eligible EGU sources located in these states.

In the alternative, to the extent a court finds this proposal, if finalized, to be locally or regionally applicable, the Administrator intends to exercise the complete discretion afforded to him under the CAA to make and publish a finding that this action is based on a determination of "nationwide scope or effect" within the meaning of CAA section 307(b)(1).[357] First, this proposed action, if finalized, would be based on a determination of nationwide scope or effect for the same reasons identified above with respect to this action being "nationally applicable" – namely, because it would reaffirm the validity of 40 CFR 51.308(e)(4). Currently, 19 states would be directly affected by our decision to reaffirm the continued validity of the CSAPR better-than-BART provision at 40 CFR 51.308(e)(4), and these states represent a wide

[357] In deciding whether to invoke the exception by making and publishing a finding that an action is based on a determination of nationwide scope or effect, the Administrator takes into account a number of policy considerations, including his judgment balancing the benefit of obtaining the D.C. Circuit's authoritative centralized review versus allowing development of the issue in other contexts and the best use of agency resources.

geographic area falling within nine different judicial circuits.[358] Second, underlying the EPA's decision to reaffirm the validity of 40 CFR 51.308(e)(4) is our proposed action to withdraw the Texas SO_2 Trading Program and instead to adopt source-specific BART limits for SO_2 at the relevant Texas EGU sources, together with PM BART limits as part of a complete BART analysis that is required by the withdrawal of the Texas SO_2 Trading Program as a BART alternative, as explained in Section IV. Thus, the source-specific BART control program for Texas is a necessary component of the proposed action because it provides the basis for the reaffirmation of our conclusion that CSAPR serves as an alternative to BART for EGU sources located in over half the states in the country. As explained in Section V, our proposed reaffirmation of the CSAPR better-than-BART provision depends on our finalization and implementation of source-specific BART emissions limits for BART-eligible EGUs in Texas, thus achieving (among other things) SO_2 emissions reductions comparable to the assumptions used in the September 2017 Final Rule affirming the 2012 CSAPR better-than-BART determination.

The Administrator intends to find that this is a matter on which national uniformity is desirable, to take advantage of the D.C. Circuit's administrative law expertise, and to facilitate the orderly development of the basic law under the Act. The Administrator also intends to find that consolidated review of this action in the D.C. Circuit will avoid piecemeal litigation in the regional circuits, further judicial economy, and eliminate the risk of inconsistent results for different states, and that a nationally consistent approach to implementation of CSAPR trading

[358] In the report on the 1977 Amendments that revised CAA section 307(b)(1), Congress noted that the Administrator's determination that the ''nationwide scope or effect'' exception applies would be appropriate for any action that has a scope or effect beyond a single judicial circuit. See H.R. Rep. No. 95–294 at 323–24, reprinted in 1977 U.S.C.C.A.N. 1402–03.

programs at EGUs nationwide to satisfy BART requirements constitutes the best use of agency resources.

For these reasons, this action, if finalized, will be nationally applicable or, alternatively, the Administrator intends to exercise the complete discretion afforded to him under the CAA to make and publish a finding that this action is based on a determination of nationwide scope or effect for purposes of CAA section 307(b)(1).

This proposed action is subject to the provisions of section 307(d). CAA section 307(d)(1)(B) provides that section 307(d) applies to, among other things, "the promulgation or revision of an implementation plan by the Administrator under [CAA section 110(c)]." 42 U.S.C. 7407(d)(1)(B). This action, if finalized, among other things, promulgates a federal implementation plan pursuant to the authority of section 110(c). To the extent any portion of this proposed action is not expressly identified under section 307(d)(1)(B), the Administrator determines that the provisions of section 307(d) apply to this proposed action. *See* CAA section 307(d)(1)(V) (the provisions of section 307(d) apply to "such other actions as the Administrator may determine").

List of Subjects

40 CFR Part 52

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

40 CFR Part 78

Environmental protection, Administrative practice and procedure, Air pollution control, Reporting and recordkeeping requirements, Sulfur dioxides.

40 CFR Part 97

Environmental protection, Administrative practice and procedure, Air pollution control, Intergovernmental relations, Nitrogen dioxide, Reporting and recordkeeping requirements, Sulfur dioxides.

Michael S. Regan,

Administrator.

For the reasons stated in the preamble, the EPA proposes to amend 40 CFR parts 52, 78 and 97 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. In § 52.2270, the second table in paragraph (e), titled “EPA Approved Nonregulatory Provisions and Quasi-Regulatory Measures in the Texas SIP,” is amended by removing the entry “Texas Regional Haze BART Requirement for EGUs for PM”

3. Section 52.2287 is added to Subpart SS to read as follows:

§ 52.2287 Best Available Retrofit Requirements (BART) for SO_2 and Particulate Matter; 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 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.

