Exh. DCG-21
Dockets UE-200900, UG-200901,
UE-200894
Witness: David C. Gomez

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **AVISTA CORPORATION, d/b/a AVISTA UTILITIES,** **Respondent.**	**DOCKETS UE-200900, UG-200901, UE-200894 (*Consolidated*)**

EXHIBIT TO
TESTIMONY OF

David C. Gomez

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

EPA Montana Regional Haze Plan Proposed Rules, April 20, 2012,
and Final Rules, September 18, 2012

April 21, 2021

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Part III

Environmental Protection Agency

40 CFR Part 52
Approval and Promulgation of Implementation Plans; State of Montana; State Implementation Plan and Regional Haze Federal Implementation Plan; Proposed Rule

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R08–OAR–2011–0851; FRL–9655–7]

Approval and Promulgation of Implementation Plans; State of Montana; State Implementation Plan and Regional Haze Federal Implementation Plan

AGENCY: Environmental Protection Agency.

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing a Federal Implementation Plan (FIP) to address regional haze in the State of Montana. EPA developed this proposal in response to the State's decision in 2006 to not submit a regional haze State Implementation Plan (SIP) revision. EPA is proposing to determine that the FIP satisfies requirements of the Clean Air Act (CAA or ''the Act'') that require states, or EPA in promulgating a FIP, to assure reasonable progress towards the national goal of preventing any future and remedying any existing man-made impairment of visibility in mandatory Class I areas. In addition, EPA is also proposing to approve a revision to the Montana SIP submitted by the State of Montana through the Montana Department of Environmental Quality on February 17, 2012. The State's submittal contains revisions to the Montana Visibility Plan that includes amendments to the ''Smoke Management'' section, which adds a reference to Best Available Control Technology (BACT) as the visibility control measure for open burning as currently administered through the State's air quality permit program. This change was made to meet the requirements of the Regional Haze Rule. EPA will act on the remaining revisions in the State's submittal in a future action.

DATES: Written comments must be received at the address below on or before June 19, 2012.

Public Hearings. We will be holding two public hearings for this proposal. One hearing is scheduled to be held in Helena, Montana on Tuesday, May 1, 2012 from 2 p.m. until 5:30 p.m. and from 6:30 p.m. until 9 p.m. at the Lewis & Clark Library, 120 S. Last Chance Gulch, Helena, Montana 59601, (406) 447–1690. The other hearing is scheduled to be held in Billings, Montana on Wednesday, May 2, 2012 from 1 p.m. until 5 p.m. and from 6 p.m. until 8 p.m. at the Montana State University—Downtown Campus, Meeting Room—Broadway III A, 2804 3rd Avenue North, Billings, Montana 59101, (406) 896–5860.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R08–OAR–2011–0851, by one of the following methods:

- *http://www.regulations.gov.* Follow the on-line instructions for submitting comments.
- *Email: r8airrulemakings@epa.gov.*
- *Fax:* (303) 312–6064 (please alert the individual listed in **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 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–2011–0851. 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 email. 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 email comment directly to EPA, without going through *http://www.regulations.gov,* your email 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 a.m. to 4 p.m., excluding federal holidays.

FOR FURTHER INFORMATION CONTACT: Vanessa Hinkle, Air Program, U.S. Environmental Protection Agency, Region 8, Mailcode 8P–AR, 1595 Wynkoop, Denver, Colorado 80202–1129, (303) 312–6561, *hinkle.vanessa@epa.gov.*

SUPPLEMENTARY INFORMATION:

