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ENVIRONMENTAL PROTECTION AGENCY **6560-50-P**

40 CFR Part 52

EPA-R08-OAR-2011-0770, FRL-9650-7

Approval and Promulgation of Implementation Plans; State of Colorado; Regional Haze State Implementation Plan

AGENCY: Environmental Protection Agency.

ACTION: Proposed rule.

SUMMARY: EPA is proposing to approve a State implementation plan (SIP) revision submitted by the State of Colorado on May 25, 2011 that addresses regional haze (RH). EPA is proposing to determine that the plan submitted by Colorado satisfies the requirements of the Clean Air Act (CAA or "the Act") and our rules that require states to prevent any future and remedy any existing man-made impairment of visibility in mandatory Class I areas caused by emissions of air pollutants from numerous sources located over a wide geographic area (also referred to as the "regional haze program"). States are required to assure reasonable progress toward the national goal of achieving natural visibility conditions in Class I areas. EPA is taking this action pursuant to section 110 of the CAA.

DATES: Written comments must be received at the address below on or before [insert date 60 days from the date of publication in the Federal Register]

ADDRESSES: Submit your comments, identified by Docket ID No. EPA-R08-OAR-2011-0770, by one of the following methods:

- http://www.regulations.gov. Follow the on-line instructions for submitting comments.
- E-mail: dygowski.laurel@epa.gov

- Fax: (303) 312-6064 (please alert the individual listed in the **FOR FURTHER INFORMATION CONTACT** if you are faxing comments).
- Mail: Carl Daly, Director, Air Program, Environmental Protection Agency (EPA), Region 8, Mailcode 8P-AR, 1595 Wynkoop Street, Denver, Colorado 80202-1129.
- Hand Delivery: Carl Daly, Director, Air Program, Environmental Protection Agency (EPA), Region 8, Mailcode 8P-AR, 1595 Wynkoop, Denver, Colorado 80202-1129. Such deliveries are only accepted Monday through Friday, 8:00 a.m. to 4:30 p.m., excluding Federal holidays. Special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA-R08-OAR-2011-0770. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at http://www.regulations.gov, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through http://www.regulations.gov or e-mail. The http://www.regulations.gov Web site is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA, without going through http://www.regulations.gov, your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD-ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional instructions on submitting comments, go to Section I, "General Information" of the **SUPPLEMENTARY INFORMATION** section of this document.

Docket: All documents in the docket are listed in the http://www.regulations.gov index. Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly-available docket materials are available either electronically in http://www.regulations.gov or in hard copy at the Air Program, Environmental Protection Agency (EPA), Region 8, Mailcode 8P-AR, 1595 Wynkoop, Denver, Colorado 80202-1129. EPA requests that if at all possible, you contact the individual listed in the **FOR FURTHER INFORMATION CONTACT** section to view the hard copy of the docket. You may view the hard copy of the docket Monday through Friday, 8:00 a.m. to 4:00 p.m., excluding Federal holidays.

FOR FURTHER INFORMATION CONTACT: Laurel Dygowski, Air Program, U.S. Environmental Protection Agency, Region 8, Mailcode 8P-AR, 1595 Wynkoop, Denver, Colorado 80202-1129, (303) 312-6144, dygowski.laurel@epa.gov.

SUPPLEMENTARY INFORMATION:

Table of Contents

For the purpose of this document, we are giving meaning to certain words or initials as follows:

i. The words or initials Act or CAA mean or refer to the Clean Air Act, unless the context indicates otherwise.

ii. The initials BACT mean or refer to Best Available Control Technology.

iii. The initials BART mean or refer to Best Available Retrofit Technology.

iv. The initials CAMx mean or refer to Comprehensive Air Quality Model.

v. The initials CMAQ mean or refer to Community Multi-Scale Air Quality modeling system.

vi. The initials CEMS mean or refer to continuous emission monitoring systems.

vii. The words Colorado and State mean the State of Colorado.

viii. The initials EC mean or refer to elemental carbon.

ix. The initials EGUs mean or refer to Electric Generating Units.

x. The words EPA, we, us or our mean or refer to the United States Environmental Protection Agency.

xi. The initials FETS mean or refer to the Fire Emission Tracking System.

xii. The initials FGD mean or refer to flue gas desulfurization.

xiii. The initials FGR mean or refer to external flue gas recirculation.

xiv. The initials FLMs mean or refer to Federal Land Managers.

xv. The initials FS mean or refer to the U.S. Forest Service.

xvi. The initials IMPROVE mean or refer to Interagency Monitoring of Protected Visual Environments monitoring network.

xvii. The initials IWAQM mean or refer to Interagency Workgroup on Air Quality Modeling.

xviii. The initials LB mean or refer to lean burn.

xix. The initials LNB mean or refer to low NO_x burner.

xx. The initials LTS mean or refer to Long-Term Strategy.

xxi. The initials MACT mean or refer to Maximum Achievable Control Technology

xxii. The initials NH_3 mean or refer to ammonia.

xxiii. The initials NO_x mean or refer to nitrogen oxides.

xxiv. The initials NPS mean or refer to National Park Service.

xxv. The initials OC mean or refer to organic carbon.

xxvi. The initials OFA mean or refer to overfire air.

xxvii. The initials $PM_{2.5}$ mean or refer to particulate matter with an aerodynamic diameter of less than 2.5 micrometers.

xxviii. The initials PM_{10} mean or refer to particulate matter with an aerodynamic diameter of less than 10 micrometers.

xxix. The initials PSAT mean or refer to Particle Source Apportionment Technology

xxx. The initials PSD mean or refer to Prevention of Signification Deterioration.

xxxi. The initials RAVI mean or refer to Reasonably Attributable Visibility Impairment.

xxxii. The initials RB mean or refer to rich burn.

xxxiii. The initials RH mean or refer to regional haze.

xxxiv. The initials RH SIP mean or refer to Colorado's RH State Implementation Plan.

xxxv. The initials RHR mean or refer to the Regional Haze Rule.

xxxvi. The initials RMC mean or refer to the Regional Modeling Center at the University of California Riverside.

xxxvii. The initials ROFA mean or refer to rotating overfire air.

xxxviii. The initials RP mean or refer to Reasonable Progress.

xxxix. The initials RPGs mean or refer to Reasonable Progress Goals.

xl. The initials RPOs mean or refer to regional planning organizations.

xli. The initials RRI mean or refer to rich reagent injection.

xlii. The initials SCR mean or refer to selective catalytic reduction.

xliii. The initials SIP mean or refer to State Implementation Plan.

xliv. The initials SNCR mean or refer to selective non-catalytic reduction.

xlv. The initials SO_2 mean or refer to sulfur dioxide.

xlvi. The initials SOFA mean or refer to separated overfire air.

xlvii. The initials TSD mean or refer to Technical Support Document.

xlviii. The initials URP mean or refer to Uniform Rate of Progress.

xlix. The initials VOC mean or refer to volatile organic compounds.

l. The initials WEP mean or refer to Weighted Emissions Potential.

li. The initials WRAP mean or refer to the Western Regional Air Partnership.

I. General Information

A. What Should I Consider as I Prepare My Comments for EPA?

1. *Submitting CBI.* Do not submit CBI to EPA through http://www.regulations.gov or e-mail. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD ROM that you mail to EPA, mark the outside of the disk or CD ROM as CBI and then identify electronically within the disk or CD ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the

information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

2. *Tips for Preparing Your Comments.* When submitting comments, remember to:

a. Identify the rulemaking by docket number and other identifying information (subject heading, Federal Register date and page number).

b. Follow directions - The agency may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.

c. Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.

d. Describe any assumptions and provide any technical information and/or data that you used.

e. If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.

f. Provide specific examples to illustrate your concerns, and suggest alternatives.

g. Explain your views as clearly as possible, avoiding the use of profanity or personal threats.

h. Make sure to submit your comments by the comment period deadline identified.

II. What Action is EPA Proposing to Take?

EPA is proposing to approve a SIP revision submitted by the State of Colorado on May 25, 2011 that addresses RH. In so doing, EPA is proposing to determine that the plan submitted by Colorado satisfies the requirements of 40 CFR 51.308.

III. Background

A. Regional Haze

RH is visibility impairment that is produced by a multitude of sources and activities which are located across a broad geographic area and emit fine particles ($PM_{2.5}$) (e.g., sulfates, nitrates, organic carbon (OC), elemental carbon (EC), and soil dust), and their precursors (e.g., sulfur dioxide (SO_2), nitrogen oxides (NO_x), and in some cases, ammonia (NH_3) and volatile organic compounds (VOC)). Fine particle precursors react in the atmosphere to form $PM_{2.5}$, which impairs visibility by scattering and absorbing light. Visibility impairment reduces the clarity, color, and visible distance that one can see. $PM_{2.5}$ can also cause serious health effects and mortality in humans and contributes to environmental effects such as acid deposition and eutrophication.

Data from the existing visibility monitoring network, the "Interagency Monitoring of Protected Visual Environments" (IMPROVE) monitoring network, show that visibility impairment caused by air pollution occurs virtually all the time at most national park and wilderness areas. The average visual range[1] in many Class I areas (i.e., national parks and memorial parks, wilderness areas, and international parks meeting certain size criteria) in the western United States is 100-150 kilometers, or about one-half to two-thirds of the visual range that would exist without anthropogenic air pollution. In most of the eastern Class I areas of the United States, the average visual range is less than 30 kilometers, or about one-fifth of the visual range that would exist under estimated natural conditions. 64 FR 35715 (July 1, 1999).

B. Requirements of the CAA and EPA's Regional Haze Rule (RHR)

In section 169A of the 1977 Amendments to the CAA, Congress created a program for protecting visibility in the nation's national parks and wilderness areas. This section of the CAA establishes as a national goal the "prevention of any future, and the remedying of any existing,

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

impairment of visibility in mandatory Class I Federal areas[2] which impairment results from manmade air pollution." On December 2, 1980, EPA promulgated regulations to address visibility impairment in Class I areas that is "reasonably attributable" to a single source or small group of sources, i.e., "reasonably attributable visibility impairment." 45 FR 80084. These regulations represented the first phase in addressing visibility impairment. EPA deferred action on RH that emanates from a variety of sources until monitoring, modeling and scientific knowledge about the relationships between pollutants and visibility impairment were improved.

Congress added section 169B to the CAA in 1990 to address RH issues. EPA promulgated a rule to address RH on July 1, 1999. 64 FR 35714 (July 1, 1999), codified at 40 CFR part 51, subpart P. The RHR revised the existing visibility regulations to integrate into the regulation provisions addressing RH impairment and established a comprehensive visibility protection program for Class I areas. The requirements for RH, found at 40 CFR 51.308 and 51.309, are included in EPA's visibility protection regulations at 40 CFR 51.300-309. Some of the main elements of the RH requirements are summarized in section III of this preamble. The requirement to submit a RH SIP applies to all 50 states, the District of Columbia and the Virgin Islands. 40 CFR 51.308(b) requires states to submit the first implementation plan addressing RH visibility impairment no later than December 17, 2007.[3]

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

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

Few states submitted a RH SIP prior to the December 17, 2007 deadline, and on January 15, 2009, EPA found that 37 states (including Colorado), the District of Columbia, and the Virgin Islands, had failed to submit SIPs addressing the RH requirements. 74 FR 2392. Once EPA has found that a state has failed to make a required submission, EPA is required to promulgate a FIP within two years unless the state submits a SIP and the Agency approves it within the two-year period. CAA §110(c)(1).

C. Roles of Agencies in Addressing Regional Haze

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

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

The Western Regional Air Partnership (WRAP) RPO is a collaborative effort of state governments, tribal governments, and various federal agencies established to initiate and coordinate activities associated with the management of RH, visibility and other air quality issues in the western United States. WRAP member State governments include: Alaska, Arizona, California, Colorado, Idaho, Montana, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming. Tribal members include Campo Band of Kumeyaay Indians, Confederated Salish and Kootenai Tribes, Cortina Indian Rancheria, Hopi Tribe, Hualapai Nation of the Grand Canyon, Native Village of Shungnak, Nez Perce Tribe, Northern Cheyenne Tribe, Pueblo of Acoma, Pueblo of San Felipe, and Shoshone-Bannock Tribes of Fort Hall.

IV. Requirements for Regional Haze SIPs

The following is a summary of the requirements of the RHR. See 40 CFR 51.308 for further detail regarding the requirements of the rule.

A. The CAA and the Regional Haze Rule

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

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

The RHR establishes the deciview (dv) as the principal metric or unit for expressing visibility. *See* 70 FR 39104, 39118. This visibility metric expresses uniform changes in the degree of haze in terms of common increments across the entire range of visibility conditions, from pristine to extremely hazy conditions. Visibility expressed in dvs is determined by using air quality measurements to estimate light extinction and then transforming the value of light extinction using a logarithm function. The dv is a more useful measure for tracking progress in improving visibility than light extinction itself because each dv change is an equal incremental change in visibility perceived by the human eye. Most people can detect a change in visibility at one dv.[4]

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

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

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

light extinction based on those estimates. We have provided guidance to states regarding how to calculate baseline, natural and current visibility conditions.[5]

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

C. Determination of Reasonable Progress Goals

The vehicle for ensuring continuing progress towards achieving the natural visibility goal is the submission of a series of RH SIPs from the states that establish two RPGs (i.e., two distinct goals, one for the "best" and one for the "worst" days) for every Class I area for each (approximately) 10-year implementation period. *See* 40 CFR 51.308(d), (f). The RHR does not mandate specific milestones or rates of progress, but instead calls for states to establish goals that provide for "reasonable progress" toward achieving natural visibility conditions. In setting

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

RPGs, states must provide for an improvement in visibility for the most impaired days over the (approximately) 10-year period of the SIP, and ensure no degradation in visibility for the least impaired days over the same period. *Id.*

In establishing RPGs, states are required to consider the following factors established in section 169A of the CAA and in our RHR at 40 CFR 51.308(d)(1)(i)(A): (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources. States must demonstrate in their SIPs how these factors are considered when selecting the RPGs for the best and worst days for each applicable Class I area. In setting the RPGs, states must also consider the rate of progress needed to reach natural visibility conditions by 2064 (referred to as the "uniform rate of progress" (URP) or the "glidepath") and the emission reduction measures needed to achieve that rate of progress over the 10-year period of the SIP. Uniform progress towards achievement of natural conditions by the year 2064 represents a rate of progress, which states are to use for analytical comparison to the amount of progress they expect to achieve. In setting RPGs, each state with one or more Class I areas ("Class I state") must also consult with potentially "contributing states," i.e., other nearby states with emission sources that may be affecting visibility impairment at the state's Class I areas. 40 CFR 51.308(d)(1)(iv). In determining whether a state's goals for visibility improvement provide for RP toward natural visibility conditions, EPA is required to evaluate the demonstrations developed by the state pursuant to paragraphs 40 CFR 51.308(d)(1)(i) and (d)(1)(ii). 40 CFR 51.308(d)(1)(iii).

D. Best Available Retrofit Technology (BART)

Section 169A of the CAA directs states to evaluate the use of retrofit controls at certain larger, often uncontrolled, older stationary sources in order to address visibility impacts from these sources. Specifically, section 169A(b)(2)(A) of the CAA requires states to revise their SIPs to contain such measures as may be necessary to make RP towards the natural visibility goal, including a requirement that certain categories of existing major stationary sources[6] built between 1962 and 1977 procure, install, and operate the "Best Available Retrofit Technology" as determined by the state. Under the RHR, states are directed to conduct BART determinations for such "BART-eligible" sources that may be anticipated to cause or contribute to any visibility impairment in a Class I area. Rather than requiring source-specific BART controls, states also have the flexibility to adopt an emissions trading program or other alternative program as long as the alternative provides greater RP towards improving visibility than BART.

On July 6, 2005, EPA published the *Guidelines for BART Determinations Under the Regional Haze Rule* at appendix Y to 40 CFR part 51 (hereinafter referred to as the "BART Guidelines") to assist states in determining which of their sources should be subject to the BART requirements and in determining appropriate emission limits for each applicable source. 70 FR 39104. In making a BART determination for a fossil fuel-fired electric generating plant with a total generating capacity in excess of 750 megawatts (MW), a state must use the approach set forth in the BART Guidelines. A state is encouraged, but not required, to follow the BART Guidelines in making BART determinations for other types of sources. Regardless of source size or type, a state must meet the requirements of the CAA and our regulations for selection of BART, and the state's BART analysis and determination must be reasonable in light of the overarching purpose of the RH program.

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[6] The set of "major stationary sources" potentially subject to BART is listed in CAA section 169A(g)(7).

The process of establishing BART emission limitations can be logically broken down into three steps: first, states identify those sources which meet the definition of "BART-eligible source" set forth in 40 CFR 51.301;[7] second, states determine which of such sources "emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area" (a source which fits this description is "subject to BART"); and third, for each source subject to BART, states then identify the best available type and level of control for reducing emissions.

States must address all visibility-impairing pollutants emitted by a source in the BART determination process. The most significant visibility impairing pollutants are SO_2, NO_x, and PM. EPA has stated that states should use their best judgment in determining whether VOC or NH_3 compounds impair visibility in Class I areas.

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

In their SIPs, states must identify the sources that are subject to BART and document their BART control determination analyses for such sources. In making their BART

[7] BART-eligible sources are those sources that have the potential to emit 250 tons or more of a visibility-impairing air pollutant, were not in operation prior to August 7, 1962, but were in existence on August 7, 1977, and whose operations fall within one or more of 26 specifically listed source categories. 40 CFR 51.301.

determinations, section 169A(g)(2) of the CAA requires that states consider the following factors when evaluating potential control technologies: (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.

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

E. Long-Term Strategy (LTS)

Consistent with the requirement in section 169A(b) of the CAA that states include in their RH SIP a 10 to 15 year strategy for making RP, section 51.308(d)(3) of the RHR requires that states include a LTS in their RH SIPs. The LTS is the compilation of all control measures a state will use during the implementation period of the specific SIP submittal to meet applicable RPGs. The LTS must include "enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals" for all Class I areas within, or affected by emissions from, the state. 40 CFR 51.308(d)(3).

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

States should consider all types of anthropogenic sources of visibility impairment in developing their LTS, including stationary, minor, mobile, and area sources. At a minimum, states must describe how each of the following seven factors listed below are taken into account in developing their LTS: (1) emission reductions due to ongoing air pollution control programs, including measures to address RAVI; (2) measures to mitigate the impacts of construction activities; (3) emissions limitations and schedules for compliance to achieve the RPG; (4) source retirement and replacement schedules; (5) smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the state for these purposes; (6) enforceability of emissions limitations and control measures; and (7) the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the LTS. 40 CFR 51.308(d)(3)(v).

F. Coordinating Regional Haze and Reasonably Attributable Visibility Impairment (RAVI)

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

G. Monitoring Strategy and Other Implementation Plan Requirements

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

The SIP must also provide for the following:

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

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

H. Consultation with States and Federal Land Managers (FLMs)

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

V. EPA's Evaluation of Colorado's Regional Haze SIP

The State of Colorado submitted a revision to its SIP to address the requirements for RH on May 25, 2011. The following is a discussion of our evaluation of the revision.

A. Affected Class I Areas

Pursuant to 40 CFR 51.308(d), the State identified 12 mandatory Class I areas in Colorado: Black Canyon of the Gunnison National Park, Eagles Nest Wilderness Area, Flat Tops Wilderness Area, Great Sand Dunes National Park, La Garita Wilderness Area, Maroon Bells-Snowmass Wilderness Area, Mesa Verde National Park, Mount Zirkel Wilderness Area, Rawah Wilderness Area, Rocky Mountain National Park, Weminuche Wilderness Area, and West Elk Wilderness Area. The State developed and submitted as part of its RH SIP technical support documents (TSDs) for each of the Class I areas. The Class I area TSDs include a detailed description of each area, along with photographs, summaries of monitoring data, an overview of current visibility conditions, and sources of pollution.

The State also identified in the TSD areas outside of the State that modeling shows may be impacted from emissions from Colorado.[8] These areas include: Upper Buffalo Wilderness in Arkansas; Petrified Forest National Park, Grand Canyon National Park, and Sycamore Canyon Wilderness in Arizona; Hercules-Glade Wilderness in Missouri; San Pedro Parks Wilderness, Bandelier National Monument, and Wheeler Peak in New Mexico; Wichita Mountains National Wildlife Refuge in Oklahoma; Wind Cave National Park and Badlands National Park in South Dakota; Canyonlands National Park and Capitol Reef National Park in Utah; and Bridger Wilderness in Wyoming.

B. Baseline Visibility, Natural Visibility, and Uniform Rate of Progress

As required by 40 CFR 51.308(d)(2), Colorado determined baseline visibility, natural visibility, and the URP for each Class I area in the State. Natural background visibility, as defined in our 2003 Natural Visibility Guidance, is estimated by calculating the expected light extinction using default estimates of natural concentrations of fine particle components adjusted by site-specific estimates of humidity. This calculation uses the IMPROVE equation, which is a formula for estimating light extinction from the estimated natural concentrations of fine particle components (or from components measured by the IMPROVE monitors). As documented in our 2003 Natural Visibility Guidance, EPA allows states to use "refined" or alternative approaches to this guidance to estimate the values that characterize the natural visibility conditions of Class I areas.

One alternative approach is to develop and justify the use of alternative estimates of natural concentrations of fine particle components. Another alternative is to use the ''new

[8] See Colorado TSD document titled *Colorado Visibility Impacts on nearby Class I Areas.*

IMPROVE equation'' that was adopted for use by the IMPROVE Steering Committee in December 2005.[9] The purpose of this refinement to the "old IMPROVE equation" is to provide more accurate estimates of the various factors that affect the calculation of light extinction.

Colorado used the new IMPROVE equation to calculate natural conditions and baseline visibility. The natural condition for each Class I area represents the visibility goal expressed in dvs for the 20% worst days and the 20% best days that would exist if there were only naturally occurring visibility impairment. In accordance with 40 CFR 51.308(d)(2)(iii), the State calculated natural visibility conditions based on available monitoring information and appropriate data analysis techniques and in accordance with our 2003 Natural Visibility Guidance. The State also calculated the number of dvs by which baseline conditions exceed natural conditions at each of its Class I areas to meet the requirements of 40 CFR 51.308(d)(2)(iv)(A).

Colorado has established baseline visibility for the best and worst visibility days for each Class I area based on data from the IMPROVE monitoring sites. Each IMPROVE monitor collects particulate concentration data which are converted into reconstructed light extinction through a complex calculation using the IMPROVE equation (see Class I area TSDs for more information on reconstructed light extinction and the IMPROVE equation). Per 40 CFR 51.308(d)(2)(i), the State calculated baseline visibility using a five-year average (2000 to 2004) of IMROVE data for both the 20% best and 20% worst days. The State's baseline calculations were made in accordance with our 2003 Tracking Progress Guidance.

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

Pursuant to 40 CFR 51.308(d)(1)(i)(B), the State calculated the URP for each of its Class I areas. For the 20% worst days, the URP is the calculation of the dv reduction needed to achieve natural conditions by 2064. For the 20% worst days, the State calculated the URP in dvs per year using the following formula: URP = [Baseline Condition - Natural Condition] / 60 years. In order to determine the uniform progress needed by 2018 to be on the path to achieving natural visibility conditions by 2064, the State multiplied the URP by the 14 years in the first planning period (2004-2018).

Table 1 shows the baseline visibility, natural conditions, and URP for each of the Class I areas.

Table 1 – Baseline Visibility, Natural Conditions, and Uniform Rate of Progress for Colorado Class I Areas

		20% Worst Days					20% Best Days
Colorado Class I Areas	Monitor Name	2000-2004 Baseline (dv)	2018 URP (dv)	Reduction Needed to Reach 2018 URP (delta dv)	2064 Natural Conditions (dv)	Delta Baseline – 2064 Natural Conditions (dv)	2000-2004 Baseline (dv)
Great Sand Dunes National Park and Preserve	GRSA1	12.78	11.35	1.43	6.66	6.12	4.50
Mesa Verde National Park	MEVE1	13.03	11.58	1.45	6.81	6.22	4.32
Mount Zirkel and Rawah Wilderness Area	MOZI1	10.52	9.48	1.04	6.08	4.44	1.61
Rocky Mountain National Park	RMHQ1	13.83	12.27	1.56	7.15	6.68	2.29
Weminuche Wilderness, Black Canyon of Gunnison, and La Garita Wilderness	WEMI1	10.33	9.37	0.96	6.21	4.12	3.11
Eagles Nest Wilderness,	WHRI1	9.61	8.78	0.83	6.06	3.55	0.70

Flat Tops Wilderness, Maroon Bells-Snowmass Wilderness, and West Elk Wilderness							

We have reviewed Colorado's calculations of baseline visibility, natural conditions, and URP. We find they have been calculated correctly and are proposing to approve them.

C. BART Determinations

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

1. BART Eligible Sources

The first step of a BART evaluation is to identify all the BART-eligible sources within the state's boundaries. Colorado identified the BART-eligible sources in Colorado by utilizing the approach set out in the BART Guidelines (70 FR 39158). This approach provides three criteria for identifying BART-eligible sources: (1) one or more emission units at the facility fit within one of the 26 categories listed in the BART Guidelines; (2) the emission unit or units began operation on or after August 6, 1962, and were in existence on August 6, 1977; and (3) combined potential emissions of any visibility-impairing pollutant from the units that meet the criteria in (1) and (2) are 250 tons or more per year. Colorado reviewed source permits and emission data from 2001-2003 to identify facilities in the BART source categories with potential emissions of 250 tons per year or more for any visibility-impairing pollutant from any unit or units that were in existence on August 7, 1977 and began operation on or after August 7, 1962. The BART Guidelines direct states to address SO_2, NO_x, and direct PM (including both coarse particulate matter (PM_{10}) and fine particulate matter ($PM_{2.5}$)) emissions as visibility-impairing pollutants and to exercise their "best judgment to determine whether VOC or NH_3 emissions from a source are likely to have an impact on visibility in an area." (70 FR 39162).