(1) Coal-Fired Units:

Unit	Proposed SO_2 emission limit (lb/MMBtu)	Compliance Date (from the effective date of the final rule)
Martin Lake 1	0.08	3 years
Martin Lake 2	0.08	3 years
Martin Lake 3	0.08	3 years
Coleto Creek 1	0.06	5 years

Fayette 1	0.04	1 year
Fayette 2	0.04	1 year
Harrington 061B	0.06	5 years
Harrington 062B	0.06	5 years
W. A. Parish WAP5	0.06	5 years
W. A. Parish WAP6	0.06	5 years
Welsh 1	0.06	5 years

(2) W. A. Parish WAP4 shall burn only pipeline natural gas, as defined in 40 CFR 72.2. Compliance for this unit shall be as of the effective date of the final rule.

(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 Martin Lake Units 1, 2, and 3; Coleto Creek Unit 1; W. A. Parish WAP5 and WAP6; 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) W. A. Parish WAP4 shall burn only pipeline natural gas, as defined in 40 CFR 72.2.

(3) Compliance for the units included in paragraph (d) of this section 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)(1). Compliance with the emission limits for SO_2 for those units covered under paragraph (c)(1) shall be determined by using data from a CEMS.

(2) Continuous emissions monitoring shall apply during all periods of operation of the units covered under paragraph (c)(1), 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 requirement for the unit covered under (c)(2) and (d)(2) shall be determined from documentation demonstrating the use of pipeline natural gas as defined in 40 CFR 72.2.

(4) 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, Air and Radiation Division, U.S. Environmental Protection Agency, Region 6, to the attention of Mail Code: ARD, at 1201 Elm Street, Suite 500, Dallas, Texas 75270. For each unit subject to the emissions limitation in this section and upon completion of the installation of CEMS as required in this section, the owner or operator shall comply with the following requirements:

(1) For each SO_2 emission limit in paragraph (c)(1) of 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 covered under (c)(1). 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) For the unit covered under (c)(2) and (d)(2), records sufficient to demonstrate that the fuel for the unit is pipeline natural gas.

(4) 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.

4. Section 52.2304 is amended by:

a. In paragraph (f), amending the heading by adding the text “and PM” at the end

b. Adding paragraph (f)(3).

The additions and revisions read as follows:

§ 52.2304 Visibility protection.

* * * * *

(f) *Measures Addressing Disapproval Associated with NO_x, SO_2, and PM.*

* * * * *

(3) The deficiencies associated with PM with respect to best available retrofit technology under section 169A of the Clean Air Act, as identified in EPA's disapproval of the regional haze plan submitted by Texas on March 31, 2009, are satisfied by § 52.2287.

5. Section 52.2312 is amended by:

a. In paragraph (a) replacing "Texas SO_2 Trading Program provisions set forth in subpart FFFFF of part 97 of this chapter" with "Texas source-specific BART limits set forth in § 52.2287"

b. Removing paragraph (b).

The revisions read as follows:

§ 52.2312 Requirements for the control of SO2 emissions to address in full or in part requirements related to BART, reasonable progress, and interstate visibility transport.

* * * * *

(a) The Texas source-specific BART limits set forth in § 52.2287 constitute the Federal Implementation Plan provisions fully addressing Texas' obligations with respect to best available retrofit technology under section 169A of the Act and the deficiencies associated with EPA's disapprovals in § 52.2304(d) and partially addressing Texas' obligations with respect to reasonable progress under section 169A of the Act, as those obligations relate to emissions of sulfur dioxide (SO_2) from electric generating units (EGUs).

PART 78—APPEAL PROCEDURES

6. The authority citation for part 78 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

§ 78.1 [Amended]

7. Amend Section 78.1 by:

a. In paragraph (a)(1)(i)(D), removing "FFFFF,"; and

b. Removing and reserving paragraph (b)(18).

§ 78.3 [Amended]

8. Amend Section 78.3 by:

a. In paragraphs (a)(4), (c)(7)(iv), and (d)(2)(iv), removing "FFFFF,"; and

b. In paragraph (d)(6), removing "FFFFF," and removing "§ 97.906,".

§ 78.4 [Amended]

9. Amend Section 78.4 by:

a. In paragraph (a)(1)(iv)(A), removing "CSAPR SO_2 Group 2 unit or CSAPR SO_2 Group 2 source, or Texas SO_2 Trading Program unit or Texas SO_2 Trading Program source" and adding in its place "or CSAPR SO_2 Group 2 unit or CSAPR SO_2 Group 2 source"; and

b. In paragraph (a)(1)(iv)(B), removing "CSAPR SO_2 Group 2 allowances, or Texas SO_2 Trading Program allowances" and adding in its place "or CSAPR SO_2 Group 2 allowances".

PART 97—FEDERAL NO_X BUDGET TRADING PROGRAM, CAIR NO_X AND SO_2 TRADING PROGRAMS, AND CSAPR NO_X AND SO_2 TRADING PROGRAMS

10. The authority citation for part 97 is revised to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7426, 7601, and 7651, *et seq.*

11. Revise the part heading for part 97 to read as set forth above.

12. Remove and reserve the entirety of Subpart FFFFF consisting of §§ 97.901 through 97.935.