Table of Contents

Definitions

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 *A/F* mean or refer to air-to-fuel.
iii. The initials *ARM* mean or refer to Administrative Rule of Montana.
iv. The initials *ARP* mean or refer to the acid rain program.
v. The initials *ASOFA* mean or refer to advanced separated overfire air.
vi. The initials *BACT* mean or refer to Best Available Control Technology.
vii. The initials *BART* mean or refer to Best Available Retrofit Technology.
viii. The initials *CAMD* mean or refer to EPA Clean Air Markets Division.
ix. The initials *CAMx* mean or refer to Comprehensive Air Quality Model.
x. The initials *CCM* mean or refer to EPA Control Cost Manual.
xi. The initials *CCOFA* mean or refer to close-coupled overfire air system.
xii. The initials *CDS* mean or refer to circulating dry scrubber.
xiii. The initials *CELP* mean or refer to Colstrip Energy Limited Partnership.
xiv. The initials *CEMS* mean or refer to continuous exhaust monitoring systems.
xv. The initials *CEPCI* mean or refer to Chemical Engineering Plant Cost Index.
xvi. The initials *CFAC* mean or refer to Columbia Falls Aluminum Company.
xvii. The initials *CFB* mean or refer to circulating fluidized bed.
xviii. The initials *CKD* mean or refer to cement kiln dust.
xix. The initials *CMAQ* mean or refer to Community Multi-Scale Air Quality modeling system.
xx. The initials *CO* mean or refer to carbon monoxide.
xxi. The initials *CPI* mean or refer to Consumer Price Index.
xxii. The initials *CRF* mean or refer to Capital Recovery Factor.
xxiii. The initials *DAA* mean or refer to Dry Absorbent Addition.
xxiv. The initials *DPCS* mean or refer to digital process control system.
xxv. The initials *D–R* mean or refer to Dresser-Rand.
xxvi. The initials *DSI* mean or refer to dry sorbent injection.
xxvii. The initials *EC* mean or refer to elemental carbon.
xxviii. The initials *EGU* mean or refer to Electric Generating Units.
xxix. The words *EPA, we, us* or *our* mean or refer to the United States Environmental Protection Agency.
xxx. The initials *ESP* mean or refer to electrostatic precipitator.
xxxi. The initials *FCCU* mean or refer to fluid catalytic cracking unit.
xxxii. The initials *FGD* mean or refer to flue gas desulfurization.
xxxiii. The initials *FGR* mean or refer to flue gas recirculation.
xxxiv. The initials *FIP* mean or refer to Federal Implementation Plan.
xxxv. The initials *FLMs* mean or refer to Federal Land Managers.
xxxvi. The initials *HAR* mean or refer to hydrated ash reinjection.
xxxvii. The initials *HDSCR* mean or refer to high-dust selective catalytic reduction.
xxxviii. The initials *HC* mean or refer to hydrocarbons.
xxxix. The initials *IMPROVE* mean or refer to Interagency Monitoring of Protected Visual Environments monitoring network.
xl. The initials *IPM* mean or refer to Integrated Planning Model.
xli. The initials *LDSCR* mean or refer to low-dust selective catalytic reduction.
xlii. The initials *LEA* mean or refer to low excess air.
xliii. The initials *LNBs* mean or refer to low NO_X burners.
xliv. The initials *LSD* mean or refer to lime spray drying.
xlv. The initials *LSFO* mean or refer to limestone forced oxidation.
xlvi. The initials *LTS* mean or refer to Long-Term Strategy.
xlvii. The initials *MDEQ* mean or refer to Montana's Department of Environmental Quality.
xlviii. The initials *MDF* mean or refer to medium density fiberboard.
xlix. The initials *MISO* mean or refer to Midwest Independent Transmission System Operator.
l. The initials *MDU* mean or refer to Montana-Dakota Utilities Company.
li. The initials *MKF* mean or refer to mid-kiln firing of solid fuel.
lii. The words *Montana* and *State* mean the State of Montana.
liii. The initials *MSCC* mean or refer to Montana Sulphur and Chemical Company.
liv. The initials *NEI* mean or refer to National Emission Inventory.
lv. The initials *NESHAP* mean or refer to National Emission Standards for Hazardous Air Pollutants.
lvi. The initials NH_3 mean or refer to ammonia.
lvii. The initials NO_X mean or refer to nitrogen oxides.
lviii. The initials *NP* mean or refer to National Park.
lix. The initials *NSCR* mean or refer to non-selective catalytic reduction.
lx. The initials *NSPS* mean or refer to New Source Performance Standards.
lxi. The initials *NWR* mean or refer to National Wildlife Reserve.
lxii. The initials *OC* mean or refer to organic carbon.
lxiii. The initials *OFA* mean or refer to overfire air.
lxiv. The initials *PC* mean or refer to pulverized coal.
lxv. The initials *PH/PC* mean or refer to preheater/precalciner.
lxvi. The initials *PM* mean or refer to particulate matter.
lxvii. The initials $PM_{2.5}$ mean or refer to particulate matter with an aerodynamic diameter of less than 2.5 micrometers (fine particulate matter).