The State analyzed the emissions from VOC and NH_3 from sources in the State. VOC is a precursor to OC. The State eliminated VOC from further consideration in the RH SIP as it determined statewide point source emissions of VOC constitute a negligible portion of the emission inventory for OC (3 tons per year (tpy)). Colorado also determined that statewide point sources of NH_3 emissions are small. The State's emission inventory for 2001-2003 shows that point sources emitted 453 tpy of NH_3, while total State NH_3 emissions are 67,686 tpy. Thus, the State has eliminated NH_3 from further consideration.[10] We have reviewed this information and propose to accept this determination.

Table 2 lists the 12 sources that Colorado determined were BART-eligible.

2. Sources Subject to BART

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

[10] More details on the State's emission inventory can be found in *Colorado Emission Inventories Plan 2002d and PRP 2018b* in the Supporting and Related Materials section of the docket.

Class I areas.

a. Modeling Methodology

The BART Guidelines provide that states may use the CALPUFF[11] modeling system or another appropriate model to predict the visibility impacts from a single source on a Class I area and to, therefore, determine whether an individual source is anticipated to cause or contribute to impairment of visibility in Class I areas, i.e., "is subject to BART." The Guidelines state that CALPUFF is the best regulatory modeling application currently available for predicting a single source's contribution to visibility impairment (70 FR 39162).

The BART Guidelines also recommend that states develop a modeling protocol for making individual source attributions, and suggest that states may want to consult with EPA and their RPO to address any issues prior to modeling. Colorado used the CALPUFF model for Colorado BART sources in accordance with a protocol it developed titled *CALMET/CALPUFF BART Protocol for Class I Federal Area Individual Source Attribution Visibility Impairment Modeling Analysis*, October 24, 2005, which was approved by EPA and is included in the Supporting and Related Materials section of the docket. The Colorado protocol follows recommendations for long-range transport described in appendix W to 40 CFR part 51, *Guideline on Air Quality Models*, and in EPA's *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* as recommended by the BART Guidelines. (40 CFR part 51, appendix Y, section III.A.3).

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

To determine if each BART-eligible source has a significant impact on visibility, Colorado used the CALPUFF model to estimate daily visibility impacts above estimated natural conditions at each Class I area within 300 km of any BART-eligible facility, based on maximum actual 24-hour emissions over a three year period (2000-2002).

b. Contribution Threshold

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

Colorado used a contribution threshold of 0.5 dvs for determining which sources are subject to BART. The State's decision was based on the following factors: 0.5 dvs equates to the 5% extinction threshold for new sources under the Prevention of Significant Deterioration (PSD) New Source Review rules, and 0.5 dvs represents the limit of perceptible change. Although we do not agree with Colorado that these factors are always the appropriate ones to consider in determining which BART-eligible sources should be subject to BART in Colorado, we propose to approve the State's threshold of 0.5 dvs based on our own evaluation, discussed below. As shown in Table 2 below, Colorado exempted three of the 12 BART-eligible sources in the State from further review under the BART requirements. These three sources are Lamar Light and Power, Suncor Denver Refinery, and Ray D. Nixon Unit 1. According to Colorado's modeling, each of these sources had a visibility impact less than 0.5 dvs. As shown in Table 2, the visibility impact attributable to each of these sources is 0.06, 0.48, and 0.24 dvs, respectively. Given the relatively limited combined impact on visibility from these three sources, we propose to agree with Colorado that 0.5 dvs is a reasonable threshold for determining whether its BART-eligible sources are subject to BART.

Because our recommended modeling approach already incorporates choices that tend to lower peak daily visibility impact values,[12] our BART Guidelines state that a state should compare the 98th percentile (as opposed to the 90th or lower percentile) of CALPUFF modeling results against the "contribution" threshold established by the state for purposes of determining BART applicability. Colorado used a 98th percentile comparison that we find appropriate. Further explanation on use of the 98th versus 90th percentile value is provided at 70 FR 39121.

c.Sources Identified by Colorado as BART-Eligible and Subject to BART

Table 2 shows the sources that the State identified as BART-eligible and the results of the State's CALPUFF modeling. Colorado determined that the BART-eligible facilities with modeled impacts at all Class I areas less than 0.5 dvs were not subject to BART and those with impacts greater than 0.5 dvs were subject to BART (see Chapter 6.3 of the SIP).

Table 2 – Colorado BART-Eligible Sources and Subject-to-BART Modeling Results

[12] See our BART Guidelines, Section III.A.3.

Unit Name	Owner	Source Type	State Modeling Results – 98th Percentile Delta-Dv	Subject to BART?
Cemex – Lyons Cement Kiln and Dryer	Cemex	Portland Cement	1.53	Yes
CENC (Trigen-Colorado) Units 4 & 5	Colorado Energy Nations Company (CENC)	EGU	1.26	Yes
Cherokee Station – Unit 4	Public Service Company of Colorado (PSCO)	EGU	1.46	Yes
Comanche Station – Units 1 & 2	PSCO	EGU	0.7	Yes
Craig Station – Units 1 &2	Tri-State Generation and Transmission, Inc. (Tri-State)	EGU	2.69	Yes
Hayden Station – Units 1 & 2	PSCO	EGU	2.54	Yes
Lamar Light and Power – Unit 6	City of Lamar	EGU	0.06	No
Martin Drake Power Plant – Units 5, 6, & 7	Colorado Springs Utilities (CSU)	EGU	1.04	Yes
Pawnee Station – Unit 1	PSCO	EGU	1.19	Yes
Ray D. Nixon Power Plant – Unit 1	CSU	EGU	0.48[13]	No
Suncor Denver Refinery	Suncor	Refinery	0.24	No
Valmont Station – Unit 5	PSCO	EGU	1.59	Yes

3. BART Determinations and Federally Enforceable Limits

The third step of a BART evaluation is to perform the BART analysis. The BART Guidelines (70 FR 39164) describe the BART analysis as consisting of the following five steps:

- Step 1: Identify All Available Retrofit Control Technologies;
- Step 2: Eliminate Technically Infeasible Options;

[13] The State of Colorado originally modeled an impact of 0.57 dvs for Ray D. Nixon Power Plant. The source submitted refined modeling that showed an impact of 0.48 dvs. Both the State and EPA agree with the refined modeling submitted by the source.

- Step 3: Evaluate Control Effectiveness of Remaining Control Technologies;
- Step 4: Evaluate Impacts and Document the Results; and
- Step 5: Evaluate Visibility Impacts.

In determining BART, the State must consider the five statutory factors in section 169A of the CAA: (1) the costs of compliance; (2) the energy and 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). The five-factor analysis occurs during steps 4 and 5 of the BART analysis.

Colorado performed BART determinations for all of the sources subject to BART for NO_x, SO_2, and PM. We find that Colorado adequately considered all five steps above in its BART determinations.

State NO_x Control Criteria

For NO_x, the State developed criteria to assist in the selection of post-combustion controls for BART. For the highest-performing NO_x post-combustion control options (i.e., selective catalytic reduction (SCR) systems for electric generating units) that do not exceed a cost of $5,000 per ton and which provide a modeled visibility benefit of 0.50 dv or greater at the primary Class I Area affected, the State views that level of control as generally reasonable for BART. For lesser-performing NO_x post-combustion control options (e.g., selective non-catalytic reduction (SNCR) technologies for electric generating units) that do not exceed a cost of $5,000 per ton which provide a modeled visibility benefit of 0.20 dv or greater at the primary Class I Area affected, the State views that level of control as generally reasonable for BART.

EPA does not necessarily agree that the State's criteria for selecting NO_x controls would always be appropriate. First, the criteria appear to discriminate against SCR as a potential control option. Under the criteria, if the cost of SCR is under $5,000/ton and the modeled visibility benefit is 0.20 delta-dv or greater but less than 0.50 delta-dv, the State would reject SCR. Using the State's criteria, the State would find SNCR reasonable with the same $/ton and delta-dv values. We are not aware of a valid basis for applying different criteria to the two control options. In addition, we are aware of no basis for establishing benchmarks for post-combustion controls but not for other types of NO_x controls. The criteria may also preclude a reasonable weighing of the five factors where the delta dv benefit is over 0.5 but the cost is higher than $5,000/ton.

While we do not necessarily agree that the criteria used by the State would always be appropriate to select NO_x controls, we agree with the State's determinations for NO_x BART controls on the BART sources as discussed below.

<u>SO_2 Controls – Wet and Dry Scrubbing</u>

Scrubbing is one of the most common ways to control emissions of SO_2 from stationary sources. Scrubbing can consist of either wet flue gas desulfurization (FGD) or dry FGD. The State eliminated wet FGD from consideration as a BART control because of negative non-air quality environmental impacts. The main non-air quality environmental impact that the State identified for wet FGDs is very heavy water usage. Wet FGDs consume approximately 23% more water than dry FGDs depending on boiler size.[14] In Colorado, water law is based upon the doctrine of prior appropriation or "first in time - first in right," and the priority date is established by the date the water was first put to a beneficial use. The State reasoned that, depending upon

[14] "*Revised BART Analysis for Unit 1 & 2 Gerald Gentleman Station Sutherland, Nebraska: Nebraska Public Power District.*" Prepared by: HDF 701 Xenia Avenue South, Suite 600 Minneapolis, MN 55416 With control technology costs provided by: Sargent & Lundy.

whether and when a power plant first secured a water appropriation and whether such appropriation is adequate to supply the demand, there may be insufficient water appropriations available in some areas of the State, particularly in the Front Range area, to accommodate the added demands of wet FGD controls. The State also found that the water demands of wet FGDs would compete for what is already a scarce resource needed for Colorado's domestic, agricultural, and industrial demands.

Generally, wet FGD controls can achieve a slightly higher level of SO_2 control than dry FGDs on a percent capture basis. Considering this, the State determined that the non-air quality environmental impacts outweigh any incremental improvement in SO_2 emission reductions that would result from the use of wet FGDs rather than dry FGDs (see Chapter 6.4.1.3 of the SIP). EPA is proposing that the State provided adequate justification to eliminate the consideration of wet FGDs as SO_2 BART controls.

a. Visibility Improvement Modeling

The BART Guidelines provide that states may use the CALPUFF modeling system or another appropriate model to determine the visibility improvement expected at a Class I area from potential BART control technologies applied to the source. Colorado performed CALPUFF modeling to determine the degree of visibility improvement expected at a Class I area based on the controls evaluated for BART for the subject-to-BART sources, with the exception of Cemex. For Cemex, the State relied on modeling submitted by the source based on a modeling protocol approved by the State.

The BART Guidelines also recommend that states develop a modeling protocol for modeling visibility improvement, and suggest that states may want to consult with EPA and their RPO to address any issues prior to modeling. Colorado used the CALPUFF model for Colorado BART sources in accordance with a protocol it developed titled *Supplemental BART Analysis*

CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis, revised August 19, 2010, which was approved by EPA and is included in the Supporting and Related Materials section of the docket. The Colorado protocol follows recommendations for long-range transport described in appendix W to 40 CFR part 51, *Guideline on Air Quality Models*, and in EPA's *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts*, as recommended by the BART Guidelines. (40 CFR part 51, appendix Y, section III.D.5).

b. Summary of BART Determinations and Federally Enforceable Limits

In lieu of individual BART determinations, the State submitted a BART alternative as allowed for by 40 CFR 51.308(e)(2) for three of the subject-to-BART sources: Cherokee Station Unit 4, Pawnee Station Unit 1, and Valmont Station Unit 5. We provide a summary of the BART alternative in section IV.C.3.b.vii of this notice. We are proposing to approve the BART alternative. For the rest of the subject-to-BART sources, the State provided analyses that took into consideration the five factors as required by section 169A(g)(2) of the CAA. The State's five factor analyses, as well as additional technical information and materials, are included in Appendix C of the SIP. Chapter 6 of the SIP provides a summary of the five factor analyses. EPA is proposing to approve the BART determinations submitted by the State for Cemex Lyons Kiln and Dryer, CENC Unit 4 and Unit 5, Comanche Unit 1 and Unit 2, Craig Unit 2, Hayden Unit 1 and Unit 2, and Martin Drake Unit 5, Unit 6, and Unit 7. A summary of the BART determination for each source is provided below.

i. Cemex Lyons Dryer and Kiln

Background

The Cemex facility manufactures Portland cement and is located in Lyons, Colorado, approximately 20 miles from Rocky Mountain National Park. There are two BART-eligible units at the facility: the dryer and the kiln. The Lyons plant was originally constructed with a long dry kiln. In 1980, the kiln was cut to one-half its original length, and a flash vessel was added with a single-stage preheater. The permitted kiln feed rate is 120 tons per hour of raw material (kiln feed), and on average yields approximately 62 tons of clinker per hour. The kiln is the main source of SO_2 and NO_x emissions. The raw material dryer emits minor amounts of SO_2 and NO_x. The State's BART determination can be found in Chapter 6.4.3.1 and Appendix C of the SIP.

Baseline Emissions

The State has emissions data for the dryer from 1999, 2003, 2008, and 2009. The 1999 emissions are based on emission factors, whereas the 2003, 2008 and 2009 emissions are based on a stack test. The State has determined that the 2008 emissions best represent baseline emissions for the dryer since the State considers stack test data more reliable than emission factors. Furthermore, the 2008 clinker production is representative of typical operations because it falls within the normal range of the historical average. The 2008 baseline emissions for the dryer are: 10.41 tpy for NO_x; 0.89 tpy for SO_2; and 5.12 tpy for PM.

The State has determined that the 2002 emissions best represent baseline emissions for the kiln because they correspond to the high range for SO_2 emissions (which can vary significantly due to pyrites in the limestone) and the normal historical range for NO_x emissions and clinker production. The 2002 baseline emissions for the kiln are: 1,747 tpy for NO_x; 95 tpy for SO_2; and 8.5 tpy for PM.

SO_2 and NO_x BART Determination for the Dryer

CALPUFF modeling provided by the source, using a maximum SO_2 emission rate of 123.4 lbs/hour for both the dryer and kiln combined, shows a 98th percentile visibility impact of

0.78 delta dv at the most impacted Class I area, Rocky Mountain National Park. The State determined the modeling was performed correctly and EPA agrees with the State's assessment. The modeled 98th percentile visibility impact from the kiln is 0.76 dv. Thus, the visibility impact of the dryer alone is the resultant difference of 0.02 dv. Because of the extremely low visibility impact and emissions from the dryer, the State has determined that no meaningful visibility improvements would result from any conceivable controls on the dryer. The State has determined that SO_2 and NO_x BART for the Cemex dryer are the following existing emission limits: 36.7 tpy for SO_2 and 13.9 tpy for NO_x on a 12-month rolling average.

EPA is proposing to approve the State's SO_2 and NO_x BART determinations for the Cemex Lyons dryer. EPA agrees with the State that no significant visibility improvements would result from the application of controls on the dryer.

SO_2 BART Determination for the Kiln

The kiln has no current SO_2 controls, but approximately 80% of the SO_2 emissions are captured as part of the inherent control of the kiln process. The State determined that lime addition to kiln feed, fuel substitution (coal with tire-derived fuel), dry sorbent injection (DSI), and wet lime scrubbing (WLS) were technically feasible for reducing SO_2 emissions from the Cemex kiln. The State determined raw materials substitution was technically infeasible.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, and there are no remaining-useful-life issues for this source. A summary of the State's SO_2 BART analysis and the visibility impacts derived from modeling conducted by the source is provided in Table 3 below.

Table 3 – Summary of Cemex-Lyons Kiln SO_2 BART Analysis

Control Technology	Control Efficiency (%)	Annual Controlled Hourly SO_2	Emission Reduction (tpy)	Annualized Cost	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for

		Emissions (lbs/hr)				the Maximum 98th Percentile Impact)
Lime Addition to Kiln Feed	25	19	23.8	$3,640,178	$153,271	0.033
Fuel Substitution	40	15.2	38	$172,179	$4,531	0.034
DSI	50	12.7	47.5	--	--	0.036
WLS	90	2.5	85.5	$2,529,018	$29,579	0.040

Based upon its consideration and weighing of the five factors, the State has determined that no additional SO_2 emissions control on the kiln is reasonable for BART. The State determined that the added expense of any of the potential SO_2 controls was not reasonable for the small visibility improvement of 0.04 dvs or less. Despite not having cost information on DSI, the State determined that the minimal visibility improvement of 0.036 dv does not justify further consideration of this control technology. The State has determined that emissions from the 2002 baseline period represent BART for SO_2 emissions for the kiln. The State determined that the SO_2 BART emission limits for the kiln are 25.3 lbs/hour and 95.0 tpy of SO_2 (12-month rolling average).

We are proposing to approve the State's SO_2 BART determination for the Cemex Lyons kiln. The State's weighing of the factors was reasonable and resulted in a reasonable determination for SO_2 BART.

<u>NO_x BART Determination for the Kiln</u>

The kiln is currently uncontrolled for NO_x emissions. The State determined that water injection, firing coal supplemented with tire-derived fuel (TDF), indirect firing with low NO_x burners (LNBs), SNCR, and the combination of SNCR and LNBs were technically feasible and appropriate for reducing NO_x emissions from the Cemex kiln. The State determined that SCR is not commercially available for Portland cement kilns. EPA does not agree with the State's assertion that SCR is not commercially available for Portland cement kilns.

Although we disagree with the State's conclusion on the commercial availability of SCR for cement kilns, we accept the State's decision, for purposes of RH, not to analyze this control technology further. We note that EPA has acknowledged, in the context of establishing the New Source Performance Standards (NSPS) for Portland Cement Plants, substantial uncertainty regarding the cost effectiveness associated with the use of SCR at such plants. See 75 FR 54995. We expect the State to reevaluate this technology in subsequent RP planning periods.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, and there are no remaining-useful-life issues for this facility. A summary of the State's NO_x BART analysis and the visibility impacts derived from modeling conducted by the source is provided in Table 4 below.

Table 4 – Summary of Cemex-Lyons Kiln NO_x BART Analysis

Control Technology	Control Efficiency (%)	Annual Controlled Hourly NO_x Emissions (lbs/hr)	Emission Reduction (tpy)	Annualized Cost	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98th Percentile Impact)
Water Injection	7	431.8	122.3	$43,598	$356	0.22
Firing TDF	10	417.8	174.7	$172,179	$986	0.23
Indirect Firing with LNBs	20	371.4	349.4	$710,179	$2,034	0.28
SNCR	45	255.3	786.2	$1,636,636	$2,082	0.39
SNCR	48.5	239.4	846.1	$1,636,636	$1,934	0.41
SNCR with LNBs	55	208.9	960.9	$1,686,395	$1,755	0.44

As the table shows, SNCR with LNB could potentially achieve the greatest emission reductions for the control technologies evaluated. The Cemex-Lyons facility is a unique kiln system most accurately described as a modified long dry kiln. The characteristics of a modified long dry kiln system are not similar to either a long wet kiln or a multi-stage preheater/precalciner kiln. The temperature profile in a long dry kiln system (>1500°F) is significantly higher at the exit than a more typical preheater/precalciner kiln (650°F). This limits the location and residence time available for an effective NO_x control system. Because of this unique design, the State determined that SNCR and the combination of SNCR with LNBs have an uncertain level of control. Because the design of the Cemex kiln is unlike that for other kilns where SNCR has been successfully applied, it is uncertain whether SNCR can achieve emission reductions of 48.5%. The incremental reduction in visibility associated with SNCR in combination with LNBs would be 0.05 dv over just SNCR alone. Based on the uncertainty concerning the control efficiency of SNCR alone and SNCR with LNBs, and based on the small incremental visibility improvement that would result from SNCR in combination with LNBs over just SNCR, the State determined that BART for NO_x equates to an emission limit consistent with SNCR at 45% control. The State determined that the NO_x BART emission limits for the Cemex kiln are 255.3 pounds per hour (30-day rolling average) and 901.0 tons per year (12-month rolling average). The State assumes the emission limits can be met with the installation and operation of SNCR.

We agree with the State's conclusion, and we are proposing to approve the State's NO_x BART determination for the Cemex-Lyons kiln.

<u>PM BART Determination</u>

PM emissions from the kiln and dryer are currently controlled by fabric filter baghouses and wet dust suppression techniques. Current PM emission limits are in compliance with the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Source Categories;

Portland Cement Manufacturing Industry, 40 CFR part 63, subpart LLL. The existing NESHAP regulatory emission limits for the kiln are 0.275 lb/ton of dry feed and 20% opacity. For the dryer, the emission limit is 22.8 tpy and 10% opacity. For sources already regulated by a NESHAP standard, EPA stated the following in the BART guidelines: "We believe that, in many cases, it will be unlikely that States will identify emission controls more stringent than the MACT standards without identifying control options that would cost many thousands of dollars per ton. Unless there are new technologies subsequent to the MACT standards which would lead to cost effective increases in the level of control, you may rely on the MACT standards for purposes of BART." (70 FR 39163) (MACT means Maximum Achievable Control Technology).

The State determined that no new PM control methodologies could be identified that would improve upon the PM controls required in the NESHAP. The State determined that the current emission limit and control technology represent the most stringent level of control and are BART for PM for the Cemex-Lyons kiln and dryer. Per the BART Guidelines, if the BART source has the most stringent control technology and limit in place, a full five-factor analysis is not required (70 FR 39165). The State determined that PM BART emission limits for the kiln are 0.275 lb/ton of dry feed and 20% opacity and the emission limits for the dryer are 22.8 tpy (12-month rolling average) and 10% opacity. The State assumes the limits can be achieved with the operation of the current fabric filter baghouses.

We are proposing to approve the State's PM BART determinations for the Cemex-Lyons kiln and dryer. We agree with the State that the existing controls and emission limits represent the most stringent level of PM control for this type of facility.

ii. CENC Boilers 4 and 5

Background

This CENC facility is located adjacent, and supplies steam and electrical power, to the Coors Brewery in Golden, Colorado. The facility consists of five boilers and the associated equipment for coal and ash handling. Boilers 4 and 5 are the only units that are subject to BART. Boiler 4 mainly fires coal, but can also fire natural gas. Fuel oil may be used as a backup fuel, but has not been used in recent years. Boiler 5 fires coal, but uses oil as a backup fuel. Either boiler may also fire ethanol or sludge from the Coors Brewery. Boiler 4 is rated at 360 MMBtu/hr and Boiler 5 at 650 MMBtu/hr. Both boilers are pulverized-coal dry-bottom tangentially-fired boilers. The BART determination for CENC Boilers 4 and 5 can be found in Chapter 6.4.3.2 and Appendix C of the SIP.

SO_2 BART Determination

Boilers 4 and 5 are currently uncontrolled for SO_2. The State determined that DSI and SO_2 emission management were technically feasible for reducing SO_2 emissions from Boilers 4 and 5. The State determined that dry FGD controls were not technically feasible due to space constraints at the facility. Emissions management for SO_2 encompasses a variety of options to reduce SO_2 emissions, including dispatching natural gas-fired capacity, reducing total system load, and/or reducing coal firing rate to maintain a new peak SO_2 limit. The State also evaluated tightening the emission limits for Boiler 4 and 5 based on current operations.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, nor are there any remaining-useful-life issues for the source. A summary of the State's SO_2 BART analysis and the visibility impacts is provided in Tables 5 and 6 below. The State did not model the visibility improvement of SO_2 emissions management because the emission reduction from the control technology is negligible. The emission rate for each control option in the tables is reflective of the 30-day rolling average contained in the State's BART analysis. Baseline SO_2 emissions are 781 tpy for Boiler 4 and 1,406 tpy for Boiler 5 based on the average of 2006-2008 actual emissions.

Table 5 – Summary of CENC Boiler 4 SO_2 BART Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu)	Emission Reduction (tpy)	Annualized Cost	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98^{th} Percentile Impact)
SO_2 Emissions Management	0.13	.74	1	$44,299	$43,600	NA
DSI	60	.30	468	$1,766,000	$3,774	0.08

Table 6 – Summary of CENC Boiler 5 SO_2 BART Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu)	Emission Reduction (tpy)	Annualized Cost	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98^{th} Percentile Impact)
SO_2 Emissions Management	0.063	.82	0.8	$65,882	$78,095	NA
DSI	60	.33	844	$2,094,000	$2,482	0.13

Based on its consideration of the five factors, the State determined that SO_2 emissions management and DSI are not reasonable for BART. The State further evaluated emissions limit tightening based on current operations, which is a no-cost control option. The State determined that it would be appropriate to evaluate a lower emission limit based on percent sulfur and heat content. Based on the boiler sulfur to SO_2 conversions, the State has determined that the SO_2 BART emission limit for CENC Boiler 4 is 1.0 lb/MMBtu (30-day rolling average) and for

Boiler 5 is 1.0 lb/MMBtu (30-day rolling average). The details of the State's calculation can be found in the State's BART analysis.

We agree with the State's conclusions, and we are proposing to approve its SO_2 BART determinations for CENC Boiler 4 and Boiler 5.