lxviii. The initials PM_{10} mean or refer to particulate matter with an aerodynamic diameter of less than 10 micrometers (coarse particulate matter).
lxix. The initials *PMCD* mean or refer to particulate matter control device.
lxx. The initials *ppm* mean or refer to parts per million.
lxxi. The initials *PRB* mean or refer to Powder River Basin.
lxxii. The initials *PSAT* mean or refer to Particulate Matter Source Apportionment Technology.
lxxiii. The initials *PSD* mean or refer to Prevention of Significant Deterioration.
lxxiv. The initials *RAVI* mean or refer to Reasonably Attributable Visibility Impairment.
lxxv. The initials *RICE* mean or refer to Reciprocating Internal Combustion Engines.
lxxvi. The initials *RMC* mean or refer to Regional Modeling Center.
lxxvii. The initials *ROFA* mean or refer to rotating opposed fire air.
lxxviii. The initials *RP* mean or refer to Reasonable Progress.
lxxix. The initials *RPG* or *RPGs* mean or refer to Reasonable Progress Goal(s).
lxxx. The initials *RPOs* mean or refer to regional planning organizations.
lxxxi. The initials *RRI* mean or refer to rich reagent injection.
lxxxii. The initials *RSCR* mean or refer to regenerative selective catalytic reduction.
lxxxiii. The initials *SCOT* mean or refer to Shell Claus Off-Gas Treatment.
lxxxiv. The initials *SCR* mean or refer to selective catalytic reduction.
lxxxv. The initials *SDA* mean or refer to spray dryer absorbers.
lxxxvi. The initials *SIP* mean or refer to State Implementation Plan.
lxxxvii. The initials *SMOKE* mean or refer to Sparse Matrix Operator Kernel Emissions.
lxxxviii. The initials *SNCR* mean or refer to selective non-catalytic reduction.
lxxxix. The initials SO_2 mean or refer to sulfur dioxide.
xc. The initials *SOFA* mean or refer to separated overfire air.
xci. The initials *SRU* mean or refer to sulfur recovery unit.
xcii. The initials *TESCR* mean or refer to tail-end selective catalytic reduction.
xciii. The initials *TCEQ* mean or refer to Texas Commission on Environmental Quality.
xciv. The initials *tpy* mean tons per year.
xcv. The initials *TSD* mean or refer to Technical Support Document.
xcvi. The initials *URP* mean or refer to Uniform Rate of Progress.
xcvii. The initials *VOC* mean or refer to volatile organic compounds.
xcviii. The initials *WA* mean or refer to Wilderness Area.
xcic. The initials *WEP* mean or refer to Weighted Emissions Potential.
c. The initials *WRAP* mean or refer to the Western Regional Air Partnership.
ci. The initials *YELP* mean or refer to Yellowstone Energy Limited Partnership.

I. General Information

The public hearings will provide interested parties the opportunity to present information and opinions to EPA concerning our proposal. Interested parties may also submit written comments, as discussed in the proposal. Written statements and supporting information submitted during the comment period will be considered with the same weight as any oral comments and supporting information presented at the public hearing. We will not respond to comments during the public hearing. When we publish our final action, we will provide written responses to all oral and written comments received on our proposal.