NO_x BART Determination

Boilers 4 and 5 are currently uncontrolled for NO_x. The State determined that LNBs, LNBs plus separated overfire air (SOFA), SNCR, SNCR plus LNB plus SOFA, and SCR were technically feasible for reducing NO_x emissions at CENC Boilers 4 and 5. The State determined rich reagent injection (RRI), ECO System, and coal reburn with SNCR were technically infeasible.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, nor are there any remaining-useful-life issues for this source. A summary of the State's NO_x BART analysis and the visibility impacts is provided in Tables 7 and 8 below. The emission rate for each control option in the tables is reflective of the 30-day rolling average contained in the State's BART analysis. Baseline NO_x emissions are 600 tpy for Boiler 4 and 691 tpy for Boiler 5, based on the average of 2006-2008 actual emissions.

Table 7 – Summary of CENC Boiler 4 NO_x BART Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu) (30-day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98th Percentile Impact)
LNBs	7[15]	.52	59.9	$193,433	$3,227	0.05

[15] EPA's AP-42 emission factor tables estimate that LNBs can control 35 – 55%, and LNB with OFA can control 40 – 60%, of NOx emissions. However, due to the size and configuration (e.g. furnace dimensions) of the CENC boilers, the State has determined that the estimated control efficiency for LNBs and LNBs with OFA used in the analysis are reasonable.

SNCR	30	.40	179.8	$694,046	$3,860	0.07
LNBs + SOFA	18.5	.37	209.8	$678,305	$3,234	0.08
LNB+SOFA + SNCR	51	.22	368	$1,372,351	$3,729	0.12
SCR	79.6	.08	515.4	$4,201,038	$8,150	0.18

Table 8 – Summary of CENC Boiler 5 NO_x BART Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu) (30-day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98th Percentile Impact)
LNBs	7	.37	48.4	$249,858	$5,166	0.17
SNCR	30	.32	127.3	$815,829	$6,383	0.21
LNBs + SOFA	18.5	.28	207.3	$923,996	$4,458	0.21
LNBs+SOFA + SNCR	51	.19	353.7	$1,739,825	$4,918	0.26
SCR	79.6	.08	550.0	$6,469,610	$11,764	0.31

Based on its consideration of the five factors, the State determined BART is LNBs + SOFA for Boiler 4 and LNBs + SOFA + SNCR for Boiler 5. Although SCR achieves better emissions reductions, the State determined that SCR is not reasonable based on the high cost effectiveness values and the low visibility improvement afforded by this control. The State has determined that the NO_x BART emission limit for CENC Boiler 4 is 0.37 lb/MMBtu (30-day rolling average) and for Boiler 5 is 0.19 lb/MMBtu (30-day rolling average). The State assumes the BART emission limits can be achieved by the installation and operation of LNBs with SOFA on Boiler 4 and LNBs + SOFA + SNCR on Boiler 5.

Per the BART Guidelines, states may consider allowing sources to average emissions across any set of BART eligible emissions units within a fenceline, so long as the emission reductions from each pollutant being controlled for BART would be equal to those reductions that would be obtained by simply controlling each of the BART-eligible sources (70 FR 39172).

Pursuant to this, the State also established a combined NO_x BART limit for CENC Boiler 4 and Boiler 5 of 0.26 lb/MMBtu on a 30-day rolling average.

We agree with the State's conclusions, and we are proposing to approve the State's NO_x BART determinations for CENC Boiler 4 and Boiler 5.

PM BART Determination

CENC Boilers 4 and 5 are each equipped with fabric filter baghouses to control PM emissions with a current emission limit of 0.07 lb/MMBtu. Fabric filter baghouses are the most stringent control technology for controlling PM emissions, and stack tests show that the fabric filter baghouses are achieving a 98% reduction in PM. The State determined that PM BART for Boiler 4 and Boiler 5 is an emission limit of 0.07 lb/MMBtu. The State assumes the BART emission limit can be met with the operation of the current fabric filter baghouses.

While we do not agree with all of the State's assumptions and conclusions in arriving at a PM BART limit of 0.07 lb/MMBtu, we are proposing to approve the State's PM BART determinations for CENC Boiler 4 and Boiler 5. Based on our review/analysis, CENC is capable of achieving a lower emission limit than 0.07 lb/MMBtu with existing equipment. However, we anticipate that the visibility improvement that would result from lowering the limit from 0.07 lb/MMBtu to 0.03 lb/MMBtu would be insignificant. Under these circumstances, we propose to find that the State's BART determination was reasonable.

iii. PSCO Comanche Station Units 1 and 2

Background

Comanche Station is located in Pueblo, Colorado. It consists of three coal-fired EGUs, Units 1, 2, and 3. Unit 1 is rated at 325 megawatts (MW) and Unit 2 is rated at 335 MW. Unit 1 and Unit 2 are the only subject-to-BART units at Comanche Station. The boilers burn subbituminous coal as fuel and use natural gas for startup, shutdown, and flame stabilization. Both units are dry-bottom pulverized coal-fired boilers. Unit 1 is tangentially fired and Unit 2 is wall-fired.

In August of 2004, PSCO proposed to construct and operate Unit 3 at Comanche Station. As part of the project, PSCO proposed to install NO_x and SO_2 control devices on Unit1 and Unit 2 and take new emission limits on those units. In November 2008, PSCO installed LNBs with OFA and a lime spray dryer (LSD) on Unit 1, and in November 2007, PSCO installed LNBs with OFA and a LSD on Unit 2. Operation of the LSDs did not commence until June 3, 2009 for Unit 1 and January 10, 2009 for Unit 2. The State's BART determination for Comanche Station Units 1 and 2 can be found in Chapter 6.4.3.3 and Appendix C of the SIP.

SO_2 BART Determination

The State determined that the LSD on Unit 1 is achieving 76.1% control and the LSD on Unit 2 is achieving 81.9% control. Baseline SO_2 emissions are 1,557 tpy for Unit 1 and 1,244 tpy for Unit 2 based on 2009 actual emissions. The current emission limit for Units 1 and 2 is 0.12 lb/MMBtu each on a 30-day rolling average and a combined annual average of 0.10 lb/MMBtu. Per the BART Guidelines, for EGUs with preexisting post-combustion SO_2 controls achieving removal efficiencies of at least 50 percent, states should consider cost effective scrubber upgrades designed to improve the system's overall SO_2 removal efficiency (70 FR 39171). Under the BART Guidelines, a state is not required to evaluate the replacement of the current SO_2 controls if their removal efficiency is over 50%. The State's BART analysis evaluated numerous LSD upgrades including: 1) use of performance additives; 2) use of more reactive sorbent; 3) increasing the pulverization level of sorbent; 4) engineering redesign of atomizer or slurry injection system; and 5) additional equipment and maintenance. The State analyzed the potential upgrades and determined all upgrades were either technically infeasible or would not achieve a decrease in current SO_2 emissions.

The State also assessed emissions limit tightening based on current operations. The State reviewed available SO_2 emissions data from EPA's Clean Air Markets Division (CAMD) for 2009 and for part of 2010 (January – October 2010). Since the LSDs only recently commenced full operation, there was limited data available for the State to determine post-control achievable emissions. In its submittal to the State, PSCO provided additional information pertaining to emissions limit tightening. PSCO stated that during low-load operations the inlet temperature at the baghouse approaches the minimum acceptable level, lowering the overall SO_2 control efficiency during low-load operations. PSCO indicated that, due to the increased use of wind resources, the boilers will be required to cycle more frequently to accommodate intermittent wind resources, and, therefore, the units will run at low loads more frequently. As a result, the SO_2 reduction levels will be lower during those times.

Based on this information, the State determined that the limited emissions data from 2009 and 2010 may not accurately represent future plant emissions. In addition, since the LSDs only came on line recently, the State recognized that PSCO has limited operating experience with these units. Although PSCO has other units that are equipped with LSDs, Comanche Station Units 1 and 2 are the first such units in PSCO's system that are firing Powder River Basin coal. After startup of the LSDs in 2009, both units have had a number of days indicating zero emissions, presumably due to a unit shutdown. In many cases, emissions data shows that for one or more days following these events, the daily SO_2 emission rate is frequently well above 0.12 lb/MMBtu. In looking at the data, the State also found that both units have historically lower inlet temperatures to the scrubbers in the winter months, resulting in increased SO_2 emissions.

Based on the information discussed above, the State concluded that a tighter 30-day rolling average and annual average SO_2 emission limit is not feasible at this time for either unit. Based on its analysis, the State determined that the SO_2 BART emission limit for Comanche Station Unit 1 is 0.12 lb/MMBtu (30-day rolling average) and for Unit 2 is 0.12 lb/MMBtu (30-day rolling average). The State also established a SO_2 BART emission limit of 0.10 lb/MMBtu, combined annual average for both units.

We agree with the State's conclusions and are proposing to approve its SO_2 BART determinations for Comanche Station Unit 1 and Unit 2.

NO_x BART Determination

Comanche Station Units 1 and 2 currently have a NO_x permit limit of 0.20 lb/MMBtu on a 30-day rolling average for each unit and a combined annual average limit of 0.15 lb/MMBtu. The State determined that SCR and SNCR were technically feasible at Unit 1 and SCR was technically feasible for Unit 2. PSCO conducted testing in the fall of 2008 on Unit 2 using a temporary SNCR system. PSCO performed the testing following the installation of LNBs and OFA to determine if additional reductions could be achieved. PSCO primarily conducted testing at full load over a seven-day period using a single-level urea based SNCR system. The SNCR system is sensitive to temperature and average exhaust temperature in the injection area for Unit 2 was nearly 2,200 ºF, which exceeds the optimal temperature for the technology. During the test periods, NO_x reductions were less than 10%, and in some cases during testing, an actual increase in NO_x emissions was observed by PSCO. Based on the results of PSCO's test of SNCR on Unit 2, the State did not evaluate SNCR further as a control option for Unit 2. The State also determined that ECO system and RRI were technically infeasible for both units. The State did not evaluate rotating opposed fire air (ROFA) and reburning because they do not achieve better emission reductions than the current controls.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, nor are there any remaining-useful-life issues for this source. Baseline NO_x emissions from the 2009 calendar year are 1,511 tpy for Unit 1 and 2,349 tpy for Unit 2. A summary of the State's NO_x BART analysis and the visibility impacts is provided in Tables 9 and 10 below. The emission rate for each control option in the tables is reflective of the 30-day rolling average contained in the State's BART analysis.

Table 9 – Summary of Comanche Station Unit 1 NO_x BART Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu) (30-day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98th Percentile Impact)
SNCR	29.5	0.10	446	$1,624,100	$3,644	0.11
SCR	51	0.07	770	$12,265,014	$15,290	0.14

Table 10 – Summary of Comanche Station Unit 2 NO_x BART Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu) (30-day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98th Percentile Impact)
SCR	63	0.07	1480	$14,650,885	$9,900	0.17

Based on its consideration of the five factors, the State has determined that the NO_x BART emission limit for Comanche Station Unit 1is 0.20 lb/MMBtu (30-day rolling average) and for Unit 2 is 0.20 lb/MMBtu (30-day rolling average). The State also established a NO_x BART emission limit of 0.15 lb/MMBtu, combined annual average for both units.

The State assumes that the BART emission limits can be achieved through the operation of existing LNBs. Although the other alternatives achieve better emissions reductions, the State determined that the added expense of achieving lower limits through different controls was not reasonable based on the high cost effectiveness coupled with the low visibility improvement (under 0.2 dv) afforded.

We agree with the State's conclusions, and we are proposing to approve the State's NO_x BART determinations for Comanche Station Unit 1 and Unit 2.

PM BART Determination

Comanche Station Units 1 and 2 are each equipped with fabric filter baghouses to control PM emissions with an emission limit of 0.03 lb/MMBtu. Stack tests show that the fabric filter baghouses are achieving a 99% reduction in PM. Fabric filter baghouses are the most stringent control technology for controlling PM emissions. The State also evaluated what would constitute the most stringent level of control for PM by looking at recent Best Available Control Technology (BACT) determinations. Based on this evaluation, the State determined that an emission limit of 0.03 lb/MMBtu represents the most stringent level of control for this type of source. Consistent with the BART Guidelines, the State did not provide a full five-factor analysis because the State determined BART to be the most stringent control technology and limit. The State determined that the PM BART limit for Comanche Station Units 1 and 2 is 0.03 lb/MMBtu (30-day rolling average). The State assumes the BART limit can be met with the operation of the existing fabric filter baghouses.

We agree with the State's conclusions, and we are proposing to approve its PM BART determinations for Comanche Station Unit 1 and Unit 2.

iv. Tri-State Craig Units 1 and 2

Background

The Tri-State Generation & Transmission Association, Inc. (Tri-State) Craig Station is located in Moffat County approximately 2.5 miles southwest of the town of Craig, Colorado. This facility is a coal-fired power plant with a total net electric generating capacity of 1264 MW, consisting of three units. Only Units 1 and 2 are BART-eligible. Units 1 and 2 are dry-bottom pulverized coal-fired boilers and are each rated at a net capacity of 428 MW. The State's BART determination for Craig Units 1 and 2 can be found in Chapter 6.4.3.4 and Appendix C of the SIP.

SO_2 BART Determination

Craig Unit 1 and Unit 2 are currently controlled with wet FGD. The units have a current SO_2 emission limit of 0.16 lb/MMBtu on a 30-day rolling average and a requirement to achieve a 90% reduction of SO_2 (90-day rolling average). Per the BART Guidelines, for EGUs with preexisting post-combustion SO_2 controls achieving removal efficiencies of at least 50 percent, states should consider cost effective scrubber upgrades designed to improve the system's overall SO_2 removal efficiency (70 FR 39171). Under the BART Guidelines, a state is not required to evaluate the replacement of the current SO_2 controls if their removal efficiency is over 50%.

The State evaluated the following wet FGD upgrades: 1) elimination of bypass reheat; 2) installation of liquid distribution rings; 3) installation of perforated trays; 4) use of organic acid additives; 5) improve or upgrade scrubber auxiliary equipment; and 6) redesign spray header or nozzle configuration. Tri-State performed numerous upgrades at Units 1 and 2 during 2003-

2004. The State determined that Tri-State had installed all of the above upgrades with the exception of liquid distribution rings and use of organic additives. The State determined that the installation of perforated trays achieved the same objective as these upgrades.

The State evaluated emission limit tightening based on current operations. The State analyzed the baseline period (2006 – 2008) emission data from EPA's CAMD to determine the maximum and average 30-day rolling emission rates. The emissions data shows that the maximum 30-day rolling average was 0.08 lb/MMBtu for Unit 1 and 0.09 lb/MMBtu for Unit 2. The average 30-day rolling emission rate was 0.05 lb/MMBtu for Unit 1 and 0.08 for Unit 2. The daily maximum over the three-year period was 0.17 lb/MMBtu for Unit 1 and 0.16 lb/MMBtu for Unit 2. Table 11 shows the visibility improvement modeled by the State for possible lower SO_2 emission limits.

Table 11 – Craig Unit 1 and Unit 2 SO_2 Visibility Improvement

SO_2 Control	Emission Rate (lb/MMBtu) (30-day Rolling Average)	Craig Unit 1 – Visibility Improvement (Delta dv for the Maximum 98th Percentile Impact)	Craig Unit 2 – Visibility Improvement (Delta dv for the Maximum 98th Percentile Impact)
Wet FGD	0.11	0.03	0.03
Wet FGD	0.07	0.05	0.05

The State determined that an emission limit of 0.11 lb/MMBtu would be achievable without additional capital investment. The State determined that an emission limit lower than 0.11 lb/MMBtu would likely require additional capital expenditure and determined it was not reasonable for the incremental visibility improvement of 0.02. The State has determined that the SO_2 BART emission limit for Craig Unit 1 is 0.11 lb/MMBtu (30-day rolling average) and for Unit 2 is 0.11 lb/MMBtu (30-day rolling average). The State assumes that the BART emission limits can be achieved through the operation of the existing wet FGD.

We agree with the State's conclusions, and we are proposing to approve its SO_2 BART determinations for Craig Unit 1 and Unit 2.

NO_x BART Determination

Craig Units 1 and 2 are currently controlled with ultra low NO_x burners (ULNBs) plus OFA, achieving emission reductions of about 54 percent each. The State determined that combustion control refinements, neural network systems, SNCR, and SCR were technically feasible.[16] The State determined that ECO, RRI, ROFA, and coal reburn plus SNCR were not technically feasible. The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, nor are there any remaining-useful-life issues for this source. Baseline NO_x emissions are 5,190 tpy for Unit 1 and 5,372 tpy for Unit 2 based on the average of 2006-2008 actual emissions. A summary of the State's NO_x BART analysis and the visibility impacts is provided in Tables 12 and 13 below. The emission rate for each control option in the tables is reflective of the 30-day rolling average contained in the State's BART analysis. Due to the very small percent control achieved with combustion control refinements and neural network systems, the State did not perform visibility modeling for these two control options. Thus, Tables 12 and 13 do not show a value for visibility improvement for these options.

Table 12 – Summary of Craig Unit 1 NO_x BART Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu) (30-day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98th Percentile Impact)
Combustion Control	2	0.31	104	$122,000	$1,175	--

[16] Although not reflected in the SIP, the State's five-factor analysis in Appendix C of the SIP contains information on combustion control refinements and neural network systems.

Refinements						
Neural Network System	5	0.30	260	$280,000	$1,079	--
SNCR	15	0.27	779	$3,797,000	$4,877	0.31
SCR	74.9	0.08	3,893	$25,036,709	$6,432	1.01

Table 13 – Summary of Craig Unit 2 NO_x BART Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu) (30-day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98^{th} Percentile Impact)
Combustion Control Refinements	2	0.31	104	$122,000	$1,136	--
Neural Network System	5	0.30	260	$280,000	$1,043	--
SNCR	15	0.27	779	$3,797,000	$4,712	0.31
SCR	74	0.07	3,893	$25,036,709	$6,299	1.01

The State determined that SNCR was reasonable for BART for both Unit 1 and Unit 2 based on the cost effectiveness and visibility improvement associated with this level of control. The State determined SCR was not reasonable because of the high cost effectiveness value. Based upon its consideration of the five factors, the State determined that the NO_x BART emission limit for Craig Unit 1 is 0.27 lb/MMBtu (30-day rolling average) and for Unit 2 is 0.27 lb/MMBtu (30-day rolling average). The State assumed that the BART emission limits can be achieved through the operation of SNCR. We agree with the State's BART determination that an emission limit of 0.27 lb/MMBtu is NO_x BART for Craig Unit 1 and Unit 2. The State arrived at this limit based on a reasonable consideration of the five factors.

Although the State determined that 0.27 lb/MMBtu was NO_x BART for Craig Unit 1 and Unit 2, the State adopted a more stringent emission limit for Craig Unit 2 in its SIP and a slightly less stringent limit for Unit 1. Tri-State and the State agreed to a NO_x emissions control plan for Craig Unit 1 and Unit 2 that is more stringent overall. It consists of emission limits associated with the operation of SNCR for Unit 1 and the operation of SCR for Unit 2. These NO_x emission limits are 0.28 lb/MMBtu (30-day rolling average) for Craig Unit 1 and 0.08 lb/MMBtu (30-day rolling average) for Craig Unit 2. The State adopted these emission limits in its SIP, and these are the emission limits Tri-State must meet for purposes of the RH program. We are proposing to approve the State's NO_x emission limits for Craig Unit 1 and for Craig Unit 2 as satisfying the requirements of 40 CFR 51.308(e).

PM BART Determination

Craig Units 1 and 2 are each equipped with fabric filter baghouses to control PM emissions with an emission limit of 0.03 lb/MMBtu. Stack tests show that the fabric filter baghouses are achieving a 99% reduction in PM. Fabric filter baghouses are the most stringent control technology for controlling PM emissions. The State also evaluated what would constitute the most stringent level of control for PM by looking at recent BACT determinations. Based on this evaluation, the State determined that an emission limit of 0.03 lb/MMBtu represents the most stringent level of control for this type of source. Consistent with the BART Guidelines, the State did not provide a full five-factor analysis because the State determined BART to be the most stringent control technology and limit. The State determined that the PM BART emission limit is 0.03 lb/MMBtu (30-day rolling average) at Craig Unit 1 and Craig Unit 2. The State assumes the BART emission limits can be met through the operation of the current fabric filter baghouses.

We agree with the State's conclusions, and we are proposing to approve its PM BART determinations for Craig Unit 1 and Unit 2.

v. PSCO Hayden Station Units 1 and 2

Background

The Hayden facility is located four miles east of Hayden, Colorado in Routt County. This facility consists of two steam driven turbine/generator units, Units 1 and 2, and the associated equipment needed for generating electricity. Unit 1 is a pulverized-coal front-fired dry-bottom boiler, firing coal, with natural gas and No. 2 fuel oil used for startup, shutdown, and/or flame stabilization. Unit 2 is a pulverized-coal tangentially-fired dry-bottom boiler, firing coal, with No. 2 fuel oil used for startup, shutdown, and/or flame stabilization. Units 1 and 2 are the only subject-to-BART units at the facility. The State's BART determination for Hayden Units 1 and 2 can be found in Chapter 6.4.3.5 and Appendix C of the SIP.

SO_2 BART Determination

PSCO Hayden Units 1 and 2 are currently controlled with LSDs. Both units have a current SO_2 emission limit of 0.16 lb/MMBtu (30-day rolling average) and a requirement to achieve an 82% reduction of SO_2 (30-day rolling average). As mentioned earlier, if a BART source has current SO_2 controls achieving at least 50% control, then the state needs to evaluate upgrades to the existing control technology but does not need to consider the replacement of that technology. The State's BART analysis evaluated numerous LSD upgrades including: 1) use of performance additives; 2) use of more reactive sorbent; 3) increasing the pulverization level of sorbent; 4) engineering redesign of atomizer or slurry injection system (including an additional scrubber vessel); and 5) additional equipment and maintenance. The State determined that the application of the first three upgrades in the list above would not result in lower SO_2 emissions. The State determined that engineering redesign using an additional scrubber vessel and additional equipment and maintenance were technically feasible and would potentially achieve SO_2 emissions reductions.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, nor are there any remaining-useful-life issues for this source. Baseline SO_2 emissions are 1,172 tpy for Unit 1 and 1,469 tpy for Unit 2 based on the average of 2006-2008 actual emissions. A summary of the State's SO_2 BART analysis and the visibility impacts is provided in Tables 14 and 15 below. The emission rate for each control option in the tables is reflective of the 30-day rolling average contained in the State's BART analysis.

Table 14 – Summary of Hayden Unit 1 SO_2 BART Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu) (30-day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98th Percentile Impact)
Additional Equipment and Maintenance	5.2	0.13	61	$141,150	$2,317	.10
Additional Scrubber Vessel	41.7	0.08	488	$4,142,538	$8,490	0.14

Table 15 – Summary of Hayden Unit 2 SO_2 BART Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu) (30-day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98th Percentile Impact)
Additional Equipment and Maintenance	2.7	0.13	39	$141,150	$3,626	0.21
Additional Scrubber Vessel	40.1	0.08	589	$4,808,896	$8,164	0.26

The State determined that the cost of an additional scrubber vessel was not reasonable for BART controls. The State determined that additional equipment and maintenance was reasonable for SO_2 BART controls and that a more stringent 30-day rolling SO_2 limit represents an appropriate level of emissions control for BART for Hayden Units 1 and 2. Based on its consideration of the five factors, the State has determined that the SO_2 BART emission limit for Hayden Unit 1 is 0.13 lb/MMBtu (30-day rolling average) and for Unit 2 is 0.13 lb/MMBtu (30-day rolling average). The State assumes the BART emission limit can be met with the operation of the existing LSD.

We agree with the State's conclusions, and we are proposing to approve its SO_2 BART determinations for Hayden Unit 1 and Unit 2.

NO_x BART Determination

Hayden Units 1 and 2 are currently controlled with LNBs plus OFA, achieving emission reductions of 54 percent and 33 percent, respectively. The State determined that upgrades to the existing LNBs, SNCR, and SCR were technically feasible. The State determined that ECO, RRI, ROFA, and coal reburn plus SNCR were not technically feasible. The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, nor are there any remaining-useful-life issues for this source. Baseline NO_x emissions are 3,750 tpy for Unit 1 and 3,743 tpy for Unit 2 based on the average of 2006-2008 actual emissions. A summary of the State's NO_x BART analysis and the visibility impacts is provided in Tables 16 and 17 below. The emission rate for each control option in the tables is reflective of the 30-day rolling average contained in the State's BART analysis.

Table 16 – Summary of Hayden Unit 1 NO_x BART Analysis

Control	Control	Emission	Emission	Annualized	Cost	Visibility

Technology	Efficiency (%)	Rate (lb/MMBtu) (30-day Rolling Average)	Reduction (tpy)	Costs	Effectiveness ($/ton)	Improvement (Delta dv for the Maximum 98th Percentile Impact)
LNBs	37	0.30	1,391	$572,010	$411	0.69
SNCR	37	0.30	1,391	$1,353,500	$973	0.69
SCR	83	0.08	3,120	$10,560,612	$3,385	1.12

Table 17 – Summary of Hayden Unit 2 NO_x BART Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu) (30-day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98th Percentile Impact)
LNBs	35	0.24	1,303	$992,729	$762	0.40
SNCR	43	0.21	1,610	$1,893,258	$1,176	0.48
SCR	81	0.07	3,032	$12,321,491	$4,064	0.85

Based on its consideration of the five factors, the State has determined that the NO_x BART emission limit for Hayden Unit 1 is 0.08 lb/MMBtu (30-day rolling average) and for Unit 2 is 0.07 lb/MMBtu (30-day rolling average). The State assumes the BART emission limit can met through the installation and operation of SCR.

We agree with the State's conclusions, and we are proposing to approve its NO_x BART determinations for Hayden Unit 1 and Unit 2.

PM BART Determination

Hayden Units 1 and 2 are each equipped with fabric filter baghouses to control PM emissions with an emission limit of 0.03 lb/MMBtu. Stack tests show that the fabric filter baghouses are achieving a 99% reduction in PM. Fabric filter baghouses are the most stringent control technology for controlling PM emissions. The State also evaluated what would constitute the most stringent level of control for PM by looking at recent BACT determinations.

Based on this evaluation, the State determined that an emission limit of 0.03 lb/MMBtu represents the most stringent level of control for this type of source. Consistent with the BART Guidelines, the State did not provide a full five-factor analysis because the State determined BART to be the most stringent control technology and limit. The State has determined that the PM BART emission limit is 0.03 lb/MMBtu (30-day rolling average) for Hayden Unit 1 and Unit 2. The State assumes the BART emission limit can be met through the operation of the current fabric filter baghouses.

We agree with the State's conclusions, and we are proposing to approve its PM BART determinations for Hayden Unit 1 and Unit 2.

vi. CSU Martin Drake Units 5, 6, and 7

Background

The CSU's Martin Drake facility is located in Colorado Springs, Colorado. This facility consists of three steam driven turbine/generator units, Units 5, 6, and 7, and the associated equipment needed for generating electricity. Units 5, 6, and 7 are the only BART-eligible units at the facility. These units fire coal as the primary fuel and use natural gas for backup and startup. All three boilers are pulverized-coal, dry-bottom, front-fired boilers. The State's BART determination for CSU Martin Drake can be found in Chapter 6.4.3.6 and Appendix C of the SIP.

SO_2 BART Determination

Martin Drake Units 5, 6, and 7 are currently uncontrolled for SO_2. The State determined that DSI was technically feasible for all three units and that dry FGD was technically feasible for Units 6 and 7. The State determined dry FGD was not technically feasible for Unit 5 because of space constraints surrounding this unit. The State also examined emission limit tightening based on current operations for Unit 5.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, nor are there any remaining-useful-life issues for this source. Baseline SO_2 emissions are 1,269 tpy for Unit 5, 2,785 tpy for Unit 6, and 4,429 tpy for Unit 7 based on an average of 2006-2008 actual emissions. A summary of the State's SO_2 BART analysis and the visibility impacts is provided in Tables 18, 19, and 20 below. The emission rate for each control option in the tables is reflective of the 30-day rolling average contained in the State's BART analysis.

Table 18 – Summary of Martin Drake Unit 5 SO_2 BART Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu) (30-day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98th Percentile Impact)
DSI	60	0.26	762	$1,340,663	$1,760	0.12

Table 19 – Summary of Martin Drake Unit 6 SO_2 BART Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu) (30-day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98th Percentile Impact)
DSI	60	0.34	1,671	$2,234,438	$1,741	0.18
Dry FGD	82	0.15	3,632	$6,186,854	$2,709	0.24
Dry FGD	85	0.13	2,368	$6,647,835	$2,808	0.25
Dry FGD	90	0.09	2,507	$7,452,788	$4,064	0.26

Table 20 – Summary of Martin Drake Unit 7 SO_2 BART Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu) (30-day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98th Percentile Impact)
DSI	60	0.35	2,657	$3,732,826	$1,405	0.29

Dry FGD	82	0.16	3,632	$8,216,863	$2,263	0.39
Dry FGD	85	0.13	3,764	$8,829,321	$2,345	0.40
Dry FGD	90	0.09	3,986	$9,898,382	$2,483	0.41

The State also examined emission limits tightening based on current operations for Unit 5. (The State did not evaluate emissions limit tightening on Units 6 and 7 because the State determined BART to be the most stringent control technology). In order to evaluate emissions limit tightening, the State analyzed actual emission data for Unit 5 from the baseline period of 2006 – 2008. The State found that the maximum 30-day rolling emission rate for Unit 5 was 0.83 lb/MMBtu. The State applied a 5 percent buffer to the maximum 30-day rolling emission rate because the Drake facility has limited coal storage capacity and blends four different types of coals. These factors can lead to a greater fluctuation in emissions. Assuming no new control technology for Unit 5 and a 5 percent buffer, the State determined that an appropriate SO_2 emission limit would be 0.9 lb/MMBtu on a 30-day rolling average, which is less control than would be achieved with DSI.

Based upon its consideration of the five factors, the State determined that the following are the SO_2 BART limits for Drake Units 5, 6, and 7: 0.26 lb/MMBtu (30-day rolling average) for Unit 5; 0.13 lb/MMBtu (30-day rolling average) for Unit 6; and 0.13 lb/MMBtu (30-day rolling average) for Unit 7. The State assumes the BART emission limits can be met with the installation and operation of DSI on Unit 5 and the installation and operation of dry FGD on Unit 6 and Unit 7. The State determined that a lower emissions limit (0.09 lb/MMBtu) for Units 6 and 7 was not reasonable because the increased control costs to achieve such an emissions limit would not provide significant improvements in visibility (0.01 delta dv for each unit respectively).

We agree with the State's conclusions, and we are proposing to approve its SO_2 BART determinations for Martin Drake Unit 5, Unit 6, and Unit 7.

NO_x BART Determination

Martin Drake Units 5, 6, and 7 are currently controlled with LNBs achieving 54.7%, 52.8%, and 57.7% control, respectively. The State's BART analysis shows that OFA, ULNBs, ULNBs plus OFA, SNCR, SNCR plus ULNBs, and SCR are technically feasible for reducing NO_x emissions at Drake Units 5, 6 and 7. The State determined that RRI, ECO, and coal reburn plus SNCR were technically infeasible.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, nor are there any remaining-useful-life issues for this source. Baseline NO_x emissions are 768 tpy for Unit 5, 1,413 tpy for Unit 6, and 2,081 tpy for Unit 7 based on an average of 2006-2008 actual emissions. A summary of the State's NO_x BART analysis and the visibility impacts is provided in Tables 21, 22, and 23 below. The emission rate for each control option in the tables is reflective of the 30-day rolling average contained in the State's BART analysis.

Table 21 – Summary of Martin Drake Unit 5 NO_x BART Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu) (30-day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98^{th} Percentile Impact)
OFA	20	0.35	154	$141,844	$923	0.07
ULNBs	26	0.32	200	$147,000	$736	0.08
ULNBs + OFA	28	0.31	215	$288,844	$1,342	0.08
SNCR	30	0.30	231	$1,011,324	$4,387	0.08
ULNB/SCR layered approach	81.5	0.08	626	$4,467,000	$7,133	0.12
SCR	81.5	0.08	626	$4,580,349	$7,314	0.12

Table 22 – Summary of Martin Drake Unit 6 NO_x BART Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu) (30-day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98th Percentile Impact)
OFA	20	0.38	283	$104,951	$371	0.18
SNCR	30	0.33	424	$1,208,302	$2,851	0.19
ULNBs	32	0.32	452	$232,800	$515	0.20
ULNBs + OFA	36	0.31	509	$337,751	$664	0.19
ULNB/SCR layered approach	83	0.08	1,175	$6,182,800	$5,260	0.27
SCR	83	0.08	1,175	$6,340,797	$5,395	0.27

Table 23 – Summary of Martin Drake Unit 7 NO_x Bart Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu) (30-day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98th Percentile Impact)
OFA	20	0.36	416	$75,217	$181	0.22
SNCR	28	0.33	583	$386,000	$662	0.24
ULNBs	30	0.32	624	$2,018,575	$3,233	0.26
ULNBs + OFA	36	0.29	749	$461,217	$616	0.24
ULNB/SCR layered approach	80	0.08	1,709	$8,196,000	$4,797	0.37
SCR	80	0.08	1,709	$8,510,067	$4,981	0.37

The State determined that ULNBs plus OFA constitute BART based on the low dollars-per-ton control costs and the visibility improvement afforded by this control technology. The State did not choose SNCR as that technology provides a similar level of NO_x reduction and visibility improvement as ULNBs plus OFA, but at a higher cost per ton of pollutant removed. The State determined SCR was not cost effective for any of the units when compared with the visibility improvement.

Based upon its consideration of the five factors, the State determined that the following are the NO_x BART limits for Drake Units 5, 6, and 7: 0.31 lb/MMBtu (30-day rolling average) for Unit 5 and Unit 6; and 0.29 lb/MMBtu (30-day rolling average) for Unit 7. The State assumes that the BART emission limits can be achieved through the installation and operation of ULNBs plus OFA.

We agree with the State's conclusions, and we are proposing to approve the State's NO_x BART determinations for Martin Drake Units 5, 6, and 7.

PM BART Determination

Martin Drake Units 5, 6, and 7 are each equipped with fabric filter baghouses to control PM emissions with an emission limit of 0.03 lb/MMBtu. Stack tests show that the fabric filter baghouses are achieving a 95% reduction in PM. Fabric filter baghouses are the most stringent control technology for controlling PM emissions. The State also evaluated what would constitute the most stringent level of control for PM by looking at recent BACT determinations. Based on this evaluation, the State determined that an emission limit of 0.03 lb/MMBtu represents the most stringent level of control for this type of source. Consistent with the BART Guidelines, the State did not provide a full five-factor analysis because the State determined BART to be the most stringent control technology and limit.

The State has determined that 0.03 lb/MMBtu (30-day rolling average) is the PM BART limit for Martin Drake Units 5, 6, and 7. The State assumes the limits can be met with the operation of the current fabric filter baghouses.

We agree with the State's conclusions, and we are proposing to approve its PM BART determinations for Martin Drake Units 5, 6, and 7.

Summary of Colorado's BART Determinations

Table 24 provides a summary of the State's BART determinations that we are proposing to approve.

Table 24 – Summary of the State's BART Determinations EPA is Proposing to Approve

Emission Unit	Assumed NO_x Control Type	NO_x Emission Limit	Assumed SO_2 Control Type	SO_2 Emission Limit	Assumed Particulate Control and Emission Limit
Cemex - Lyons Kiln	SNCR	255.3 lbs/hr (30-day rolling average) 901.0 tpy (12-month rolling average)	None	25.3 lbs/hr (12-month rolling average) 95.0 tpy (12-month rolling average)	Fabric Filter Baghouse * 0.275 lb/ton of dry feed 20% opacity
Cemex - Lyons Dryer	None	13.9 tpy	None	36.7 tpy	Fabric Filter Baghouse* 22.8 tons/yr 10% opacity
CENC Unit 4	LNBs with OFA	0.37 lb/MMBtu (30-day rolling average) Or 0.26 lb/MMBtu Combined Average for Units 4 & 5 (30-day rolling average)	None	1.0 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.07 lb/MMBtu
CENC Unit 5	LNBS with SOFA and SNCR	0.19 lb/MMBtu (30-day rolling average) Or 0.26 lb/MMBtu Combined Average for Units 4 & 5 (30-day rolling average)	None	1.0 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.07 lb/MMBtu

Comanche Unit 1	LNBs*	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	Lime Spray Dryer*	0.12 lb/MMBtu (30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Comanche Unit 2	LNBs*	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	Lime spray Dryer*	0.12 lb/MMBtu (30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 1	SNCR	0.28 lb/MMBtu (30-day rolling average)	Wet Limestone scrubber*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 2	SCR	0.08 lb/MMBtu (30-day rolling average)	Wet Limestone scrubber*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Hayden Unit 1	SCR	0.08 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Hayden Unit 2	SCR	0.07 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Martin Drake Unit 5	ULNBs with OFA	0.31 lb/MMBtu (30-day rolling average)	Dry Sorbent Injection	0.26 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Martin Drake Unit 6	ULNBs with OFA	0.31 lb/MMBtu	Lime Spray Dryer or	0.13 lb/MMBtu	Fabric Filter Baghouse*

		(30-day rolling average)	Equivalent Control Technology	(30-day rolling average)	0.03 lb/MMBtu
Martin Drake Unit 7	ULNBs with OFA	0.29 lb/MMBtu (30-day rolling average)	Lime Spray Dryer or Equivalent Control Technology	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu

*Indicates controls that are already installed

vii. PSCO BART Alternative

Colorado has adopted the PSCO BART Alternative Program (BART alternative) to meet the requirements for BART for PSCO Cherokee Unit 4, Valmont Unit 5, and Pawnee Station Unit 1 and RP for PSCO Arapahoe Units 3 and 4 and Cherokee Units 1, 2, and 3. Under 40 CFR 51.308(e)(2), states may choose to meet the BART requirements with a BART alternative. Section 51.308(e)(2)specifies the requirements that a state must meet to show that the alternative measure or alternative program achieves greater RP than would be achieved through the installation and operation of BART. Section 51.308(e)(3) contains additional requirements that states must address pertaining to their alternative program. Table 25 provides a summary of the units covered under the BART alternative, as well as the required control or shutdown date for the facility.

Table 25 – Sources Covered Under the PSCO BART Alternative

Unit	BART Eligible?	NO_x Control Type	NO_x Emission Limit	SO_2 Control Type	SO_2 Emission Limit	Particulate Type And Limit
Cherokee Unit 1	No	Shutdown by 7/1/2012	0	Shutdown by 7/1/2012	0	Shutdown by 7/1/2012
Cherokee Unit 2	No	Shutdown by 12/31/2011	0	Shutdown by 12/31/2011	0	Shutdown by 12/31/2011
Cherokee Unit 3	No	Shutdown by 12/31/2016	0	Shutdown by 12/31/2016	0	Shutdown by 12/31/2016

Cherokee Unit 4	Yes	Natural Gas Operation by 12/31/2017	0.12 lb/MMBtu (30-day rolling average) by 12/31/2017	Natural Gas Operation by 12/31/2017	7.81 tpy (12 month rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Valmont Unit 5	Yes	Shutdown by 12/31/2017	0	Shutdown by 12/31/2017	0	Shutdown by 12/31/2017
Pawnee Unit 1	Yes	SCR**	0.07 lb/MMBtu (30-day rolling average) by 12/31/2014	Lime Spray Dryer**	0.12 lb/MMBtu (30-day rolling average) by 12/31/2014	Fabric Filter Baghouse* 0.03 lb/MMBtu
Arapahoe Unit 3	No	Shutdown by 12/31/2013	0	Shutdown by 12/31/2013	0	Shutdown by 12/31/2013
Arapahoe Unit 4	No	Natural Gas Operation by 12/31/2014	600 tpy (12 month rolling average) by 12/31/2014	Natural Gas operation by 12/31/2014	1.28 tpy (12 month rolling average) by 12/31/2014	Fabric Filter Baghouse* 0.03 lb/MMBtu

*Controls are already installed

** The State assumes this is the control technology the source will use to meet the limit.

A summary of Colorado's BART alternative and the requirements under 40 CFR 51.308(e)(2) and (e)(3) are discussed below. The State's analysis of the PSCO BART alternative can be found in Chapter 6.4.3.7 of the SIP.

i. A list of all BART-eligible sources

Pursuant to 40 CFR 51.308(e)(2)(i)(A), the State included a list of all BART-eligible sources in the State in Chapter 6, Table 6-3 of the SIP. A list of BART-eligible sources can also be found in Table 2 of this notice.

ii. A list of all sources covered by the alternative

Pursuant to 40 CFR 51.308(e)(2)(i)(B), the State included in the SIP a list of the BART-eligible sources that are included in the BART alternative, as well as the RP sources covered under the program.

iii. Best system of continuous emission control technology

As required by 40 CFR 51.308(e)(2)(i)(C), the State determined the best system of continuous emission control for sources that are subject to BART and that are covered by the BART alternative program. Because the State's BART alternative program was designed to meet requirements other than BART,[17] our regulation allowed the State to use simplifying assumptions to determine the best system of continuous emission control for the BART sources in the State's BART alternative program. 40 CFR 51.308(e)(2)(i)(C); 71 FR 60619. We have indicated that our BART presumptive limits for SO_2 and NO_x, set forth in our BART Guidelines (70 FR 39171-39172), represent appropriate simplifying assumptions for determining the best system of continuous emission control for EGUs. The presumptive limit for SO_2 is 0.15 lb/MMBtu. The presumptive limits for NO_x vary depending on boiler and coal type. The State used the presumptive limits in the BART Guidelines for calculating the best system of continuous emission control for the BART sources in the State's BART alternative program. The State also used the presumptive limits as a benchmark for control levels that might have been anticipated from the non-BART sources that are included in the BART alternative, if the State had not adopted the BART alternative.

iv. Projected emissions reductions

Pursuant to 40 CFR 51.308(e)(2)(i)(D), the State provided a calculation of the emission reductions expected from the BART alternative compared to emissions reductions that would be

[17] Specifically, the program was designed to help the State achieve its overarching reasonable progress goals and to meet the requirements of Colorado House Bill 10-1365 and §40-3.2-202, C.R.S. - Colorado's Clean Air - Clean Jobs Act.

achieved by the application of the presumptive limits to sources covered under the alternative. Tables 26 and 27 show the relative emissions.

Table 26 – SO_2 Reductions under the BART Alternative

Unit	SO_2 Average Emissions 2006-2008 (tpy)	SO_2 Emissions with Presumptive Limits (0.15 lb/MMBtu)	SO_2 Emissions under BART Alternative in 2018 (tpy)
Arapahoe Unit 3	924.97	328.51	0.00
Arapahoe Unit 4	1,764.70	640.93	1.28
Cherokee Unit 1	2,220.80	623.35	0.00
Cherokee Unit 2	1,888.37	418.95	0.00
Cherokee Unit 3	743.00	611.99	0.00
Cherokee Unit 4	2,135.43	1,953.57	7.81
Valmont Unit 5	758.47	1,029.19	0.00
Pawnee Unit 1	13,472.07	3,007.03	2,405.63
Total	23,908	8,614	2,415

Table 27 – NO_x Reductions under the BART Alternative

Unit	NO_x Average Emissions 2006-2008 (tpy)	NO_x Presumptive Limit (lb/MMBtu)	NO_x Emissions with Presumptive Limits (tpy)	NO_x Emissions under BART Alternative in 2018 (tpy)
Arapahoe Unit 3	1,770.47	0.23	503.71	0.00
Arapahoe Unit 4	1,147.67	0.23	982.77	900.00
Cherokee Unit 1	1,556.23	0.39	1,620.71	0.00
Cherokee Unit 2	2,895.20	0.39	1,089.27	0.00
Cherokee Unit 3	1,865.50	0.39	1,591.18	0.00
Cherokee Unit 4	4,274.00	0.28	3,646.67	2,062.86
Valmont Unit 5	2,313.73	0.28	1,921.15	0.00
Pawnee Unit 1	4,537.73	0.23	4,610.78	1,403.28
Total	20,361		15,996	4,366

v. Evidence that the alternative program achieves greater RP than BART

Tables 26 and 27 demonstrate that the State's BART Alternative achieves greater RP than would be achieved through the installation of BART. By applying presumptive limits to the sources, the resulting emissions would be 8,614 tpy for SO_2 and 15,996 tpy for NO_x. Under the BART alternative, the emissions from the sources in 2018 will be 2,415 tpy for SO_2 and 4,366 tpy for NO_x. Thus, EPA concludes that the BART alternative achieves greater RP than would be achieved through the installation of BART and meets the requirements of 40 CFR 51.308(e)(2)(i)(E).

vi. All emission reductions take place during first planning period

Pursuant to 40 CFR 51.308(e)(2)(ii), Table 25 shows that all controls under the BART alternative will occur by December 17, 2017, within the first planning period, which ends in December 2018.

vii. Reductions are surplus

As required by 40 CFR 51.308(e)(2)(iv), the State has concluded that emission controls associated with the BART alternative have not been used for other SIP purposes and are only a requirement under the RH SIP. The State has thus determined they are surplus. EPA agrees with the State's assessment.

viii. Distribution of emissions

The State has determined that the distribution of emissions under the BART alternative is not substantially different than under source-by-source BART or RP. The BART alternative includes only sources that are BART or RP sources and does not include any sources that would not have been included in the RH SIP. All of the units in the BART alternative are located within or adjacent to the 8-hour ozone non-attainment area in the Front Range of Colorado. Pursuant to 40 CFR 51.308(e)(3), since the State has determined that the geographic distribution of emissions is not substantially different under the alternative program, the State is not required to perform visibility modeling. We agree that the BART alternative will not result in a significant shift in the distribution of emissions.

EPA is proposing to approve the State's BART alternative as it meets the requirements for alternative programs under 40 CFR 51.308(e)(2) and (e)(3).

D. Reasonable Progress Requirements

In order to establish RPGs for its Class I areas, and to determine the controls needed for the long-term strategy, Colorado followed the process established in the RHR. First, Colorado identified the anticipated visibility improvement in 2018 in all its Class I areas using the WRAP Community Multi-Scale Air Quality (CMAQ) modeling results. This modeling identified the extent of visibility improvement from the baseline by pollutant for each Class I area. The modeling relied on projected source emission inventories, which included enforceable federal and state regulations already in place and anticipated BART controls.

Colorado then identified sources and source categories (other than BART sources) in Colorado that are major contributors to visibility impairment and considered whether these sources should be controlled based on a consideration of the factors identified in the CAA and EPA's regulations. *See* CAA 169A(g)(1) and 40 CFR 51.308(d)(1)(i)(A).

The SIP includes Colorado's analysis and conclusion that reasonable progress will be made by 2018, including an analysis of pollutant trends, emission reductions, and improvements expected. The RP discussion and analyses are included in Chapter 8 and Appendix D of the SIP. We are proposing to approve Colorado's submitted RP goals as described more fully below.

1. Visibility Impairing Pollutants and Sources

a. Source Regions of Pollutants

In order to determine the significant sources contributing to haze in Colorado's Class I areas, Colorado relied upon two source apportionment analysis techniques developed by the WRAP. The first technique was regional modeling using the Comprehensive Air Quality Model (CAMx) and the PM Source Apportionment Technology (PSAT) tool, used for the attribution of sulfate and nitrate sources only. The second technique was the Weighted Emissions Potential (WEP) tool, used for attribution of sources of OC, EC, $PM_{2.5}$, and PM_{10}. The WEP tool is based on emissions and residence time, not modeling.

PSAT uses the CAMx air quality model to show nitrate-sulfate-ammonia chemistry and apply this chemistry to a system of tracers or "tags" to track the chemical transformations, transport, and removal of NO_x and SO_2. These two pollutants are important because they tend to originate from anthropogenic sources. Therefore, the results from this analysis can be useful in determining contributing sources that may be controllable, both in-state and in neighboring states.

WEP is a screening tool that helps to identify source regions that have the potential to contribute to haze formation at specific Class I areas. Unlike PSAT, this method does not account for chemistry or deposition. The WEP combines emissions inventories, wind patterns, and residence times of air masses over each area where emissions occur, to estimate the percent contribution of different pollutants. Like PSAT, the WEP tool compares baseline values (2000-2004) to 2018 values, to show the improvement expected by 2018, for sulfate, nitrate, OC, EC, $PM_{2.5}$, and PM_{10}. More information on the WRAP modeling methodologies is available in the document *Technical Support Document for Technical Products Prepared by the Western Regional Air Partnership (WRAP) in Support of Western Regional Haze Plans* in the Supporting and Related Materials section of the docket. Table 28 shows Colorado's contribution to extinction at its own Class I areas. Sulfate and nitrate contribution is based on PSAT results and OC, EC, $PM_{2.5}$, PM_{10}, and sea salt contributions are based on WEP.

Table 28 - Colorado Sources Extinction Contribution 2000-2004 for 20% Worst Days

Class I Area	Pollutant Species	2000-2004 Extinction (Mm^{-1})	Species Contribution to Total Extinction (%)	CO Sources Contribution to Species Extinction (%)[1]
GRSA1(Great Sand Dunes National park and Preserve)	Sulfate	5.97	21.1	13.0
	Nitrate	1.96	6.9	14.7
	OC	8.47	30.0	34.8
	EC	1.74	6.2	39.1
	$PM_{2.5}$	2.81	10.0	34.9
	PM_{10}	7.24	25.6	37.7
	Sea Salt	0.05	0.2	Not modeled by the WRAP
MEVE1 (Mesa Verde National Park)	Sulfate	6.46	19.9	2.0
	Nitrate	2.30	7.1	10.4
	OC	12.28	37.8	35.4
	EC	2.37	7.3	35.4
	$PM_{2.5}$	2.51	7.7	19.0
	PM_{10}	6.52	20.1	15.3
	Sea Salt	0.04	0.1	Not modeled by the WRAP
MOZI1 (Mount Zirkel and Rawah Wilderness Area)	Sulfate	5.25	22.6	26.9
	Nitrate	2.16	9.3	39.7
	OC	9.94	42.7	90.7
	EC	1.76	7.6	87.9
	$PM_{2.5}$	0.98	4.2	51.8
	PM_{10}	3.15	13.5	48.5
	Sea Salt	0.02	0.1	Not modeled by the WRAP
RMHQ1 (Rocky Mountain National Park)	Sulfate	7.91	24.3	31.3
	Nitrate	5.26	16.2	37.8
	OC	10.51	32.3	77.4
	EC	2.56	7.9	77.1
	$PM_{2.5}$	1.37	4.2	49.9
	PM_{10}	4.90	15.1	52.2

	Sea Salt	0.01	0.0	Not modeled by the WRAP
WEMI1(Weminuche Wilderness, Black Canyon of the Gunnison, and La Garita Wilderness)	Sulfate	4.99	23.9	5.0
	Nitrate	1.21	5.8	5.0
	OC	8.29	39.7	47.7
	EC	2.01	9.6	45.1
	$PM_{2.5}$	1.26	6.0	20.7
	PM_{10}	2.99	14.3	18.4
	Sea Salt	0.13	0.6	
WHRI1 (Eagles Nest Wilderness, Flat Tops Wilderness, Maroon Bells – Snowmass Wilderness, and West Elk Wilderness)	Sulfate	4.79	24.3	6.5
	Nitrate	1.31	6.6	20.0
	OC	7.83	39.7	60.6
	EC	1.76	8.9	61.1
	$PM_{2.5}$	1.18	6.0	39.7
	PM_{10}	2.82	14.3	35.8
	Sea Salt	0.02	0.1	Not modeled by the WRAP

Table 29 shows influences from sources both inside and outside of Colorado per the PSAT modeling for 2018. As indicated, boundary conditions or outside domain are the highest contributor to sulfate at all Colorado Class I areas. The boundary conditions represent the background concentrations of pollutants that enter the edge of the modeling domain. Depending on meteorology and the type of pollutant (particularly sulfate), these emissions can be transported great distances that can include regions such as Canada, Mexico, and the Pacific Ocean.