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

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 email. 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 a FIP for the State of Montana (State) to address regional haze. In so doing, EPA is proposing to determine that the federal plan along with the change to Montana's visibility plan, submitted on February 17, 2012, that requires BACT as the visibility control measure for open burning satisfy the requirements of 40 CFR 51.308.

III. Background

A. Regional Haze

Regional haze is visibility impairment that is produced by a multitude of sources and activities which are located across a broad geographic area and emit fine particulates ($PM_{2.5}$) (e.g., sulfates, nitrates, organic carbon (OC), elemental carbon (EC), and soil dust), and their precursors (e.g., sulfur dioxide (SO_2), nitrogen oxides (NO_X), and in some cases, ammonia (NH_3) and volatile organic compounds (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 (NP) and wilderness areas (WA). The average visual range [1] in many Class I areas (i.e., NPs and memorial parks, WA, and international parks meeting certain size criteria) in the western United States is 100–150

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

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

In section 169A of the 1977 Amendments to the CAA, Congress created a program for protecting visibility in the nation's national parks and wilderness areas. This section of the CAA establishes as a national goal the ''prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas [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 (December 2, 1980). These regulations represented the first phase in addressing visibility impairment. EPA deferred action on regional haze that emanates from a variety of sources until monitoring, modeling and scientific knowledge about the relationships between pollutants and visibility impairment were improved.

Congress added section 169B to the CAA in 1990 to address regional haze issues. EPA promulgated a rule to address regional haze on July 1, 1999. 64 FR 35714 (July 1, 1999), codified at 40 CFR part 51, subpart P. The Regional Haze Rule revised the existing visibility regulations to integrate into the regulation provisions addressing regional haze impairment and established a comprehensive visibility protection program for Class I areas. The requirements for regional haze, found at 40 CFR 51.308 and 51.309, are included in EPA's visibility protection regulations at 40 CFR 51.300–309. Some of the main elements of the regional haze requirements are summarized in this section of this preamble. The requirement to submit a regional haze SIP applies to all 50 states, the District of Columbia and the Virgin Islands.[3] 40 CFR 51.308(b) requires states to submit the first implementation plan addressing regional haze visibility impairment no later than December 17, 2007.[4]

Few states submitted a Regional Haze SIP prior to the December 17, 2007 deadline, and on January 15, 2009, EPA found that 37 states, including Montana and the District of Columbia, and the Virgin Islands, had failed to submit SIPs addressing the regional haze requirements. 74 FR 2392 (January 15, 2009). 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 regional haze 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, or the EPA when implementing a FIP, 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 regional haze 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 regional haze 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 regional haze.

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 regional haze, 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 a Regional Haze FIP

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

A. The CAA and the Regional Haze Rule

Regional haze FIPs must assure Reasonable Progress 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, or EPA when implementing a FIP, to establish long-term strategies for making Reasonable Progress toward meeting this goal. The FIP 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 regional haze FIP requirements are discussed in further detail below.

B. EPA's Authority To Promulgate a FIP

On June 19, 2006, Montana submitted a letter to us signifying that the State would be discontinuing its efforts to revise the visibility control plan that would have incorporated provisions of

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

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

the Regional Haze Rule.[5] The State acknowledged with this letter that EPA would make a finding of failure to submit and thus promulgate additional federal rules to address the requirements of the Regional Haze Rule, including BART. In response to the State's decision EPA made a finding of SIP inadequacy on January 15, 2009 (74 FR 2392), determining that Montana failed to submit a SIP that addressed any of the required regional haze SIP elements of 40 CFR 51.308.

Under section 110(c) of the Act, whenever we find that a State has failed to make a required submission we are required to promulgate a FIP. Specifically, section 110(c) provides:

''(1) The Administrator shall promulgate a Federal implementation plan at any time within 2 years after the Administrator—

(A) finds that a State has failed to make a required submission or finds that the plan or plan revision submitted by the State does not satisfy the minimum criteria established under [section 110(k)(1)(A)], or

(B) disapproves a State implementation plan submission in whole or in part, unless the State corrects the deficiency, and the Administrator approves the plan or plan revision, before the Administrator promulgates such Federal implementation plan.''