Colorado appears to be a major contributor of particulate sulfate at those Class I areas near significant sources of SO_2, specifically Rocky Mountain National Park, Mount Zirkel, and Rawah Wilderness. For nitrate, Colorado appears to be a major contributor at most of its Class I areas except for the Weminuche Wilderness, La Garita Wilderness, and Black Canyon of Gunnison National Park. Boundary conditions are also a major contributor of nitrate at all Colorado Class I areas.

Table 29 – PSAT Source Region Apportionment for 20% Worst Days

Class I Area		2018 Sulfate PSAT				2018 Nitrate PSAT			
GRSA1 (Great Sand Dunes National Park and Preserve)	**Region**[18]	OD	CO	NM	MEX	OD	NM	CO	CEN
	% Contribution	38.2	9.7	8.1	7.9	28.9	27.2	12.3	8.8
MEVE1 (Mesa Verde National Park)	**Region**	OD	NM	MEX	AZ	NM	CO	OD	AZ
	% Contribution	35.4	17.2	11.3	10.2	60.2	12.3	9.7	9.7
MOZI1 (Mount Zirkel and Rawah Wilderness Area)	**Region**	OD	CO	WY	UT	CO	OD	UT	WY
	% Contribution	29.3	20.9	9.2	7.6	41.6	17.8	14.1	10.3
RMHQ1 (Rocky Mountain National Park)	**Region**	OD	CO	WY	CEN	CO	OD	WY	UT
	% Contribution	29.1	23.5	7.7	7.2	33.7	15.8	11.0	5.9
WEMI1(Weminuche Wilderness, Black Canyon of the Gunnison, and La Garita Wilderness)	**Region**	OD	NM	MEX	PO	NM	OD	CA	AZ
	% Contribution	34.9	13.2	10.7	9.1	43.7	19.7	14.1	9.9
WHRI1 (Eagles Nest Wilderness, Flat Tops Wilderness, Maroon Bells – Snowmass Wilderness, and West Elk Wilderness)	**Region**	OD	MEX	AZ	NM	OD	UT	CO	NM
	% Contribution	40.1	10.8	6.8	6.1	55.0	20.0	15.0	10.0

b. Source Categories

The State conducted a detailed evaluation of six visibility impairing pollutants: nitrates,

[18] OD denotes Outside Domain; MEX denotes the country of Mexico; CEN denotes the Central Regional Air Partnership; PO denotes Pacific Offshore.

sulfates, OC, EC, fine soil and coarse mass (CM) (fine soil and CM are collectively known as PM) contributing to visibility impairment at Colorado's Class I areas.[19] The State relied on WRAP emission inventory information and modeling to determine what pollutants and sources were contributing to visibility impairment at its Class I areas. Once the State determined what sources were contributing to visibility impairment and by what amount, it determined whether the source/source category was significant and if it was reasonable to control.

Based on its analysis, the State determined that the sources of OC, EC, and area source PM are not well documented because of emission inventory limitations associated with natural sources (predominantly wildfires), uncertainty of windblown emissions, and poor model performance for these constituents. The State determined it would defer on addressing these pollutants until science and emission inventories are improved for consideration in future RH SIPs. The State determined that RP controls would be evaluated for SO_2, NO_x, and stationary source PM.

The State's analysis evaluated the projected sources of SO_2 and NO_x in 2018. The State's analysis shows that 78% of 2018 total statewide SO_2 emissions are from point sources, mainly coal-fired boilers. Area source SO_2 emissions (14% of total SO_2 emissions) are mainly comprised of thousands of small commercial boilers and internal combustion engines spread throughout the State that burn distillate fuel. The State determined there is no practical way to control thousands of small boilers and engines. The State determined SO_2 emissions from natural fires constitute 6% of total SO_2 emissions and are considered uncontrollable. Both off-road and on-road mobile sources each constitute 1% of SO_2 emissions and are subject to federal ultra-low sulfur diesel fuel requirements that limit sulfur content to 15 ppm. Ultra-low sulfur

[19] See *Significant Source Categories Contributing to Regional Haze at Colorado Class I Areas*, October 2, 2007, located in the Supplemental and Related Materials section of the docket.

diesel fuel was in widespread use after June 2010 for off-road mobile sources and after June 2006 for on-road mobile sources. The State has determined that point sources are the dominant source of emissions and, for this planning period, the only practical category to evaluate under RP for SO_2.

Colorado's analysis shows that point sources comprise 36% of total NO_x emissions; these emissions are primarily from coal-fired external combustion boilers and natural gas-fired internal combustion engines (in oil and gas compression service). On-road and off-road mobile sources comprise 16% and 14% of Statewide NO_x emissions, respectively. Because mobile exhaust emissions are primarily addressed, and will continue to be addressed, through federal programs, the State did not evaluate mobile sources for RP control in this planning period. Emissions of NO_x from biogenic activity and natural fire are considered uncontrollable and vary from year-to-year. Non-oil and gas area sources comprise about 6% of NO_x emissions and involve thousands of combustion sources that the State determined are not reasonable to control in this planning period. Area oil and gas emissions contribute 12% of total NO_x emissions.

The State has determined that large point sources are the dominant source of NO_x emissions and are practical to evaluate under RP in this planning period. The State determined that smaller point sources (combustion turbines) and area oil and gas emissions, specifically heater-treaters and reciprocating internal combustion engines (RICE), significantly contribute to visibility impairment in Colorado's Class I areas and are also practical to evaluate for RP controls in this planning period.

c. Stationary Sources

The State used a RP screening methodology called "Q/d" to determine which stationary (point) sources would be candidates for controls under RP. The methodology Q/d is a calculated ratio that evaluates stationary source emissions (mathematical sum of actual SO_2, NO_x and PM emissions in tons per year, denoted as "Q") divided by the distance (in kilometers, denoted as "d") of the point source from the nearest Class I area. The State evaluated the visibility impact sensitivity of different Q/d thresholds and determined that a Q/d ratio equal to or greater than 20 approximated a delta dv impact ranging from 0.06 dv to 0.56 dv. The resultant average of the range is about 0.3 dv, which is a more conservative RP threshold than the 0.5 dv that was used in determining which sources would be subject-to-BART under the federal BART regulations. Since the threshold is more conservative than the subject-to-BART threshold, the State determined that a Q/d value of 20 is reasonable for determining which RP sources the State should consider for RP controls.

The evaluation of potential RP sources involved all Colorado stationary sources with actual SO_2, NO_x, or PM_{10} emissions over 100 tpy in 2007. The State identified 113 sources as exceeding the 100 tpy threshold for any of the three pollutants and further analyzed these sources using the Q/d analysis. The State determined that there were seven sources that had a Q/d equal to or greater than the threshold of 20 that were not already being controlled under BART.[20] The State deemed these seven sources to be subject to RP and the State completed a RP analysis for each of the sources.

Table 30 shows the subject-to-RP sources identified by the State.

Table 30 – RP Sources Evaluated for Controls

Source	Q (tpy based on 2007 Actual Emissions)	Nearest Class I Area	Q/d Value
Platte River Power Authority –	2,796	Rocky	49.9

[20] The State has concluded that it need not reanalyze a source for RP controls for which it has already made a BART determination. This conclusion is consistent with our RP guidance.

Rawhide Station		Mountain National Park	
CENC – Unit 3	4,453	Rocky Mountain National Park	81.7
CSU- Nixon Power Plant – Nixon Unit 1	6,668	Great Sand Dunes National Park	63.9
Black Hills Energy Clark Power Plant Units 1 and 2	2,393	Great Sand Dunes National Park	40.8
Holcim – Kiln and Dryer	3,250	Great Sand Dunes National Park	49.2
Tri-State – Nucla	3,327	Black Canyon National Park	47.1
Tri-State – Craig Unit 3	20,628	Flat Tops Wilderness Area	432.4
PSCO – Cameo Station	3,750	Black Canyon National Park	53.2

We agree with the State's analysis on appropriate source categories and stationary sources to be evaluated under RP.

2. Four Factor Analyses

In determining the measures necessary to make RP, states must take into account the following four factors and demonstrate how they were taken into consideration in selecting RP goals for a Class I area:

- Costs of Compliance;
- Time Necessary for Compliance;
- Energy and Non-air Quality Environmental Impacts of Compliance; and
- Remaining Useful Life of any Potentially Affected Sources. CAA § 169A(g)(1) and 40 CFR 308(d)(1)(i)(A).

The State performed a four factor analysis for each of the RP sources pursuant to 40 CFR 51.308(d)(1)(i)(A).

State NO_x Control Criteria

For potential NO_x controls in the RP context, the State adopted the same screening criteria as used to evaluate potential NO_x BART controls. For further detail, see section V.C.3 above. We have some of the same concerns regarding the use of these criteria for RP as we expressed concerning their use in BART determinations. Nonetheless, as discussed below, we agree with the State's determinations concerning NO_x controls on the RP sources.

SO_2 Controls – Wet and Dry Scrubbing

As it did in the BART context, the State eliminated wet FGD from consideration as a potential RP control for the same reasons - because of negative non-air quality environmental impact on water usage. EPA is proposing that the State has provided adequate justification to eliminate wet FGD as a potential SO_2 RP control.

a. Visibility Improvement Modeling

Colorado concluded that it is also appropriate to consider a fifth factor for evaluating potential RP control options - the degree of visibility improvement that may reasonably be anticipated from the use of the RP controls. Our RP guidance contemplates that states may be able to consider other relevant factors for RP sources (see EPA's *Guidance for Setting Reasonable Progress Goals under the Regional Haze Program,* ("Reasonable Progress Guidance"), pp. 2-3, July 1, 2007), and we find it appropriate to consider visibility improvement when evaluating potential RP controls.

For the RP modeling, the State followed the BART Guidelines. The BART Guidelines provide that states may use the CALPUFF modeling system or another appropriate model to determine the visibility improvement expected at a Class I area from the potential BART control technology applied to the source. Colorado performed CALPUFF modeling to determine the degree of visibility improvement expected at a Class I area based on the controls evaluated for RP for the subject-to-RP sources.

The BART Guidelines also recommend that states develop a modeling protocol for making individual source attributions, and suggest that states may want to consult with EPA and their RPO to address any issues prior to modeling. Colorado used the CALPUFF model for Colorado RP sources in accordance with a protocol it developed titled "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis, revised August 19, 2010," which was approved by EPA and is included in the Supplemental Information section of the docket. The Colorado protocol follows recommendations for long range transport described in appendix W to 40 CFR part 51, "Guideline on Air Quality Models," and in EPA's "Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts," as recommended by the BART Guidelines. (40 CFR part 51, appendix Y, section III.D.5).

b. Summary of RP Determinations and Limits

For the subject-to-RP sources, the State provided analyses that took into consideration the four factors as required by section 169A(g)(1) of the CAA. The State also included visibility improvement as a fifth factor in its RP analyses for most sources. The State elected to consider EPA's BART Guidelines as relevant to its RP evaluations, in addition to EPA's Reasonable Progress Guidance. A summary of the RP analysis for each source is included in Chapter 8 of the SIP. The State's complete RP analyses, as well as additional technical information and materials, are included in Appendix D of the SIP. EPA is proposing to approve the RP determinations submitted by the State for: Platte River Power Authority (PRPA), Rawhide Unit

101; CENC Unit 3; CSU Nixon Power Plant, Nixon Unit 1; Black Hills Energy Clark Power Plant, Units 1 and 2; Holcim Florence Cement Plant; Tri-State Generation, Nucla; Tri-State Generation, Craig Unit 3; and PSCO Cameo Station. A summary of the RP determination for each source is provided below.

i. Platte River Power Authority – Rawhide Unit 101

Background

The PRPA Rawhide Energy Station is located in Larimer County approximately 10 miles north of the town of Wellington, Colorado. Rawhide Unit 101 is a coal-fired steam-driven EGU with a rated electric generating capacity of 305 MW (gross). The Rawhide Station also has five natural-gas-fired combustion turbines. The primary use of these units is to meet PRPA's energy reliability and peak load requirements. The turbines operate on limited, intermittent, and unpredictable schedules as peak loading units. Additionally, the facility includes a number of fugitive dust sources. The State did not do a RP analysis for the turbines or fugitive dust sources since these units fall below the de minimis threshold established by the State.[21] Unit 101 is the only subject-to-RP unit at the facility. The State's RP determination can be found in Chapter 8.5.2.1 and Appendix D of the SIP.

SO_2 RP Determination

Rawhide Unit 101 is currently controlled with a dry FGD achieving over 72 percent SO_2 reduction with a current permit limit of 0.09 lb/MMBtu (annual average). Per the BART Guidelines, for EGUs with preexisting post-combustion SO_2 controls achieving removal

[21] For the purposes of evaluating RP, the State has elected to set de minimis thresholds for any emission unit at a subject-to-RP source with actual baseline emissions of SO2, NOx, or PM10 less than the federal Prevention of Significant Deterioration (PSD) significance levels. These de minimis levels are as follows: NOx – 40 tons per year; SO2 – 40 tons per year; PM10 – 15 tons per year. Any unit emitting below these levels is not subject to an RP analysis. The BART Guidelines allow for states to set de minimis levels (see 70 FR 39161), and we think it was reasonable for the State to set de minimis levels for RP sources.

efficiencies greater than 50 percent, states should consider cost effective scrubber upgrades designed to improve the system's overall SO_2 removal efficiency (70 FR 39171). Under the BART Guidelines, a state is not required to evaluate the replacement of the current SO_2 controls if the removal efficiency is over 50% (70 FR 39171). We conclude that it is reasonable to follow this approach for evaluating potential RP controls in this initial planning period. Colorado should consider replacement of existing scrubbers in future planning periods. The State's RP analysis evaluated numerous dry FGD upgrades including: 1) use of performance additives; 2) use of more reactive sorbent; 3) increase the pulverization level of sorbent; and 4) engineering redesign of atomizer or slurry injection system. The State analyzed each possible upgrade and determined that all were technically infeasible for Rawhide Unit 101. The State determined that fuel switching from coal to natural gas was a technically feasible option for Rawhide Unit 101.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, nor are there any remaining-useful-life issues for this source.

Baseline SO_2 emissions are 913 tpy based on an average of 2006-2008 actual emissions. A summary of the State's SO_2 RP analysis and the visibility impacts for fuel switching is provided in Table 31 below.

Table 31 – Summary of Rawhide Unit 101 SO_2 RP Analysis

Control Technology	Emission Rate (lb/MMBtu) (30-Day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98^{th} Percentile Impact)
Fuel Switching	0.00	906	$237,424,331	$262,169	0.87

The State determined it would take PRPA approximately 2-3 years to switch from coal to natural gas. The State determined fuel switching was not reasonable based on the high cost effectiveness value.

The State also assessed emissions limit tightening based on current operations. Rawhide Unit 101's average 30-day rolling emission rate during the baseline period (2006 - 2008) was 0.09 lb/MMBtu. The maximum 30-day rolling emission rate during this period was 0.11 lb/MMBtu. The State evaluated both these levels as potential emissions limits. The State also evaluated an emission limit of 0.07 lb/MMBtu. Emissions limit tightening to emissions levels currently achieved is a no-cost control option. The State modeled visibility improvement for SO_2 emission limits lower than 0.11 lb/MMBtu. The modeling showed that, compared to an emission limit of 0.11 lb/MMBtu, an emission limit of 0.09 lb/MMBtu would result in 0.01 dvs of visibility improvement, and an emission limit of 0.07 lb/MMBtu would result in 0.03 dvs of visibility improvement.

The State has determined that the SO_2 RP emission limit for Rawhide Unit 101 is 0.11 lb/MMBtu (30-day rolling average), reflecting the actual performance of the current controls. It represents a more stringent limit than the current limit of 0.13 lb/MMBtu (30-day rolling average). The State assumes the RP limit can be achieved by the operation of the current LSD. The State determined a lower SO_2 limit was not reasonable as it would not result in significant visibility improvement (less than 0.02 dv) and would likely result in frequent non-compliance events.

We agree with the State's conclusions, and we are proposing to approve its SO_2 RP determination for PRPA Rawhide Unit 101.

NO_x RP Determination

Rawhide Unit 101 is currently controlled with LNB+ close coupled over fire air + SOFA achieving a 49.6% control. The State determined that enhanced combustion controls (ECC), SNCR, fuel switching from coal to natural gas, and SCR were technically feasible NO_x controls for Rawhide Unit 101. The State determined that RRI, ECO, and coal reburn + SNCR were not technically feasible.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, nor are there any remaining-useful-life issues for this source. Baseline NO_x emissions are 1,866 tpy based on an average of 2006-2008 actual emissions. A summary of the State's NO_x BART analysis and the visibility impacts is provided in Table 32 below. The emission rate for each control option in the table is reflective of the 30-day rolling average contained in the State's RP analysis.

Table 32 – Summary of Rawhide Unit 101 NO_x RP Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu) (30-Day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98th Percentile Impact)
ECC	24	0.145	448	$288,450	$644	0.45
SNCR	27	0.140	504	$1,596,000	$3,168	0.46
Fuel Switching	29	0.135	545	$237,424,331	$435,681	0.47
SCR	63.5	.07	1,185	$12,103,000	$10,214	0.59

The State estimates that the time necessary for compliance after SIP approval would be approximately 2-3 years for SNCR and 3-4 years for SCR. ECC could be functional within 6 months of SIP approval.

The State eliminated switching to natural gas and SCR from consideration due to the high cost effectiveness values and associated degree of visibility improvement. The State determined that ECC was reasonable for RP control. The State made this determination based on the cost effectiveness and visibility improvement associated with ECC. SNCR would achieve similar emissions reductions to ECC and would afford a minimal additional visibility benefit (0.01 delta dv), but it would do so at a significantly higher dollar-per-ton control cost compared to the selected ECC. Thus, the State determined that SNCR was not reasonable. Based upon its consideration of the five factors that the it used for RP, the State determined that the NO_x RP emission limit for Rawhide Unit 101 is 0.145 lb/MMBtu (30-day rolling average). The State assumes that the RP emission limit can be achieved through the operation of ECC.

We agree with the State's conclusions, and we are proposing to approve its NO_x RP determination for PRPA Rawhide Unit 101.

PM RP Determination

Rawhide Unit 101 is equipped with fabric filter baghouses to control PM emissions with an emission limit of 0.03 lb/MMBtu. Stack tests show that the fabric filter baghouses are achieving a 99% reduction in PM. Fabric filter baghouses are the most stringent control technology for controlling PM emissions. The State also evaluated what would constitute the most stringent level of control for PM by looking at recent BACT determinations. Based on this evaluation, the State determined that an emission limit of 0.03 lb/MMBtu represents the most stringent level of control for this type of source. The State did not provide a full four-factor analysis plus visibility improvement modeling because the State determined RP to be the most stringent control technology and limit.

The State has determined that the PM RP emission limit for Rawhide Unit 101 is 0.03 lb/MMBtu (30-day rolling average). The State assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouses.

We agree with the State's conclusions, and we are proposing to approve its PM RP determination for PRPA Rawhide Unit 101.

ii. CENC Boiler 3

Background

The CENC facility includes five coal-fired boilers (Boilers 1-5) that supply steam and electrical power to Coors Brewery. Of these five Boilers, Boilers 4 and 5 are subject to BART and Boiler 3 is subject to RP. Boiler 3 is a 225 MMBtu/hr boiler. The State did not evaluate Boiler 1, Boiler 2, or fugitive dust sources at the facility for RP controls since emissions from these units were below the State's de minimis levels. The State's RP determination for CENC Boiler 3 can be found in Chapter 8.5.2.2 and Appendix D of the SIP.

SO_2 RP Determination

CENC Boiler 3 is currently uncontrolled for SO_2. The State determined that DSI and fuel switching to natural gas were technically feasible for reducing SO_2 emissions from Boiler 3. The State determined that dry FGD is not technically feasible for Boiler 3 due to space constraints onsite. Boiler 3's load range varies from low loads (ready to respond in the event of a malfunction in Boiler 4 or Boiler 5), medium loads (increased customer steam loads) to high loads (during Boiler 4 or Boiler 5 overhauls). The load range varies within the month and has patterns throughout the year. Because of the varying loads, the State has reasoned that a longer-than-three-year average of emissions is needed to determine baseline emissions. The State determined that a baseline average from 2000 – 2008 represents a reasonable depiction of actual emissions from this unit.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, nor are there any remaining-useful-life issues for this source. The baseline SO_2 emissions are 257 tpy. A summary of the State's SO_2 RP analysis is provided in Table 33 below. The emission rate for each control option in the table is reflective of the 30-day rolling average contained in the State's RP analysis.

Table 33 – Summary of CENC Boiler 3 SO_2 RP Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu) (30-Day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)
DSI	60	0.11	147	$1,340,661	$9,114
Fuel Switching	100	0.00	245	$1,428,911	$5,828

The State determined it would take CENC five years after SIP approval to install any controls.

The State used modeling results from CENC Boiler 4 to determine the projected visibility improvement for Boiler 3 because the units are similar and located at the same facility. CALPUFF modeling indicates a 0.08 dv improvement for DSI applied to Boiler 4. DSI controls for Boiler 4 would reduce SO_2 emissions by approximately 268 tons per year. DSI controls for Boiler 3 would reduce SO_2 emissions by about 147 tons per year. Fuel switching to natural gas would reduce SO_2 emissions by an estimated 245 tons annually. The State inferred that either control applied to Boiler 3 would yield visibility improvements of less than 0.10 dv.

The State determined that fuel switching and DSI were not reasonable to select as RP controls due to the high cost effectiveness values and low visibility improvement associated with these controls. Based on a fuel analysis, the State determined that the maximum SO_2 emissions rate from 2000-2010 is 0.99 lb/MMBtu. In establishing an RP emission limit, the State determined a 20% contingency factor is warranted for CENC Boiler 3 due to the different load factors discussed above. Based upon its consideration of the five factors that it used for RP, the

State has determined that the SO_2 RP emission limit for CENC Boiler 3 is 1.2 lbs/MMBtu (annual average).

We agree with the State's conclusions, and we are proposing to approve its SO_2 RP determination for CENC Boiler 3.

NO_x RP Determination

The State determined that flue gas recirculation (FGR), SNCR, ROFA, fuel switching to natural gas, and three options for SCR (regenerative SCR (RSCR), high temperature SCR (HTSCR), and low temperature SCR (LTSCR)) were technically feasible for reducing NO_x emissions at CENC Boiler 3. The State determined that LoTOx™, ECO, RRI, and coal reburn plus SNCR were not technically feasible. The State determined that because CENC Boiler 3 is a coal stoker boiler, LNBs are also not technically feasible.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, nor are there any remaining-useful-life issues for this source. A summary of the State's NO_x RP analysis is provided in Table 34 below. Baseline NO_x emissions are 205 tpy. The emission rate for each control option in the table is reflective of the 30-day rolling average contained in the State's RP analysis.

Table 34 – Summary of CENC Boiler 3 NO_x RP Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu) (30-Day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)
FGR	20	0.17	34	$1,042,941	$30,292
SNCR	30	0.15	51	$513,197	$10,146
Fuel Switching	35	0.14	84	$1,428,911	$16,950
ROFA w/Rotamix	57	0.09	77	$978,065	$9,496
RSCR	75	0.05	96	$978,065	$10,160
HTSCR	86	0.03	126	$1,965,929	$15,651
LTSCR	86	0.03	145	$2,772,286	$19,187

The State estimates that the source would need at least five years after SIP approval to install the control equipment.

The State used modeling results from CENC Boiler 4 to determine the projected visibility improvement for Boiler 3 since the units are similar and located at the same facility. CALPUFF modeling indicates a 0.12 dv improvement for LNB+SOFA+SNCR applied to Boiler 4. LNB+SOFA+SNCR controls for Boiler 4 would reduce NO_x emissions by approximately 368 tons per year. The highest performing SCR controls for Boiler 3 would reduce NO_x emissions by about 145 tons per year. Based on this information, the State has inferred that any control applied to Boiler 3 would yield visibility improvements of less than 0.12 dv. The State determined that none of the evaluated controls were reasonable because of the high cost effectiveness values and low visibility improvement for each of the controls.

Based on a review of historical load characteristics of this boiler, the State determined that RP for Boiler 3 is an annual NO_x limit based on 50% annual capacity utilization using the maximum capacity year in the last decade. Included in this annual capacity utilization, there is a 20% contingency factor for reasons explained above. The State determined that the NO_x RP emission limit for Boiler 3 is 246 tons/year (12-month rolling total).

We agree with the State's conclusions, and we are proposing to approve its NO_x RP determination for CENC Boiler 3.

PM RP Determination

CENC Boiler 3 is equipped with a fabric filter baghouse to control PM emissions with a current emission limit of 0.07 lb/MMBtu. Fabric filter baghouses are the most stringent control technology for controlling PM emissions, and stack tests show that the fabric filter baghouses are achieving a 98% reduction in PM. The State determined that PM RP for Boiler 3 is an emission limit of 0.07 lb/MMBtu. The State assumes the RP emission limit can be met with the operation of the current fabric filter baghouses.

While we do not agree with all of the State's assumptions and conclusions in arriving at a PM RP limit of 0.07 lb/MMBtu, we are proposing to approve the State's PM RP determination for CENC Boiler 3. Based on our review/analysis, it appears CENC is capable of achieving a lower emission limit than 0.07 lb/MMBtu with existing equipment. However, we anticipate that the visibility improvement that would result from lowering the limit to a value below 0.07 lb/MMBtu would be insignificant. Under these circumstances, we are proposing to find that the State's RP determination was reasonable.

We find that an emission limit of 0.07 lb/MMBtu is reasonable, as a lower emission limit would not result in significant visibility improvement. Thus, we are proposing to approve the State's PM RP determination for CENC Boiler 3.

iii. CSU – Nixon Unit 1

<u>Background</u>

The Nixon facility is located in Fountain, Colorado. This facility consists of one coal fired boiler (Unit 1), an auxiliary boiler, the associated equipment needed for generating electricity, and two natural-gas-fired simple cycle combustion turbines driving electricity generators. The facility also includes the various processes necessary to handle the coal, flyash and bottom ash. The State determined that Unit 1 and the two combustion turbines were subject to RP. The State determined the rest of the units at this facility had emissions below the de minimis thresholds set by the State. The boiler is a 227 MW unit with a pulverized-coal, dry-bottom, front-fired boiler that fires low sulfur western coal as the primary fuel. It can currently use No. 2 distillate oil or natural gas for an ignition fuel. The State's RP determination can be found in Chapter 8.5.2.3 and Appendix D of the SIP. The analysis for the combustion turbines can be found in section V.D.2.b.x of this notice.

SO_2 RP Determination

Nixon Unit 1 is currently uncontrolled for SO_2. The State determined that DSI and dry FGD were technically feasible for reducing SO_2 emissions from Nixon Unit 1. The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, nor are there any remaining-useful-life issues for this source. A summary of the State's SO_2 RP analysis is provided in Table 35 below. Baseline SO_2 emissions are 4,121 tpy based on the average of 2006-2008 actual emissions. The emission rate for each control option in the table is reflective of the 30-day rolling average contained in the State's RP analysis.

Table 35 – Summary of Nixon Unit 1 SO_2 RP Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu) (30-Day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98th Percentile Impact)
DSI – Trona	60	0.19	2,473	$9,438,692	$1,997	0.44
Dry FGD	78	0.11	3,215	$12,036,604	$3,744	0.46
Dry FGD	85	0.08	3,392	$13,399,590	$3,950	0.50

The State estimates it would take 3-5 years after SIP approval for the source to install controls on Nixon Unit 1.

The State determined that dry FGD was reasonable for RP control for Nixon Unit 1. Based upon its consideration of the five factors that it used for RP, the State determined that the SO_2 RP emission limit for CSU Nixon Unit 1 is 0.11 lb/MMBtu (30-day rolling average). The State assumes that the emission limit can be achieved with dry FGD. The State determined that a lower emissions limit (85% control efficiency) for Unit 1 was not reasonable as increased control costs to achieve such an emissions rate would not provide appreciable incremental improvements in visibility (0.04 delta dv).

We agree with the State's conclusions, and we are proposing to approve its SO_2 RP determination for CSU Nixon Unit 1.

NO_x RP determination

Nixon Unit 1 is currently controlled for NO_x emissions with LNBs. The State determined ULNB, OFA, SNCR, SNCR plus ULNB, and SCR were technically feasible for reducing NO_x emissions at Nixon Unit 1. The State determined ECO, RRI, and coal reburn plus SNCR were not technically feasible.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, nor are there any remaining-useful-life issues for this source. A summary of the State's NO_x RP analysis is provided in Table 36 below. Baseline NO_x emissions are 2,356 tpy based on the average of 2006-2008 actual emissions. The emission rate for each control option in the table is reflective of the 30-day rolling average contained in the State's RP analysis.

Table 36 – Summary of Nixon Unit 1 NO_x RP Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu) (30-Day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98th Percentile Impact)
ULNBs	20	0.24	471	$567,000	$1,203	0.15
OFA	25	0.22	589	$403,000	$684	0.15
ULNBs+OFA	30	0.21	707	$907,000	$1,372	0.16
SNCR	30	0.21	707	$3,266,877	$4,564	0.16
ULNBs +SCR	73	0.08	1,720	$11,007,000	$6,398	0.24
SCR	73	0.08	1,720	$11,010,000	$6,400	0.24

The State estimates it would take CSU 2-3 years to install SNCR and 3-4 years to install SCR after SIP approval.

The State determined NO_x RP is ULNBs plus OFA. The State eliminated SNCR, ULNBs plus SCR, and SCR from consideration due to the high cost effectiveness values and low visibility improvement for these controls. Based upon its consideration of the five factors that it used for RP, the State determined that the NO_x RP emission limit for Nixon Unit 1 is 0.21 lb/MMBtu (30-day rolling average). The State assumes that the emission limit can be achieved with ultra-low NO_x burners with overfire air control. The State did not choose SNCR as it would achieve the same emissions reductions at a greater expense.

We agree with the State's conclusions, and we are proposing to approve the State's NO_x RP determination for CSU Nixon Unit 1.

PM RP Determination

Nixon Unit 1 is equipped with fabric filter baghouses to control PM emissions with an emission limit of 0.03 lb/MMBtu. Stack tests show that the fabric filter baghouses are achieving greater than a 95% reduction in PM. The State determined that fabric filter baghouses are the most stringent control technology for controlling PM emissions. The State also evaluated what would constitute the most stringent level of control for PM by looking at recent BACT determinations. Based on this evaluation, the State determined that an emission limit of 0.03 lb/MMBtu represents the most stringent level of control for this type of source. The State did not provide a full four-factor analysis plus visibility improvement modeling because the State determined RP to be the most stringent control technology and limit.

The State has determined that the PM RP emission limit for CSU Nixon Unit 1 is 0.03 lb/MMBtu (30-day rolling average). The State assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouses.

We agree with the State's conclusions, and we are proposing to approve its PM RP determination for CSU Nixon Unit 1.

iv. Black Hills Energy Clark Power Plant, Units 1 and 2

Black Hills/Colorado Electric Utility Company informed the State that the Clark Units 1 and 2 will be shut down by December 31, 2013. The shutdown will result in SO_2, NO_x and PM reductions of approximately 1,457 tpy, 861 tpy, and 72 tpy, respectively. The State determined that the shutdown of Clark Power Plant Units 1 and 2 by December 31, 2013 is RP for this source. The State did not provide a RP analysis for this facility since the shutdown of the facility represents the most stringent control. The State's discussion for the source can be found in Chapter 8.5.2.4 of the SIP. The shutdown of Black Hills Energy Clark Power Plant Unit 1 and Unit 2 is required by the RH SIP (see section 8.5.2 of the SIP and Regulation No. 3, Part F, Section VI.B).

v. Holcim Florence Cement Plant

Background

The Holcim Florence Cement Plant is a Portland cement plant located in Florence, Colorado. In May 2002, a newly constructed cement kiln commenced operation at the plant. This more energy-efficient 5-stage preheater/precalciner kiln replaced three older wet process kilns. The Florence Plant includes a quarry where major raw materials used to produce Portland cement, such as limestone, translime and sandstone, are mined, crushed and then conveyed to the plant site. Emissions from the kiln system, raw mill, coal mill, alkali bypass and clinker cooler are all routed through a common main stack for discharge to the atmosphere. The kiln system is rated at 950 MMBtu per hour of fuel input with a nominal clinker production rate of 5,950 tons per day. It is permitted to burn the following fuel types: coal, tire derived fuel, petroleum coke, natural gas, dried cellulose, and oil, including non-hazardous used oil. The State determined that the kiln system, quarry, and finish mill were subject to RP and that all other units at this facility fall below the State's de minimis threshold. The quarry and finish mill only have PM emissions. The State RP determination for the Holcim Florence Cement Plant can be found in Chapter 8.5.2.5 and Appendix D of the SIP.

SO_2 RP Determination

The kiln system is currently controlled with a wet FGD with a current SO_2 permit limit of 1006.5 tpy. The wet FGD, in conjunction with good combustion practices and the inherent recycling and scrubbing of acid gases in the manufacturing process, achieves a 98.3% reduction in SO_2 emissions as measured by the total sulfur input into the system versus the amount of sulfur emitted to atmosphere. The State estimates that the wet FGD itself achieves an overall SO_2 removal efficiency of greater than 90%.

On August 9, 2010, EPA finalized changes to the NSPS for Portland Cement Plants. The NSPS requires new, modified, or reconstructed cement kilns to meet an emission standard of 0.4 pound of SO_2 per ton of clinker on a 30-day rolling average or a 90% reduction as measured at the inlet and outlet of the control device. While the new NSPS does not apply to the Holcim Portland Plant because it is an existing facility, the State determined that 90 percent control represents the most stringent level of control and wet FGD the most stringent control technology for Portland cement plants. Therefore, the State did not complete a full RP analysis.

The State did evaluate emissions limit tightening based on current operations. As a part of its submittals to the State, Holcim analyzed continuous hourly emission data for SO_2. The State used the hourly emission data from 2004 to 2008 to calculate the daily emission rates. The State calculated a 30-day rolling average emission rate by dividing the total emissions from the previous 30 operating days by the total clinker production from the previous 30 operating days. The State established two RP limits for the Holcim Florence Cement Plant. The State used the 99th percentile of the 30-day rolling average data to establish a short-term SO_2 RP emission limit of 1.30 pounds per ton of clinker (30-day rolling average). The State calculated the long-term annual limit by multiplying the long-term baseline SO_2 value of 0.77 lb/ton clinker (the mean of 0.51 pound per ton plus one standard deviation of 0.26 pound per ton) by the annual clinker limit of 1,873,898 tpy, and then dividing by 2,000 pounds per ton. The State determined that the SO_2 RP long-term limit is 721.4 tpy (12-month rolling total). The State assumes that the emission limits can be achieved through the operation of the existing wet FGD.

We agree with the State's conclusions, and we are proposing to approve its SO_2 RP determination for the Holcim Florence Cement Kiln.

<u>NO_x RP Determination</u>

NO_x emissions from the kiln are currently controlled by a number of technologies, including LNBs. The State determined water injection (the injection of water into the main flame of the kiln to act as a heat sink and reduce the flame temperature) and SNCR were technically feasible. The State determined that SCR is not commercially available for Portland cement kilns.

Although we disagree with the State's conclusion on the commercial availability of SCR for cement kilns, we accept the State's decision, for purposes of RH, not to analyze this control technology further. We note that EPA has acknowledged, in the context of establishing NSPS for Portland Cement Plants, substantial uncertainty regarding the cost effectiveness associated with the use of SCR at such plants. See 75 FR 54995. We expect the State to reevaluate this technology in subsequent RP planning periods.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, nor are there any remaining-useful-life issues for this source. A summary of the State's NO_x RP analysis is provided in Table 37 below. Baseline NO_x emissions are 1,931 tpy based on the average of 2007-2009 actual emissions. The emission rate in the table is reflective of the 30-day rolling average contained in the State's RP analysis. The State estimates that water injection would result in a 7 percent or less emission reduction and SCNR could achieve about 45 percent control.[22] Since the State's initial analysis indicated that SNCR would be reasonable for RP control, the State did not- analyze water injection further.

Table 37 – Summary of Holcim Florence Cement Kiln NO_x RP Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/ton of Clinker) (30-Day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98th Percentile Impact)
SNCR	45	2.73	1098.9	$2,520,000	$2,293	0.29

The State has determined that Holcim will need five years from SIP approval to install SNCR controls.

[22] An SNCR control efficiency of 50% is feasible for the Portland Plant kiln. However, to achieve the necessary system configuration and temperature profile, SNCR will be applied at the top of the preheater tower and thus the alkali bypass exhaust stream cannot be treated. To achieve the proper cement product specifications, the Portland Plant alkali bypass varies from 0 - 30% of main kiln gas flow. Adjusting by 10%, for the alkali bypass to account for the exhaust gas that is not treated (i.e., bypassed) by the SNCR system, the State determined the overall SNCR control efficiency for the main stack will be 45%.

The State determined that NO_x RP control is SNCR. The State has determined that the NO_x RP emission limits for the Holcim Florence Cement Kiln are 2.73 pounds per ton of clinker (30-day rolling average) and 2086.8 tpy (12-month rolling average). The State assumes that the emission limits can be achieved through the operation of the existing LNBs and the installation and operation of SNCR.

The State calculated the 30-day rolling average short-term limit by adjusting upward by 10% (to account for the use of tire-derived fuel) the short-term baseline emission rate of 4.47 pounds of NO_x per ton clinker, and by then accounting for SNCR at 45% control efficiency [4.47/0.9*(1-0.45) = 2.73]. The State calculated the long-term annual limit by adjusting the annual baseline emission rate of 3.64 lbs/ton clinker (the mean of 3.43 pounds per ton plus one standard deviation of 0.21 pound per ton) in a similar fashion [3.64/0.9*(1-0.45) = 2.23 lb/ton]. The State took the calculated value of 2.23 pounds per ton, multiplied it by the annual clinker limit of 1,873,898 tpy, and then divided by 2,000 pounds per ton to arrive at the 2,086.8 tpy NO_x limit.

We agree with the State's conclusions, and we are proposing to approve its NO_x RP determination for the Holcim Florence Cement Kiln.

PM RP Determination for the Kiln

The kiln system is currently controlled with fabric filter baghouses with an emission limit of 246.3 tpy. The units are exceeding a PM control efficiency of 95%. The State has determined that the existing fabric filter baghouses installed on the kiln system represent the most stringent control technology.

The 246.3 tpy limit equates to an annual average of 0.26 pound of PM per ton of clinker. The State evaluated the impact on visibility of a lower emission rate. The State modeled possible visibility improvements associated with two emission rates: an emission rate of 0.08 pound of PM per ton of clinker (19.83 lbs/hour) and a rate of 0.04 pound of PM per ton of clinker (9.92 lbs/hour). This analysis assumed the emissions were all attributable to the kiln (i.e., no contribution from the clinker cooler) to assess the impact of a possible reduction of the kiln emission limit. The 98th percentile impact for all pollutants is 0.435 dv. The modeling showed no change to this value when the State modeled the lower emission limits. The State's modeling demonstrates that PM is an insignificant contributor to visibility impairment.

Given the very limited impact of PM emissions from the kiln system on visibility impairment, the State determined that no additional PM emissions control is warranted. The State has determined that the PM RP emission limit for the Holcim Florence Cement Kiln is 246.3 tpy of PM (12-month rolling total) from the kiln system main stack (including emissions from the clinker cooler). The State assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouses.

We agree with the State's conclusions, and we are proposing to approve its PM RP determination for the Holcim Florence Cement Kiln.

<u>PM RP Determination for the Quarry[23]</u>

The quarry has a current PM emission limit of 47.9 tpy. The State has determined that the existing fugitive dust control plan and associated control measures represent the most stringent controls for the quarry emission sources. The control measures include: watering and the use of chemical stabilizers, compaction and re-vegetation of stockpiles, vehicle speed limitations, reclamation and sequential extraction of materials, paving, graveling and cleaning of haul roads, sequential blasting, wet drilling, and the suspension of activities during high wind

[23] The summary of the RP analysis was not included in the SIP. Please see the State's full RP analysis for information on the quarry and finish mill.

events. The State also determined that additional controls would result in no additional visibility benefit based on the low permitted emissions.

The State has determined that the PM RP emission limit for the Holcim Florence Cement Quarry is 47.9 tpy fugitive PM (12-month rolling total).

We agree with the State's conclusions, and we are proposing to approve its PM RP determination for the Holcim Florence Cement Quarry.

PM RP Determination for the Finish Mill

The finish mill is currently controlled with fabric filter baghouses with an emission limit of 34.3 tpy of PM (12-month rolling total). The units are exceeding a PM control efficiency of 95%. The State determined that the current control technology and limit represent the most stringent level of control for the finish mill. Accordingly, the State did not provide a four-factor analysis plus visibility improvement modeling for the finish mill.

The State has determined that the PM RP emission limit for the Holcim Florence Cement Finish Mill is 34.3 tpy (12-month rolling total). The State assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouses.

We agree with the State's conclusions, and we are proposing to approve its PM RP determination for the Holcim Florence Cement Finish Mill.

vi. Tri-State Generation Nucla Facility

Background

The Tri-State Nucla facility is located in Montrose County approximately 3 miles southeast of the town of Nucla, Colorado. The Nucla facility consists of one coal-fired steam-driven electric generating unit, Unit 4, with a rated electric generating capacity of 110 MW (gross). The Nucla facility is an atmospheric circulating fluidized bed (CFB) unit. Additionally, the facility includes a number of fugitive dust sources. Unit 4 is the only unit subject to RP as the fugitive dust sources fall below the de minimis levels set by the State. The State's RP determination for the Nucla facility can be found in Chapter 8.5.2.6 and Appendix D of the SIP.

SO_2 RP Determination

Unit 4 is currently controlled for SO_2 emissions by limestone injection achieving a 70% reduction in emissions. Unit 4 has a current permit limit of 0.4 lbs/MMBtu (30-day rolling average). The State determined that limestone injection improvements (LII), dry FGD, DSI, and LII with a dry FGD were technically feasible. Study-level information for hydrated ash reinjection (HAR) systems at Nucla or any other EGU in the western United States were not available for use in evaluating costs. Based on the lack of cost information, the State does not consider this option to be commercially available and did not consider HAR in this analysis. The State did not evaluate DSI, as this technology would achieve less than a 50% reduction in emissions, which is less than the current SO_2 controls.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, nor are there any remaining-useful-life issues for this source. A summary of the State's SO_2 RP analysis is provided in Table 38 below. Baseline SO_2 emissions are 1,335 tpy based on the average of 2006-2008 actual emissions. The emission rate for each control option in the table is reflective of the 30-day rolling average contained in the State's RP analysis. Costs for SO_2 control options (and NO_x) were evaluated based on analyses for similar systems proposed at other western CFB boiler units, specifically Spiritwood in North Dakota[24] and Bonanza in Utah.[25] The State did not model visibility improvement due to time constraints.

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[24] Barr, July 2007. "Application for a Permit to Construct a Combined Heat and Power (CHP) Plant." Prepared for Great River Energy – Spiritwood Station, Spiritwood, ND.

Table 38 – Summary of Nucla Unit 4 SO_2 RP Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu) (30-Day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)
LII	39.4	0.19	526	$914,290	$4,161
Dry FGD	87.0	0.04	1,162	$7,604,627	$6,547
LII + dry FGD	93.9	0.02	1,254	$9,793,222	$7,808

The State's analysis assumes that the LII will not require any construction or capital improvements and compliance time will be minimal. The State anticipates that the time necessary for installing dry FGD or dry FGD plus LII would be 3-5 years after SIP approval.

The State eliminated dry FGD and dry FGD plus limestone injection improvements from consideration due to the high cost effectiveness values. The State originally asserted in the Nucla RP analysis that limestone injection improvements are technically feasible. However, Tri-State provided additional information on November 29, 2011 in the Colorado Air Quality Control Commission hearing that introduced significant uncertainty regarding the technical feasibility of LII for Unit 4 at Nucla Station. The State determined upon further evaluation that LII beyond current operations were not feasible in all operating conditions.

Based upon its consideration of the four factors, the State has determined that the SO_2 RP emission limit for Nucla Unit 4 is 0.5 lb/MMBtu (30-day rolling average). The State assumes that the emission limit can be achieved through the operation of the current limestone injection system.

We agree with the State's conclusions, and we are proposing to approve the State's SO_2 RP determination for Nucla Unit 4.

[25] EPA, August 30, 2007. "Deseret Power Electric Cooperative, Bonanza Power Plant, Waste Coal Fired Unit: Prevention of Significant Deterioration Permit to Construct – Final Statement of Basis for Permit No. PSD-00-0002.01.00. "

NO$_x$ RP Determination

In 2006, Tri-State installed a small-scale SNCR system on Unit 4 that injects anhydrous ammonia to achieve NO$_x$ reductions. Tri-State does not operate the SNCR system frequently. It is used on occasions when NO$_x$ emissions approach 0.4 lb/MMBtu. Operation above this level at high unit capacity factors results in levels that approach the annual NO$_x$ limit of 1,987.9 tpy (12-month rolling average).

The State determined full-scale SNCR and SCR were technically feasible for reducing NO$_x$ emissions at Nucla Unit 4. Though the SIP states SCR is not technically feasible on a CFB coal-fired boiler, the State's RP analysis contains a discussion on SCR being technically feasible, and we agree with the State's assessment in the RP analysis. With respect to SNCR, the State has asserted that there is substantial uncertainty surrounding the potential control efficiency achievable by a full-scale SNCR system at a CFB boiler burning western coal. The State's estimates for control efficiency vary between 10 – 40% for NO$_x$ reduction potential.

The State determined that the costs for SCR would likely be excessive, and the State did not further evaluate this control option. The State estimated that the incremental cost of using SCR versus SNCR on a CFB Boiler as \$25,315 per ton per the Spiritwood BACT analysis and \$40,297 per ton per the Bonanza BACT analysis. The State expects a SCR system at the Nucla Station to have even higher costs due to the retrofit factor and small size of Unit 4.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of the remaining control evaluated, nor are there any remaining-useful-life issues for this source. A summary of the State's NO$_x$ RP analysis is provided in Table 39 below. Baseline NO$_x$ emissions are 1,760 tpy based on the average of 2006-2008 actual emissions. The emission rate for each control option in the table is reflective of the 30-

day rolling average contained in the State's RP analysis. The State did not model visibility improvement due to time constraints. The State evaluated SNCR at two different control efficiencies due to the uncertainty of SNCR control on this type of boiler.

Table 39 – Summary of Nucla Unit 4 NO_x RP Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu) (30-Day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)
SNCR	10.3	0.40	173	$2,238,592	$12,974
SNCR	43.6	0.25	730	$2,238,592	$3,065

The State anticipates that the time necessary to install and operate SNCR would be approximately 3-5 years after SIP approval.

Based on its consideration of the four factors, the State has determined that NO_x RP for Nucla Unit 4 is the following NO_x emission limit: 0.5 lb/MMBtu (30-day rolling average). Due to the uncertainty of the control efficiency of SNCR control, the State determined that it was not reasonable for NO_x RP control at this time.

We agree with the State's conclusions, and we are proposing to approve its NO_x RP determination for Tri-State Nucla Unit 4.

PM RP Determination

Nucla Unit 4 is equipped with fabric filter baghouses to control PM emissions with an emission limit of 0.03 lb/MMBtu. Stack tests show that the fabric filter baghouses are achieving a 99.9% reduction in PM. The State determined that fabric filter baghouses are the most stringent control technology for controlling PM emissions. The State also evaluated what would constitute the most stringent level of control for PM by looking at recent BACT determinations. Based on this evaluation, the State determined that an emission limit of 0.03 lb/MMBtu represents the most stringent level of control for this type of source. The State did not provide a full four-factor analysis because the State determined RP to be the most stringent control technology and limit.

The State has determined that the PM RP emission limit for Tri-State Nucla Unit 4 is 0.03 lb/MMBtu (30-day rolling average). The State assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouses.

We agree with the State's conclusions, and we are proposing to approve its PM RP determination for Tri-State Nucla Unit 4.

vii. Tri-State Craig Unit 3

Background

The Tri-State Craig Station is located in Moffat County about 2.5 miles southwest of the town of Craig, Colorado. This facility is a three unit coal-fired power plant with a total net electric generating capacity of 1264 MW. Craig Units 1 and 2 are subject to BART. The State determined Craig Unit 3 was subject to RP. Craig Unit 3 is a dry-bottom pulverized coal-fired boiler. The Craig facility also includes two cooling towers, coal handling systems, ash handling systems, limestone handling system, and the staging/landfill area. In addition to Craig Unit 3, the State determined that the ash handling system and the limestone hauling system were subject to RP (they only emit PM emissions, not SO_2 or NO_x). The State determined the other systems were not subject to RP as their emissions were below the de minimis threshold set by the State. The State's RP determination can be found in Chapter 8.5.2.7 and Appendix D of the SIP.