Section 302(y) defines the term ''Federal implementation plan'' in pertinent part, as:

''[A] plan (or portion thereof) promulgated by the Administrator to fill all or a portion of a gap or otherwise correct all or a portion of an inadequacy in a State implementation plan, and which includes enforceable emission limitations or other control measures, means or techniques (including economic incentives, such as marketable permits or auctions or emissions allowances) * * *.''

Thus, because the State withdrew their efforts to revise the visibility control plan that would have incorporated provisions of the Regional Haze Rule and we determined the State failed to submit the SIP, we are required to promulgate a FIP.

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

The Regional Haze Rule establishes the deciview as the principal metric or unit for expressing visibility. *See* 70 FR 39104, 39118 (July 6, 2005). 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 deciviews is determined by using air quality measurements to estimate light extinction and then transforming the value of light extinction using a logarithm function. The deciview is a more useful measure for tracking progress in improving visibility than light extinction itself because each deciview change is an equal incremental change in visibility perceived by the human eye. Most people can detect a change in visibility at one deciview.[6]

The deciview is used in expressing Reasonable Progress Goals (which are interim visibility goals towards meeting the national visibility goal), defining baseline, current, and natural conditions, and tracking changes in visibility. The regional haze FIPs 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 regional haze. 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 Reasonable Progress, states, or EPA when implementing a FIP, must calculate the degree of existing visibility impairment at each Class I area at the time of each regional haze SIP submittal and periodically review progress every five years midway through each 10-year implementation period. To do this, the Regional Haze Rule requires states, or EPA when implementing a FIP, to determine the degree of impairment (in deciviews) for the average of the 20% least impaired (''best'') and 20% most impaired (''worst'') visibility days over a specified time period at each of their Class I areas. In addition, states, or EPA if implementing a FIP, must also develop an estimate of natural visibility conditions for the purpose of comparing progress toward the national goal. Natural visibility is determined by estimating the natural concentrations of pollutants that cause visibility impairment and then calculating total light extinction based on those estimates. We have provided guidance regarding how to calculate baseline, natural and current visibility conditions.[7]

For the first regional haze SIPs that were due by December 17, 2007, ''baseline visibility conditions'' were the starting points for assessing ''current'' visibility impairment. If a state does not submit this SIP, EPA will implement a FIP to cover this requirement. Baseline visibility conditions represent the degree of visibility impairment for the 20% least impaired days and 20% most impaired days for each calendar year from 2000 to 2004. Using monitoring data for 2000 through 2004, states, or EPA if implementing a FIP, 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 to 2004 baseline period is considered the time from which improvement in visibility is measured.

D. Determination of Reasonable Progress Goals (RPGs)

The vehicle for ensuring continuing progress toward achieving the natural visibility goal is the submission of a series of regional haze 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). However, if a state does not submit a SIP for any of these requirements, then EPA shall implement a FIP. The Regional Haze Rule does not mandate specific milestones or rates of progress, but instead requires EPA to establish goals that provide for ''reasonable progress'' towards achieving natural (*i.e.,* ''background'') visibility conditions. In setting RPGs, EPA must provide for an improvement in visibility for the most

[5] Letter from Richard H. Opper, Director Montana Department of Environmental Quality (further referred to as MDEQ) to Laurel Dygowski, EPA Region Air Program, June 19, 2006.

[6] The preamble to the Regional Haze Rule provides additional details about the deciview. 64 FR 35714, 35725 (July 1, 1999).