SO_2 RP Determination

Craig Unit 3 is currently controlled with a dry FGD currently achieving over 80 percent SO_2 reduction. The current emission limits are .20 lb/MMBtu (calendar day average), 80%

reduction (30-day rolling average). As mentioned earlier, if a BART source has current SO_2 controls achieving at least a 50% reduction in emissions, the state needs to evaluate upgrades to the existing control technology but does not need to consider the replacement of that technology (70 FR 39171). We conclude that it is reasonable to follow this approach for evaluating potential RP controls in this initial planning period. Colorado should consider replacement of existing scrubbers in future planning periods. The State considered the following dry FGD upgrades: 1) use of performance additives; 2) use of more reactive sorbent or increasing the pulverization level of sorbent; 3) engineering redesign of atomizer or slurry injection system. Based on the design of Unit 3, the State could not identify any performance additives that could be used and determined that Tri-State cannot use a more reactive sorbent or increase the pulverization level of sorbent. The source recently redesigned the slurry injection system, and the State could not identify any other feasible upgrades. Based on its analysis, the State determined that no upgrades are technically feasible. We agree with the State's assessment of possible upgrades. The State determined that fuel switching and DSI were technically feasible, but did not further analyze these controls as they would achieve less emission reductions than the current controls.

The State analyzed emission limit tightening based on current operations. Tri-State made upgrades to the dry FGD between 2007 and 2009. The maximum 30-day rolling emission rate post-upgrade (June 2009-June 2010) was 0.14 lbs/MMBtu and the average 30-day rolling average was 0.11 lbs/MMBtu. The State modeled the visibility improvement that would result from a 0.15 lbs/MMBtu emission limit and 0.07 lbs/MMBtu emission limit. The visibility improvement was 0.26 dv and 0.38 dv, respectively.

Based on its analysis, the State determined that a more stringent 30-day rolling SO_2 limit of 0.15 lbs/MMBtu represents an appropriate and reasonable level of emissions control for this dry FGD control technology. Upon review of 2009 emissions data from EPA's CAMD website, the State has determined that this emissions rate is achievable without additional capital investment. The State has determined that the SO_2 RP emission limit for Craig Unit 3 is 0.15 lb/MMBtu (30-day rolling average). The State assumes the emission limit is achievable with the current dry FGD controls.

The State has determined that a SO_2 limit lower than 0.15 lbs/MMBtu would not result in significant visibility improvement (0.12 dv), would likely result in frequent non-compliance events, and, would, thus, not be reasonable.

We agree with the State's conclusions, and we are proposing to approve its SO_2 RP determination for Tri-State Craig Unit 3.

NO_x RP Determination

Craig Unit 3 is currently controlled with LNBs and OFA that were installed in 2009. The State determined that combustion control refinements, neural network system (NNS) combustion controls, SNCR, and SCR were technically feasible. The State determined that ROFA, ECO, RRI, and coal reburn plus SNCR were not technically feasible.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, nor are there any remaining-useful-life issues for this source. A summary of the State's NO_x RP analysis is provided in Table 40 below. Baseline NO_x emissions are 6,402 tpy based on the average of 2006-2008 actual emissions. The emission rate for each control option in the table is reflective of the 30-day rolling average contained in the State's RP analysis. The State did not model combustion control refinements or NNS because of the extremely low control efficiency for these two control options.

Table 40 – Summary of Tri-State Craig Unit 3 NO_x RP Analysis

Control Technology	Control Efficiency (%)	Emission Rate (lb/MMBtu) (30-Day Rolling Average)	Emission Reduction (tpy)	Annualized Costs	Cost Effectiveness ($/ton)	Visibility Improvement (Delta dv for the Maximum 98th Percentile Impact)
Combustion Control Refinements	2	0.32	114	$122,000	$1,071	--
NNS	5	0.31	285	$280,000	$984	--
SNCR	15	0.28	858	$4,173,000	$4,887	0.32
SCR	75	0.08	4,281	$239,762,387	$6,952	0.79

The State eliminated SCR from consideration due to the high cost effectiveness value and the visibility improvement associated with this control. The State determined SNCR was reasonable for RP control. Based upon its consideration of the five factors that it used for RP, the State has determined that the NO_x RP emission limit for Craig Unit 3 is 0.28 lb/MMBtu (30-day rolling average). The State assumes that the RP emission limit can be achieved through the operation of SNCR.

We agree with the State's conclusions, and we are proposing to approve its NO_x RP determination for Tri-State Craig Unit 3.

PM RP Determination

Craig Unit 3 is equipped with fabric filter baghouses to control PM emissions with an emission limit of 0.013 lb/MMBtu for PM filterable and 0.012 lb/MMBtu for PM_{10}. Stack tests show that the fabric filter baghouses are achieving over a 95% reduction in PM. The State determined that fabric filter baghouses are the most stringent control technology for controlling PM emissions. The State also evaluated what would constitute the most stringent level of control for PM by looking at recent BACT determinations. Based on this evaluation, the State determined that the current emission limits represents the most stringent level of control for this type of source. The State did not provide a full four-factor analysis plus visibility improvement modeling because the State determined RP to be the most stringent control technology and limit.

The State has determined that the PM RP emission limits for Tri-State Craig Unit 3 are 0.013 lb/MMBtu for filterable PM (30-day rolling average) and 0.012 lb/MMBtu for PM_{10} (30-day rolling average). The State assumes that the emission limits can be achieved through the operation of the existing fabric filter baghouses.

We agree with the State's conclusions, and we are proposing to approve its PM RP determination for Tri-State Craig Unit 3.

viii. PSCO Cameo Station

PSCO informed the State that the Cameo Station east of Grand Junction, Colorado would be shut down by December 31, 2011, resulting in SO_2, NO_x, and PM reductions of approximately 2,618, 1,140, and 225 tons per year, respectively. The State did not perform a RP analysis for this source since a shutdown is the most stringent control. The State determined that the shutdown of Cameo Station by December 31, 2011 is RP for this source. We agree with the State's conclusions, and we are proposing to approve its RP determination for PSCO Cameo Station. The State's discussion of RP for Cameo Station can be found in Chapter 8.5.2.8 of the SIP. The shutdown of PSCO Cameo Station is required by the RH SIP (see Chapter 8.5.2 of the SIP and Regulation No. 3, Part F, Section VI.B).[26]

Summary of State's RP Determinations

Table 41 - Summary of the State's RP Determinations for Stationary Sources

Emission Unit	Assumed NO_x	NO_x Emission	Assumed SO_2	SO_2 Emission	Assumed

[26] PSCO Cameo Station was shut down in December 2010.

	Control Type	Limit	Control Type	Limit	Particulate Control and Emission Limit
Rawhide Unit 101	Enhanced Combustion Control*	0.145 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
CENC Unit 3	No Control	246 tons per year (12-month rolling total)	No Control	1.2 lbs/MMBtu	Fabric Filter Baghouse* 0.07 lb/MMBtu
Nixon Unit 1	ULNBS with OFA	0.21 lb/MMBtu (30-day rolling average)	Lime Spray Dryer	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Clark Units 1 &2	Shutdown by 12/31/2013	0	Shutdown by 12/31/2013	0	Shutdown by 12/31/2013
Holcim - Florence Kiln	SNCR	2.73 lbs/ton clinker (30-day rolling average) 2,086.8 tons/year	Wet Lime Scrubber*	1.30 lbs/ton clinker (30-day rolling average) 721.4 tons/year	Fabric Filter Baghouse* 246.3 tons/year
Nucla	No Control	0.5 lb/MMBtu (30-day rolling average)	Limestone Injection*	0.4 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 3	SNCR	0.28 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.15 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.013 lb/MMBtu filterable PM 0.012 lb/MMBtu PM10
Cameo	Shutdown by 12/31/2011	0	Shutdown by 12/31/2011	0	Shutdown by 12/31/2011

* Controls already operating

ix. Area Oil and Gas Sources

Because the area source oil and gas category is made up of numerous smaller sources, the State determined it is only practical to evaluate the category for RP control as a whole. When reviewing oil and gas area sources, the State identified heater-treaters and RICE as the largest NO_x emission sources.

a. Oil and Gas Heater-Treaters

A heater-treater is a device used to remove contaminants from the natural gas or oil at or near the wellhead before the gas is sent down the production line to a natural gas processing plant or the oil is collected in storage tanks. The latest 2018 emissions inventory for the State assumes approximately 23,000 tons of NO_x per year from 26,000 natural gas and oil heater-treaters. This equates to approximately 0.88 tpy of NO_x per gas/oil well heater-treater.

The State's research shows that emission controls and control applications for this source category are not well developed and have focused primarily on methane reductions. Though the State identified some technically feasible control options, the State determined that the costs of compliance and the control effectiveness could not be confidently determined. Because of the uncertainty of controls, the State has determined that additional controls under RP are not reasonable in this initial planning period.

b. RICE

Background

Power generated by large RICE is generally used to compress natural gas or to generate electricity in remote locations. The designation large RICE refers to engines have a rating of at least 100 horsepower (hp) for the purpose of this RP analysis. Large RICE produce power by combustion of fuel and are operated at various air-to-fuel ratios. RICE are operated with either fuel-rich ratios, which are called rich-burn (RB) engines, or air-rich ratios, which are called lean-burn (LB) engines. The State's 2018 emission inventory shows that large RICE represent 16% of the Statewide point source NO_x emission inventory, with 2018 emissions expected to be 16,199 tpy.

The State determined the following were technically feasible for controlling NO_x emissions from RICE: 1) air/fuel ratio adjustment for LB engines; 2) ignition/spark timing retard for LB engines; 3) 3-way non-selective catalytic reduction (NSCR) for RB engines; 4) SNCR for RB and LB engines; 5) SCR for LB engines; and 6) replace RICE with electric motors for LB and RB engines.

A summary of the State's RP analysis for RICE engines is provided in Table 42 below. Because control effectiveness and cost effectiveness is dependent on a number of engine-specific factors, the State has provided a range for these factors. Due to a lack of available information, the State did not provide the cost effectiveness for SNCR.

Table 42 – Summary of RICE Controls for RP

Control Technology	Control Effectiveness (%)	Cost Effectiveness ($/ton)
Lean Burn (Air/Fuel Ratio Adjustment)	5-30%	$320-$8,300
Lean Burn (Ignition/Spark Timing Retard)	20%	$310-$2,000
Rich Burn NSCR w/an air to fuel ratio (ATF) controller	80-90%	$571
Rich/Lean Burn SNCR	50-95%	--
Lean Burn SCR	80-90%	$430 - $4,900
Replace RICE with electric motors	60-100%	$4,700 or more

For RICE NO_x control under the RHR, the State determined that the installation of NSCR plus ATF controllers on all RB RICE greater than 500 hp throughout the State satisfies RP requirements. Additional NO_x control for lean burn RICE throughout the State is not reasonable for this planning period. For existing RICE less than 500 hp, the State determined that no additional control is necessary for RP in this planning period. Colorado's emission inventory indicates that in the 2007-2008 timeframe, there were 538 engines with less than 500 hp in the State, and these engines emitted 5,464 tpy of NO_x. At an average of about 10 tons of NO_x emissions per year, the State determined controlling engines of this size is not reasonable.

In addition, for new and modified RICE of 100 hp or greater, the State is relying on emissions controls that are required by EPA's NSPS subpart JJJJ, 40 CFR part 60, and EPA's NESHAP subpart ZZZZ, 40 CFR part 63. The State determined that these federal control requirements satisfy RP for these sources in this planning period.

Colorado adopted regulations to control NO_x emissions from RICE in 2004. For the Denver metro area/North Front Range ozone control area, the State revised Regulation No. 7 to require the installation of controls on new and existing rich burn RICE larger than 500 hp by May 1, 2005. EPA approved the revisions to Regulation No. 7 as part of the Colorado SIP on August 19, 2005 (70 FR 48652).

In December 2008, Colorado adopted section XVII.E.3.a into Regulation No. 7. Section XVII.E.3.a applies to all existing RB RICE over 500 hp throughout the State. The revisions to Regulation No. 7 required that by July 1, 2010 all existing RB RICE over 500 hp in Colorado had to install NSCR with an ATF controller. Sources subject to emission controls under a MACT, BACT, or NSPS are not subject to the requirements of section XVII.E.3.a. In addition, sources that fall below State permitting thresholds are not subject to the requirements of section XVII.E.3.a. An exemption from control for RB RICE can be obtained upon demonstration that the cost of emission control would exceed $5,000 per ton. The State has included Regulation No. 7, section XVII.E.3.a, as part of the RH SIP to become federally enforceable upon EPA approval.

We are proposing to approve the State's RP determination for RICE engines. We are also proposing to approve Regulation No. 7, section XVII.E.3.a, as part of the SIP.

x. Combustion Turbines

Combustion turbines fueled by natural gas are either co-located with coal-fired electric generating units or are stand-alone facilities. These units are primarily used to supplement power supply during peak demand periods when electricity use is highest. Typical emissions for this source type may be significant for NO_x, but usually have very low SO_2 and PM_{10} emissions.

The State evaluated combustion turbines that are co-located at subject-to-BART or subject-to-RP sources. The State determined there are five BART and RP facilities with combustion turbines: PSCO Valmont Generating Station, PSCO Arapahoe Generating Station, CSU - Nixon Power Plant, PRPA Rawhide Energy Station, and PSCO Pawnee Generating Station. Of these, only two turbines located at the Nixon Front Range Power Plant (Turbine #1 and Turbine #2) emit levels of pollutants above the State de minimis levels for NO_x. Baseline NO_x emissions based on the average of 2006-2008 actual emissions are 159.6 tpy for Turbine #1 and 148 tpy for Turbine #2.

The combustion turbines at the Nixon Front Range Power Plant were installed with advanced dry-low-NO_x combustion systems, which are achieving a control efficiency of 89.4% on Turbine #1 and 90.1% on Turbine #2. The State determined that the following were technically feasible controls for NO_x: 1) dry controls using advanced combustor design to suppress NO_x formation and/or promote CO burnout (already installed); and 2) post-combustion controls (SNCR, SCR). Although post-combustions controls are technically feasible, the State's search of the EPA's RACT/BACT/LAER Clearinghouse database revealed SCR is the predominant post-combustion control technology for combustion turbines and did not find any examples of SNCR post-combustion technology applied to combustion turbines. The State could not find any instances of commercial scale SNCR applied at combustion turbines, so the State eliminated SNCR.

The State analyzed SCR for RP control. The State determined that applying SCR at a 90% control efficiency to both turbines would result in about 275 tons of NO_x reduced annually with a capital expenditure of at least $15 million. The State estimated that SCR for these turbines would range from approximately $57,000 - $62,000 per ton of NO_x reduced annually. Based on the cost effectiveness value, the State determined that SCR was not reasonable for RP control. Combustion turbines are subject to 40 CFR part 60, subpart GG – Standards of Performance for Stationary Gas Turbines, which limits nitrogen oxides to 117.8 percent by volume at 15 percent oxygen on a dry basis (60.332(a)(1)), supported by monitoring and testing. The State determined that the limits of 40 CFR part 60, subpart GG are NO_x RP for combustion turbines.

We agree with the State's analysis and are proposing to approve its RP determination for combustion turbines and for the CSU - Nixon Power Plant Turbine #1 and Turbine #2.

3. **Reasonable Progress Goals**

40 CFR 51.308(d)(1) requires states to "establish goals (in dvs) that provide for RP towards achieving natural visibility conditions" for each Class I area of the State. These RP goals are interim goals that must provide for incremental visibility improvement for the most impaired visibility days, and ensure no degradation for the least impaired visibility days. The RP goals for the first planning period are goals for the year 2018. The State's discussion of RP and RPGs can be found in Chapter 8 and section 9.5 of the SIP.

Colorado is relying on the WRAP's CMAQ regional modeling performed in 2009 to establish its RP goals for 2018. As part of the 2009 CMAQ modeling, WRAP included all western states' reasonably foreseeable control measures in the projections of 2018 visibility levels.

The Regional Modeling Center at the University of California Riverside, under the oversight of the WRAP Modeling Forum, performed modeling used for the RH long-term strategy for the WRAP member states, including Colorado. The modeling analysis is a complex technical evaluation that began with selection of the modeling system. The Regional Modeling

Center primarily used the CMAQ photochemical grid model to estimate 2018 visibility conditions in Colorado and all western Class I areas, based on application of the RH strategies in the various state plans, including assumed controls on BART sources.

The Regional Modeling Center developed air quality modeling inputs, including annual meteorology and emissions inventories for: 1) a 2002 actual emissions base case; 2) a planning case to represent the 2000–2004 RH baseline period using averages for key emissions categories; and 3) a 2018 base case of projected emissions determined using factors known at the end of 2005. Each of these inventories underwent a number of revisions throughout the development process to arrive at the final versions used in CMAQ modeling. The WRAP states' modeling was developed in accordance with our guidance.[27] A more detailed description of the CMAQ modeling performed for the WRAP can be found in the Colorado Class I area TSDs.

The photochemical modeling of RH for the WRAP states for 2002 and 2018 was conducted on the 36-km resolution national regional planning organization domain that covered the continental United States, portions of Canada and Mexico, and portions of the Atlantic and Pacific Oceans along the east and west coasts. The Regional Modeling Center examined the model performance of the regional modeling for the areas of interest before determining whether the CMAQ model results were suitable for use in the RH assessment of the long-term strategy and for use in the modeling assessment. The 2002 modeling efforts were used to evaluate air quality/visibility modeling for a historical episode, in this case, for calendar year 2002, to demonstrate the suitability of the modeling systems for subsequent planning, sensitivity, and

[27] Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze, (EPA–454/B–07–002), April 2007, located at http://www.epa.gov/scram001/guidance/guide/final-03-pm-rh-guidance.pdf. Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations, August 2005, updated November 2005 (''our Modeling Guidance''), located at *http://www.epa.gov/ttnchie1/eidocs/eiguid/index.html*, EPA–454/R–05–001.

emissions control strategy modeling. Model performance evaluation compares output from model simulations with ambient air quality data for the same time period to determine whether model performance is sufficiently accurate to justify using the model to simulate future conditions.

Once the Regional Modeling Center determined that model performance was acceptable, it used the model to determine the 2018 RP goals using the current and future year air quality modeling predictions, and compared the RP goals to the uniform rate of progress.

The State determined that the WRAP 2018 projections represent significant visibility improvement and RP toward natural visibility based upon the State's consideration of the factors required for BART and RP.   The State is adopting the WRAPs 2018 projections as its RPG for each Class I area in Colorado. Table 43 shows the URP and the 2018 RPG adopted by the State for such areas.

Table 43 – Colorado's URP and RP Goal for 2018

	20% Worst Days				20% Best Days	
Colorado Class I Areas	2000-2004 Baseline (dv)	2018 URP (dv)	Reduction Needed to Reach URP Goal (delta dv)	2018 CMAQ Modeling Projection – State's RP Goal	2000-2004 Baseline (dv)	2018 CMAQ Modeling Projection
Great Sand Dunes National Park and Preserve	12.78	11.35	1.43	12.20	4.5	4.16
Mesa Verde National Park	13.03	11.58	1.45	12.5	4.32	4.10
Mount Zirkel & Rawah Wilderness Area	10.52	9.48	1.04	9.91	1.61	1.29
Rocky Mountain National Park	13.83	12.27	1.56	12.83	2.29	2.06
Weminuche Wilderness, Black Canyon of Gunnison, and La Garita Wilderness	10.33	9.37	0.96	9.83	3.11	2.93

Eagles Nest Wilderness, Flat Tops Wilderness, Maroon Bells-Snowmass Wilderness, and West Elk Wilderness	9.61	8.78	0.83	8.98	0.70	0.53

Table 43 shows that the State's RH SIP will provide for improvement in visibility for the most-impaired days over the period ending in 2018 and will allow for no degradation in visibility for the least-impaired days.

Table 43 also shows that Colorado is not meeting the URP to meet natural visibility conditions by 2064 because the projected 2018 RPG is greater than the 2018 URP. The State finds that the RPGs established in this SIP are reasonable for this planning period and that achieving the URP in this planning period is not reasonable. Pursuant to 40 CFR 51.308(d)(1)(ii), the State has determined and presented detailed analyses to show why certain controls for specified RP sources are reasonable, and why additional controls during this planning period are not reasonable based upon its consideration of the required factors for RP (40 CFR 51.308(d)(1)(i)(A)). The State has determined and presented detailed analyses to show why certain controls for specified BART sources are reasonable based upon its consideration of the five-factors (40 CFR 51.308(e)(1)(A)). In addition, sources outside of the modeling domain are the single largest contributor to sulfate or nitrate at many Class I areas (see Table 29 in section V.D.1 of this notice). These sources are not under the control of Colorado or the surrounding States, and will not be significantly controlled by 2018. As discussed below, the State consulted with other states on RP.

Since the State is not meeting the URP, the State is required by 40 CFR 51.308(d)(1)(ii) to assess the number of years it would take to reach natural conditions if visibility improvement continues at the current rate of progress. The State has calculated the year and the length of time to reach natural visibility as follows: Great Sand Dunes: 2152 (148 years); Mesa Verde: 2168 (164 years); Zirkel and Rawah: 2106 (102 years); Rocky Mountain: 2098 (94 years); Black Canyon, Weminuche, and La Garita: 2119 (115 years); and Eagles Nest, Flat Tops, Maroon Bells and West Elk: 2083 (79 years).

We note that the WRAP 2018 reasonable progress projections did not reflect the additional RH controls that Colorado adopted in 2010. These controls included additional BART requirements, the PSCO BART alternative, and RP limits as described above. These additional controls will produce about 44,500 tpy of NO_x and SO_2 reductions that were not included in the WRAP CMAQ modeling. Thus, it is likely that the State is closer to the URP than is indicated by the WRAP modeling.

EPA has evaluated Colorado's demonstrations concerning the RPGs and finds that they provide for reasonable progress towards natural visibility conditions for the first planning period. Based on the RP factors, Colorado has demonstrated that it is not reasonable to attain the URPs for Colorado's Class I areas in the first planning period, and that Colorado's RPGs (as augmented by the additional measures that Colorado adopted in 2010) are reasonable. Colorado has adopted BART, BART alternative, and RP controls that will achieve substantial reductions of NO_x and SO_2 emissions by 2018. We find that Colorado, considering the statutory BART and RP factors, has reasonably evaluated and rejected more stringent controls in this first planning period. We also find that Colorado has focused on an appropriate set of sources and source categories in considering potential reasonable progress controls in this first planning period. Finally, we agree that sources outside of the modeling domain are the single largest contributor to sulfate or nitrate at many Class I areas, that these sources are not under the control of Colorado or the surrounding states, and that they will not be significantly controlled by 2018.

This is another major reason that it is not reasonable for the Class I areas in Colorado to attain the URPs in 2018. For these reasons, EPA is proposing that the State's RPGs are reasonable.

E. Long Term Strategy

1. Emission Inventories

40 CFR 51.308(d)(3)(iii) requires that Colorado document the technical basis, including modeling, monitoring, and emissions information, on which it relied to determine its apportionment of emission reduction obligations necessary for achieving RP in each mandatory Class I Federal area it affects. Colorado must identify the baseline emissions inventory on which its strategies are based. 40 CFR 51.308(d)(3)(iv) requires that Colorado identify all anthropogenic (human-caused) sources of visibility impairment it considered in developing its long-term strategy. This includes major and minor stationary sources, mobile sources, and area sources.

In order to meet these requirements, Colorado relied on the emission inventory developed by the WRAP. The pollutants inventoried by the WRAP that Colorado used for this SIP include SO_2, NO_x, VOC, OC, EC, $PM_{2.5}$, PM_{10}, and ammonia. WRAP developed an inventory for the baseline year 2002 and provided projections of future emissions in 2018 based on expected controls, growth, or other factors. The emission inventories developed by the WRAP were calculated using best available data and approved EPA methods. [28]

There are a number of emission inventory source categories identified in the Colorado SIP: point, area, on-road mobile, off-road mobile, anthropogenic fire, natural fire, road dust, fugitive dust, area source oil and gas, and biogenic emissions. The State provided the 2002

[28] The methods WRAP used to develop these emission inventories are described in more detail in *Technical Support Document for Technical Products Prepared by the Western Regional Air Partnership (WRAP) in Support of Western Regional Haze Plans*; February 28, 2011. This document is included in the Supporting and Related Materials section of the docket.

baseline, the 2018 projected emissions, and the net change of emissions between 2002 and 2018 for SO_2, NO_x, VOC, OC, EC, $PM_{2.5}$, PM_{10}, and ammonia for each of the above source categories. Following is a summary of the emission inventory for each pollutant by source.

SO_2

Sulfur dioxide emissions come primarily from coal combustion at EGUs but smaller amounts come from natural gas combustion, mobile sources and wood combustion.

Table 44 – Colorado SO_2 Emissions – 2002 and 2018

Source Category	Baseline 2002	Future 2018	Percent Change
Point	97,984	44,062	-55
Area	6,533	7,644	17
On-Road Mobile	4,389	677	-85
Off-Road Mobile	3,015	754	-75
WRAP Area O & G	118	11	-91
Road Dust	4	6	34
Fugitive Dust	6	5	-13
Anthropogenic Fire	108	91	-15
Natural Fire	3,335	3,335	0
Biogenic	--	--	--
Total	115,492	56,585	-51

Overall, SO_2 emission source categories are expected to decline statewide by 51% by 2018. Area sources is the only source category expected to increase by 2018 (we are discounting the 2 tpy increase in road-dust). Increases in area source emissions are linked to population growth.

NO_x

NO_x emissions in Colorado come mostly from point sources and from on-road and off-road mobile sources.

Table 45 – Colorado NO_x Emissions – 2002 and 2018

Source Category	Baseline 2002	Future 2018	Percent Change

Point	118,667	101,818	-14
Area	11,729	16,360	39
On-Road Mobile	141,883	45,249	-68
Off-Road Mobile	62,448	37,916	-39
WRAP Area O & G	23,518	33,517	43
Road Dust	1	1	0
Fugitive Dust	16	14	-13
Anthropogenic Fire	520	408	-21
Natural Fire	9,377	9,377	0
Biogenic	37,349	37,349	0
Total	405,507	282,010	-30

Overall, NO_x emissions in Colorado are expected to decline by 30% by 2018. Area source and oil and gas emissions are the only source categories expected to increase. Area source emissions increases are related to population growth, and increases in oil and gas emissions are attributable to increased oil and gas development.

VOCs

VOCs come from such sources as automobiles, industrial and commercial facilities, solvent use, and refueling automobiles. Substantial natural emissions of VOCs come from vegetation.

Table 46 – Colorado VOC Emissions – 2002 and 2018

Source Category	Baseline 2002	Future 2018	Percent Change
Point	91,750	77,312	-16
Area	99,191	136,032	37
On-Road Mobile	100,860	41,489	-59
Off-Road Mobile	38,401	24,684	-36
WRAP Area O & G	27,259	43,639	60
Road Dust	--	--	--
Fugitive Dust	--	--	--
Anthropogenic Fire	915	666	-27
Natural Fire	20,404	20,404	0
Biogenic	804,777	804,777	0
Total	1,183,557	1,149,002	-3

Overall, VOC emissions are projected to decrease by 3% statewide, with a 37% increase in area source emissions and a 60% increase in oil and gas emissions. Area source emission increases are a result of increased population growth, and increases in oil and gas emissions are attributable to increased oil and gas development.

OC

OC are emitted directly from the combustion of organic material. A wide variety of sources contribute emissions to this pollutant, including diesel emissions and combustion byproducts from wood and agricultural burning.

Table 47 – Colorado OC Emissions – 2002 and 2018

Source Category	Baseline 2002	Future 2018	Percent Change
Point	17	3	-83
Area	8,432	8,738	4
On-Road Mobile	1,280	1,288	1
Off-Road Mobile	1,286	843	-34
WRAP Area O & G	--	--	--
Road Dust	102	135	33
Fugitive Dust	777	677	-13
Anthropogenic Fire	850	621	-27
Natural Fire	30,581	30,581	0
Biogenic	--	--	--
Total	43,325	42,886	-1

Overall, OC emissions decrease by 1% in 2018. The main source category expected to increase by 2018 is road dust. The increase in road dust is associated with increases in population and more vehicle miles traveled.

EC

Elemental carbon, also known as soot, is a byproduct of incomplete combustion. Emissions and reductions in this category are dominated by mobile sources. Expected new federal emission standards for mobile sources, especially for diesel engines, along with fleet replacement, are the reason for the reductions.

Table 48 – Colorado EC Emissions – 2002 and 2018

Source Category	Baseline 2002	Future 2018	Percent Change
Point	--	--	--
Area	1,264	1,325	5
On-Road Mobile	1,448	408	-72
Off-Road Mobile	3,175	1,344	-58
WRAP Area O & G	--	--	--
Road Dust	9	11	33
Fugitive Dust	53	46	-13
Anthropogenic Fire	92	74	-20
Natural Fire	6,337	6,337	0
Biogenic	--	--	--
Total	12,377	9,545	-23

Overall, this category is expected to decline by 23%, with on-road and off-road mobile sources expected to decline by 72% and 58%, respectively. The main source category expected to increase by 2018 is road dust. The increase in road dust is associated with increases in population and more vehicle miles traveled.

$PM_{2.5}$

Fine soil emissions are largely related to agricultural and mining activities, windblown dust from construction areas and emissions from unpaved and paved roads.

Table 49 – Colorado $PM_{2.5}$ Emissions – 2002 and 2018

Source Category	Baseline 2002	Future 2018	Percent Change
Point	6	85	1404
Area	4,170	4,311	3
On-Road Mobile	--	--	--
Off-Road Mobile	--	--	--
WRAP Area O & G	--	--	--
Road Dust	1,082	1,435	33
Fugitive Dust	13,401	11,679	-13
Windblown Dust	15,105	15,105	0
Anthropogenic Fire	253	169	-33

Natural Fire	1,948	1,948	0
Biogenic	--	--	--
Total	35,964	34,732	-3

Overall, $PM_{2.5}$ emissions are expected to decrease 3%. Increases in road dust emissions are tied to population growth and vehicle miles traveled.

PM_{10}

PM_{10} is closely related to the same sources as fine soil emissions, but other activities like rock crushing and processing, material transfer, open pit mining, and unpaved road emissions can be prominent sources.

Table 50 – Colorado PM_{10} Emissions – 2002 and 2018

Source Category	Baseline 2002	Future 2018	Percent Change
Point	21,096	26,828	27
Area	1,363	1,388	2
On-Road Mobile	794	917	15
Off-Road Mobile	--	--	--
WRAP Area O & G	--	--	--
Road Dust	8,930	11,826	32
Fugitive Dust	67,642	67,910	0
Windblown Dust	135,945	135,945	0
Anthropogenic Fire	51	32	-37
Natural Fire	5,973	5,973	0
Biogenic	--	--	--
Total	241,794	250,818	4

Overall, PM_{10} emissions are expected to increase by 4% in 2018. Increases in coarse mass are seen in the fugitive dust category. The increase in PM_{10} from road dust is associated with population growth and increased vehicle miles traveled. Point source emissions are addressed by the State for BART and RP sources.

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

40 CFR 51.308(d)(3)(i) requires that Colorado consult with another state if its emissions are reasonably anticipated to contribute to visibility impairment at that state's Class I area(s), and that Colorado consult with other states if those other states' emissions are reasonably anticipated to contribute to visibility impairment at its Class I areas. Colorado consulted with other states during ongoing participation in the WRAP while developing its SIP. Through the WRAP consultation process, Colorado has reviewed and analyzed contributions from other states that reasonably may cause or contribute to visibility impairment in Colorado's Class I areas and Colorado's impact on other states' Class I areas. The State held specific discussions with states that have a primary impact on Colorado Class I areas. These include California, Utah, Nebraska, Wyoming, New Mexico, and Arizona.

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

Colorado analyzed the WRAP PSAT modeling and determined that emissions from the State do not significantly impact other states' Class I areas. Colorado's largest visibility impacts are at Canyonlands National Park in Utah and Bandelier National Monument in New Mexico. Colorado's total nitrate and sulfate contributions represent 1.0% and 0.5%, respectively, of total haze at these Class I areas. The State determined this is not a meaningful level of contribution.

Colorado accepted and incorporated the WRAP-developed visibility modeling into its RH SIP, and the State's RH SIP includes the controls assumed in the modeling. Colorado satisfied the RHR's requirements for consultation and included controls in the SIP sufficient to address the relevant requirements of the RHR related to impacts on Class I areas in other states.

We are proposing to find that the State has met the requirements for consultation under 40 CFR 51.308(d)(3)(ii) and 40 CFR 51.308(d)(3)(iii).

3. Mandatory Long-Term Strategy Requirements

40 CFR 51.308(d)(3)(v) requires that Colorado, at a minimum, consider certain factors in developing its long-term strategy (the long-term strategy factors). These are: a) emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment (RAVI); b) measures to mitigate the impacts of construction activities; c) emissions limitations and schedules for compliance to achieve the RPGs; d) source retirement and replacement schedules; e) smoke management techniques for agricultural and forestry management purposes including plans that currently exist within the state for these purposes; f) enforceability of emissions limitations and control measures; and g) the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.

a. Reductions Due to Ongoing Air Pollution Programs

In addition to its BART and RP determinations, the State's long-term strategy contains other reductions due to ongoing air pollution programs. The State's long-term strategy contains both state only and federally enforceable programs. Some examples of these programs that are federally enforceable and the emission reductions they achieve include: 1) oil and gas condensate tank control regulations for the Front Range region that have achieved approximately 52,000 tpy of VOC emission reductions by 2007 with additional projected reductions of 18,000 tpy by 2010 (Regulation No. 7); 2) existing industrial engine control regulations for the Front Range region that have achieved NO_x and VOC emissions reductions of approximately 8,900 tpy (Regulation No. 7); 3) PM_{10} emission reduction programs in PM_{10} maintenance areas throughout the State; and 4) fugitive dust control programs for construction, mining, vehicular traffic, and industrial sources state-wide (Regulation No. 1). The State has also adopted some of the federal NSPS and the New Source Review and PSD permit requirements for stationary sources. Additional information on ongoing air pollution programs is included in Chapter 9 of the State SIP.

b. Measures to Mitigate the Impacts of Construction Activities

Regulation No.1 *Particles, Smokes, Carbon Monoxide, and Sulfur Oxides* and Regulation No. 3 *Air Pollution Emission Notices-Permits* have requirements that pertain to controlling emissions from construction activity. EPA has approved both regulations into the Colorado SIP. Regulation No. 3 requires air pollution sources to file Air Pollutant Emission Notices with the State. It also requires that new or modified sources of air pollution, with certain exemptions, obtain preconstruction permits. Regulation No. 1 sets forth emission limitations, equipment requirements and work practices (abatement and control measures) intended to control the emissions of particles, smoke and sulfur oxides from new and existing stationary sources, including construction activities.

c.Smoke Management

Colorado addresses the requirements for smoke management in Regulation No. 9 *Open Burning, Prescribed Fire, and Permitting*. The intent of Regulation No. 9 is to prevent unacceptable smoke impacts, pertaining to both health and visibility. The rule applies to all open burning activity within Colorado, with the exception of agriculture open burning.[29] Section III.A of the regulation requires anyone seeking to conduct open burning to obtain a permit from the State before conducting a burn. Regulation No. 9 also contains a number of factors the State must consider in determining whether and, if so, under what conditions, a permit may be granted. Some of the factors the State must consider include: the potential contribution of such burning to air pollution in the area; the meteorological conditions on the day or days of the proposed burning; the location of the proposed burn and smoke-sensitive areas and Class I areas that might be impacted by the smoke and emissions from the burn; whether the applicant will conduct the burn in accordance with a smoke management plan or narrative that requires that best smoke management methods will be used to minimize or eliminate smoke impacts at smoke-sensitive receptors (including Class I areas); and that the burn will be scheduled outside times of significant visitor use in smoke-sensitive receptor areas that may be impacted by smoke and emissions from the fire.

The regulation requires all prescribed fire permitees to submit an application to the State. The State only grants a permit if the State's assessment demonstrates that under the prescribed meteorological conditions for the burn there will be no unacceptable air pollution, including visibility impacts. The regulation provides for the State to impose permit conditions necessary to ensure that the burn will be conducted to minimize the impacts of the fire on visibility and on public health and welfare. Permitted sources are also required to report actual activity to the State. Depending on the size and type of fire, reporting may be a daily requirement. At a minimum, permitted sources must report yearly to the State with information indicating whether

[29] The State has determined that agricultural burning is not a significant source of emissions related to regional haze impairment. For example, the State estimates that in 2004 only 503 tpy of PM_{10} were generated from agricultural burning in the entire State of Colorado. See Colorado TSD document "Agricultural Burning in Colorado, 2003 and 2004 Inventories."

or not there was any activity in the area covered by the permit and, if so, how many acres were burned.

Colorado inputs fire data into the WRAP Fire Emissions Tracking System (FETS). The FETS gives the State more precise information for future inventories and studies. The State commits in this SIP to continue administration of Regulation 9 as part of this LTS, and to input data into the FETS as long as it is operational.

d. Emission Limitations and Schedules for Compliance

The State has included the emission limitations and compliance schedules for those sources specifically identified for control in this RH SIP in Chapters 6 and 8, Regulation No. 3, Part F and Regulation No.7, Section XVII.E.3.a. For the BART sources, Regulation No. 3, section VI.A contains the emission limitations for each of the sources and provides that sources must comply as expeditiously as possible, but no later than five-years from EPA approval of the SIP. For RP sources, Regulation No. 3, section VI.B, contains the emission limitations for each of the sources and provides that sources must comply no later than December 31, 2017. For the PSCO BART alternative, Regulation No. 3, section VI.C, contains the emission limitations and the compliance deadlines for sources covered by the PSCO BART alternative. Regulation No. 7, Section XVII.E.3.a contains the compliance schedule for RB RICE over 500 hp.

We are proposing to approve the emission limits and compliance schedules contained in Regulation No. 3, sections VI.A, VI.B, and VI.C.

e.Sources Retirement and Replacement Schedules

The State has included specific information on source retirement for those sources specifically identified for shutdown in its RH SIP. The State has identified the sources in the PSCO BART alternative that will shut down. Specifically, under the PSCO BART alternative, the following units will be retired: Arapahoe Unit 3 by December 31, 2013; Cherokee Unit 1 by July 1, 2012, Cherokee Unit 2 by December 31, 2011, Cherokee Unit 3 by December 31, 2016, and Valmont by December 31, 2017. The shutdown of the sources under the BART alternative is required by the RH SIP (see Chapter 6.4.3.7 of the SIP and Regulation No. 3, Part F, SectionVI.C). Under RP, PSCO Cameo Station and Black Hills Clark Facility Units 1 and 2 will be, or have already, shut down. The shutdown of these RP sources is required by the RH SIP (see Chapter 8.5.2 of the SIP and Regulation No. 3, Part F, Section VI.B). The State is assuming that all other stationary sources evaluated in the SIP will remain in operation through the end of this planning period.

The State is also assuming mobile source fleet turnover. For mobile sources, the turnover of the fleet from older, higher-emitting vehicles to newer, lower-emitting vehicles is captured in the emission inventory presented in section V.E.1 of this notice. The State developed the fleet turnover rate utilizing EPA-approved methodologies.

f. Enforceability of Colorado's Measures

Section 51.308(d)(3)(v)(f) of the RHR requires States to ensure that emission limitations and control measures used to meet RPGs are enforceable. In addition to what is required by the RHR, general SIP requirements mandate that the SIP must also include adequate monitoring, recordkeeping, and reporting requirements for the RH emission limits and requirements. (see CAA section 110(a)). As noted above, Chapters 6 and 8 of the SIP and Regulation No. 3, Part F, Sections VI.A, VI.B, and VI.C, specify BART, RP, and BART alternative emission limits and compliance schedules. The State is submitting Regulation No. 3, Part F, Section VI, as part of the RH SIP.

Regulation No. 3, Part F, Section VII, specifies monitoring, recordkeeping, and reporting requirements for BART, RP, and BART alternative units. The State is submitting Regulation No. 3, Part F, Section VII, as part of its RH SIP. Colorado worked closely with EPA in developing these requirements. For SO_2 and NO_x limits, Colorado has required sources to use continuous emission monitoring systems (CEMS) that must be operated and maintained in accordance with relevant EPA regulations, in particular, 40 CFR part 75 or 40 CFR part 60. For PM limits, Regulation No. 3 requires that sources perform testing in accordance with EPA approved test methods and that sources have a compliance assurance monitoring plan developed and approved in accordance with 40 CFR part 64. Regulation No. 3, Part F, Section VII, requires that sources keep relevant records for five years, and that sources report excess emissions on a semi-annual basis.

g. Anticipated Net Effect on Visibility Due to Projected Changes

The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions during this planning period is addressed in section V.D.3 of this notice.

Based on our analysis, we have determined the State is meeting the long-term strategy requirements under 40 CFR 51.308(d)(3)(v). EPA is proposing to approve the State's long-term strategy found in Chapter 9 of the SIP. In addition, EPA is proposing to approve Regulation No. 3, Part F, Section VI and Section VII.

F. Coordination of RAVI and Regional Haze Rule Requirements

Our visibility regulations direct states to coordinate their RAVI long-term strategy and monitoring provisions with those for RH, as explained in section IV.F above. Under our RAVI regulations, the RAVI portion of a state SIP must address any integral vistas identified by the FLMs pursuant to 40 CFR 51.304 (see 40 CFR 51.302). An integral vista is defined in 40 CFR

51.301 as a view perceived from within the mandatory Class I Federal area of a specific landmark or panorama located outside the boundary of the mandatory Class I Federal area. Visibility in any mandatory Class I Federal area includes any integral vista associated with that area. The long-term strategy must have the capability of addressing current and future existing impairment situations as they face the state.

Regulation No. 3, Part D, Section XIV provides FLMs the opportunity to certify whether an existing stationary source(s) is reasonably attributable to existing visibility impairment and potentially subject to BART and provides the State's review schedule for the RAVI long-term strategy. The EPA previously approved the State's 2004 RAVI long-term strategy as meeting the requirements of 40 CFR 51.306 (see 71 FR 64465). In order to coordinate the RH long-term strategy and the RAVI long-term strategy, the State submitted revisions to Regulation No. 3, Part D, Section XIV. The State amended Regulation No. 3, Part D, Section XIV.F as part of this SIP action to change the current three-year RAVI long-term strategy review cycle to a five-year cycle (as required by the RH Rule) to coordinate the RAVI and RH elements together as intended by the RH rule.

We propose to find that the RH SIP appropriately supplements and augments Colorado's RAVI provisions by updating the monitoring and long-term strategy provisions to address RH. We discuss the relevant monitoring provisions further below. We are also proposing to approve the revision to Regulation No. 3, Part D, Section XIV.F, to change the review period from three years to five years to coordinate with the five-year periodic review required by the RH Rule.

G. Monitoring Strategy and Other Implementation Plan Requirements

40 CFR 51.308(d)(4) requires that the SIP contain a monitoring strategy for measuring, characterizing, and reporting RH visibility impairment that is representative of all mandatory

Class I Federal areas within the state. This monitoring strategy must be coordinated with the monitoring strategy required in 40 CFR 51.305 for RAVI. As 40 CFR 51.308(d)(4) notes, compliance with this requirement may be met through participation in the IMPROVE network. 40 CFR 51.308(d)(4)(i) further requires the establishment of any additional monitoring sites or equipment needed to assess whether RPGs to address RH for all mandatory Class I Federal areas within the state are being achieved.

Consistent with EPA's monitoring regulations for RAVI and RH, Colorado indicates in Chapter 3 of the RH SIP that it will rely on the IMPROVE network for compliance purposes, in addition to any additional visibility impairment monitoring that may be needed in the future. The IMPROVE monitors at the Colorado Class I Areas are described in section IV.B of this notice.

Section 51.308(d)(4)(ii) requires that Colorado establish procedures by which monitoring data and other information are used in determining the contribution of emissions from within Colorado to RH visibility impairment at mandatory Class I Federal areas both within and outside the state. The IMPROVE monitoring program is national in scope, and other states have similar monitoring and data reporting procedures, ensuring a consistent and robust monitoring data collection system. As 40 CFR 51.308(d)(4) indicates, Colorado's participation in the IMPROVE program constitutes compliance with this requirement.

Section 51.308(d)(4)(iv) requires that the SIP provide for the reporting of all visibility monitoring data to the Administrator at least annually for each mandatory Class I Federal area in the state. To the extent possible, Colorado should report visibility monitoring data electronically. Section 51.308(d)(4)(vi) also requires that the SIP provide for other elements, including reporting, recordkeeping, and other measures, necessary to assess and report on visibility. We propose that Colorado's participation in the IMPROVE network ensures that the monitoring data is reported at least annually and is easily accessible; therefore, such participation complies with this requirement. IMPROVE data are centrally compiled and made available to EPA, states and the public via various electronic formats and websites including IMPROVE (http://vista.cira.colostate.edu/improve/) and VIEWS (http://vista.cira.colostate.edu/views/).

Section 51.308(d)(4)(v) requires that Colorado maintain a statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any mandatory Class I Federal area. The inventory must include emissions for a baseline year, emissions for the most recent year for which data are available, and estimates of future projected emissions. The state must also include a commitment to update the inventory periodically. The State's emission inventory is discussed in section V.E.1 above. Chapter 3 of the SIP states that Colorado will update its portion of the regional inventory on the tri-annual cycle as dictated by the Air Emissions Reporting Rule in order to track emission change commitments and trends as well as for input to regional modeling exercises.

Section 51.308(d)(4)(vi) requires that states provide for any additional reporting, recordkeeping, and measures necessary to evaluate and report on visibility. The State has committed to provide any additional reporting, recordkeeping and measures necessary to evaluate and report on visibility but has concluded that it cannot identify a need for any specific commitment at this time. We agree with the State's conclusion that no specific additional measures are necessary at this time.

We propose to find that Colorado has satisfied the requirements in 40 CFR 51.308(d)(4).

H. Consultation with FLMs

Class I areas in Colorado are managed by either the U.S. Forest Service (FS) or the U.S. National Park Service (NPS). Although the FLMs are very active in participating in the regional planning organizations, the RHR grants the FLMs a special role in the review of the RH SIPs, summarized in section IV.H, above. The FLMs and the state environmental agencies are our partners in the RH process. Under 40 CFR 51.308(i)(2), Colorado was obligated to provide the FS and the NPS with an opportunity for consultation, in person and at least 60 days prior to holding a public hearing on the RH SIP. In development of its 2010 RH SIP submittal, Colorado met with the FS and NPS for consultation on June 2, 2010, August 12, 2010, and October 5, 2010.

Section CFR 51.308(i)(3) requires that Colorado provide in its RH SIP a description of how it addressed any comments provided by the FLMs. The FLMs formally commented on the 2010 proposed SIP in November and December of 2010. The NPS and FS provided support for the modeling approach used by the State in the BART determinations and complimented the State on thorough BART and RP analyses and area source evaluations. The FLMs also presented recommendations that the State reevaluate costs and emission limits for some of the BART and RP sources. Chapter 2.1 of the State's SIP provides more detailed information on the State's response to FLM comments.

Lastly, 40 CFR 51.308(i)(4) specifies the RH SIP must provide procedures for continuing consultation between the state and FLMs on the implementation of the visibility protection program required by 40 CFR 51.308. This includes development and review of implementation plan revisions and five-year progress reports and the implementation of other programs having the potential to contribute to impairment of visibility in mandatory Class I Federal areas. In Chapter 10 of the SIP, the State has included a commitment that it will provide the FLMs an opportunity to review and comment on SIP revisions, the five-year progress reports, and other developing programs that may contribute to Class I visibility impairment. Colorado will afford the FLMs with an opportunity for consultation in person and at least 60 days prior to holding any public hearing on a SIP revision. The FLM consultation must include the opportunity to discuss the FLMs' assessment of visibility impairment in each federal Class I area and to provide recommendations on the development and implementation of the visibility control strategies.

I. Periodic SIP Revisions and 5-year Progress Reports

In accordance with the requirements listed in 40 CFR 51.308(g), Colorado commits in Chapter 10 of its SIP to submit a report on RP to EPA every five years following the initial submittal of the SIP. That report will be in the form of an implementation plan revision. The State's report will evaluate the progress made towards the RPGs for each mandatory Class I area located within Colorado and in each mandatory Class I area located outside Colorado, which have been identified as being affected by emissions from Colorado. The State will also evaluate the monitoring strategy adequacy in assessing RPGs.

Based on the findings of the five-year progress report, 40 CFR 51.308(h) requires a state to make a determination of adequacy of the current implementation plan. The State must take one or more of the actions listed in 40 CFR 51. 308(h)(1) through (4) that are applicable at the same time as the state submits a five-year progress report. Colorado commits in Chapter 10 of the SIP to determine the adequacy of the current SIP at the same time a five-year progress report is due.

Section CFR 51.308(f) requires a state to revise and submit its RH SIP to EPA by July 31, 2018, and every ten years thereafter. The State commits in Chapter 10 of the SIP to provide this revision and to evaluate and reassess elements required under 40 CFR 51.308(d), taking into account improvements in monitoring data collection and analysis, and control technologies.

VI. EPA's Proposed Action

EPA is proposing to approve a SIP revision submitted by the State of Colorado on May 25, 2011 that addresses RH. EPA is proposing to determine that the plan submitted by Colorado satisfies requirements of the CAA and our rules under 40 CFR 51.308 that require states to prevent any future and remedy any existing man-made impairment of visibility in mandatory Class I areas. We are proposing to approve the State's RH SIP, including revisions submitted as part of the RH SIP to:

- Regulation No. 3, Part F, Section VI and Section VII.
- Regulation No. 3, Part D, Section XIV.F.
- Regulation No. 7, Section XVII.E.3.a.

VII. Statutory and Executive Order Reviews

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

- Is not a "significant regulatory action" subject to review by the Office of Management and Budget under Executive Order 12866 (58 FR 51735, October 4, 1993);
- Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 USC 3501 et seq.);

- Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 USC 601 et seq.);
- Does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Public Law 104-4);
- Does not have Federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);
- is not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);
- Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001);
- Is not subject to requirements of Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 USC 272 note) because application of those requirements would be inconsistent with the CAA; and,
- Does not provide EPA with the discretionary authority to address, as appropriate, disproportionate human health or environmental effects, using practicable and legally permissible methods, under Executive Order 12898 (59 FR 7629, February 16, 1994).

In addition, this rule does not have Tribal implications as specified by Executive Order 13175 (65 FR 67249, November 9, 2000), because the SIP is not approved to apply in Indian country located in the State, and EPA notes that it will not impose substantial direct costs on Tribal governments or preempt Tribal law.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Intergovernmental relations, Nitrogen dioxide, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides, Volatile organic compounds.

Dated: March 8, 2012

James B. Martin
Regional Administrator
Region 8

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