[7] *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/RegionalHaze_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'').

impaired days over the (approximately) 10-year period of the FIP, and ensure no degradation in visibility for the least impaired days over the same period. *Id.*

In establishing RPGs, states, or EPA if implementing a FIP, are required to consider the following factors established in section 169A of the CAA and in our Regional Haze Rule 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. EPA must demonstrate in our FIP, 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, EPA must also consider the rate of progress needed to reach natural visibility conditions by 2064 (referred to as the ''uniform rate of progress'' or the ''glidepath'') and the emission reduction measures needed to achieve that rate of progress over the 10-year period of the FIP. Uniform progress towards achievement of natural conditions by the year 2064 represents a rate of progress which EPA is to use for analytical comparison to the amount of progress we expect to achieve. In setting RPGs, EPA must also consult with potentially ''contributing states,'' *i.e.,* other nearby states with emission sources that may be affecting visibility impairment at Montana's Class I areas. 40 CFR 51.308(d)(1)(iv). In determining whether EPA's goals for visibility improvement provide for Reasonable Progress toward natural visibility conditions, EPA is required to evaluate the demonstrations developed through our FIP, pursuant to paragraphs 40 CFR 51.308(d)(1)(i) and (d)(1)(ii). 40 CFR 51.308(d)(1)(iii).

E. Best Available Retrofit Technology (BART)

Section 169A of the CAA directs states, or EPA if implementing a FIP, 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 EPA to implement a FIP to contain such measures as may be necessary to make Reasonable Progress towards the natural visibility goal, including a requirement that certain categories of existing major stationary sources [8] built between 1962 and 1977 procure, install, and operate the ''Best Available Retrofit Technology'' as determined by EPA. Under the Regional Haze Rule, EPA is 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, EPA also has the flexibility to adopt an emissions trading program or other alternative program as long as the alternative provides greater Reasonable Progress towards improving visibility than BART.

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, or EPA if implementing a FIP, 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 (July 6, 2005). In making a BART determination for a fossil fuel-fired electric generating plant with a total generating capacity in excess of 750 megawatts (MW), EPA must use the approach set forth in the BART Guidelines. EPA 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, EPA must meet the requirements of the CAA and our regulations for selection of BART, and EPA's BART analysis and determination must be reasonable in light of the overarching purpose of the regional haze program.

The process of establishing BART emission limitations can be logically broken down into three steps: first, EPA identifies those sources which meet the definition of ''BART-eligible source'' set forth in 40 CFR 51.301; [9] second, EPA determines 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, EPA then identifies the best available type and level of control for reducing emissions.

States, or EPA if implementing a FIP, 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 we should use our best judgment in determining whether VOC or NH_3 compounds impair visibility in Class I areas.

Under the BART Guidelines, states, or EPA if implementing a FIP, 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. EPA must document this exemption threshold value in the FIP, and must state the basis for our 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. EPA 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 EPA should not be higher than 0.5 deciviews. 40 CFR part 51, appendix Y, section III.A.1.

A regional haze FIP, must include source-specific BART emission limits and compliance schedules for each source subject to BART. Once EPA 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 the final FIP. CAA section 169(g)(4) and 40 CFR 51.308(e)(1)(iv). In addition to what is required by the Regional Haze Rule, general SIP, or FIP, requirements mandate that the SIP, or FIP, 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 Regional Haze Rule allows EPA to implement an alternative program in lieu of BART so long as the alternative program can be demonstrated to achieve greater Reasonable Progress toward the national visibility goal than would BART.

F. Long-Term Strategy (LTS)

Consistent with the requirement in section 169A(b) of the CAA that states, or EPA if implementing a FIP, include in the regional haze SIP, or FIP, a 10 to 15 year strategy for making Reasonable Progress, section 51.308(d)(3) of the Regional Haze Rule requires that states, or EPA if implementing a FIP, include a LTS in the regional haze SIP, or FIP. The LTS is the compilation of all control measures that will be used during the implementation period of the FIP to meet applicable RPGs. The LTS must include ''enforceable emissions limitations, compliance schedules, and

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

[9] 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.

other measures as necessary to achieve the reasonable progress goals'' for all Class I areas within, or affected by emissions from, the state of Montana. 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 Regional Haze Rule requires the impacted state, or EPA if implementing a FIP, to coordinate with the contributing states in order to develop coordinated emissions management strategies. 40 CFR 51.308(d)(3)(i). In such cases, EPA must demonstrate that it has included in its FIP, 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, or EPA if implementing a FIP, may be required to sufficiently address interstate visibility issues. This is especially true where two states belong to different RPOs.

States, or EPA if implementing a FIP, should consider all types of anthropogenic sources of visibility impairment in developing their LTS, including stationary, minor, mobile, and area sources. At a minimum, EPA must describe how each of the following seven factors listed below are taken into account in developing our LTS: (1) Emission reductions due to ongoing air pollution control programs, including measures to address Reasonably Attributable Visibility Impairment; (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).

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

As part of the Regional Haze Rule, 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 regional haze 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 regional haze, and the state must submit the first such coordinated LTS with its first regional haze SIP. If the state does not revise its plan in the appropriate amount of time, EPA shall implement a FIP to address this requirement. 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 regional haze and RAVI impairment and must be submitted to EPA as a SIP revision. However, if the state does not provide future coordinated LTS and periodic progress reports towards RPGs then EPA will cover this by implementing a FIP.

H. Monitoring Strategy and Other Implementation Plan Requirements

Section 51.308(d)(4) of the Regional Haze Rule includes the requirement for a monitoring strategy for measuring, characterizing, and reporting of regional haze 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 regional haze SIP, and it must be reviewed every five (5) years. The monitoring strategy must also provide for additional monitoring sites if the IMPROVE network is not sufficient to determine whether RPGs will be met.

Under section 51.308(d)(4), 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 regional haze 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 regional haze 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 Regional Haze Rule 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 Regional Haze SIP. Facilities subject to BART must continue to comply with the BART provisions of section 51.308(e). Periodic SIP revisions will assure that the statutory requirement of reasonable progress will continue to be met.

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

The Regional Haze Rule requires that states, or EPA if implementing a FIP, consult with FLMs before adopting and submitting their SIPs, or FIPs. 40 CFR 51.308(i). EPA must provide FLMs an opportunity for consultation, in person and at least 60 days prior to holding any public hearing on the FIP. 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, EPA must include in its FIP, a description of how it addressed any comments provided by the FLMs. Finally, a FIP must provide procedures for continuing consultation between EPA and FLMs regarding EPA's FIP, visibility protection program, including development and review of FIP 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 Analysis of Montana's Regional Haze

A. Affected Class I Areas

In accordance with 40 CFR 51.308(d), we have identified 12 Class I areas within Montana: Anaconda-Pintler WA, Bob Marshall WA, Cabinet Mountains WA, Gates of the Mountains WA, Glacier NP, Medicine Lake WA, Mission Mountain WA, Red Rock Lakes WA, Scapegoat WA, Selway-Bitterroot WA, U.L. Bend WA and Yellowstone NP. EPA is responsible for developing RPGs for these 12 Class I areas. EPA has also determined that Montana emissions have or may reasonably be expected to have impacts at Class I areas in other states including: Badlands WA, Bridger WA, Craters of the Moon WA, Fitzpatrick WA, Grand Teton NP, Hells Canyon WA, Lostwood National Wildlife Reserve (NWR), North Absaroka NP, Teton WA, Theodore Roosevelt NP, Washakie WA and Wind Cave NP. This determination was based on Particulate Matter Source Apportionment Technology (PSAT) and Weighted Emissions Potential (WEP) analysis and is further described in Table 150.

EPA worked with the appropriate state air quality agency in each of these states through our involvement with the WRAP. The WRAP is a collaborative effort of tribal governments, state governments and various federal agencies to implement the Grand Canyon Visibility Transport Commission's recommendations and to develop the technical and policy tools needed by western states and tribes to comply with the U.S. EPA's regional haze regulations. Assessment of Montana's contribution to haze in these Class I areas is based on technical analyses developed by WRAP as discussed in this notice.

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

As required by section 51.308(d)(2)(i) of the Regional Haze Rule and in accordance with our 2003 Natural Visibility Guidance, EPA calculated baseline/current and natural visibility conditions for the Montana Class I areas, Anaconda-Pintler WA, Bob Marshall WA, Cabinet Mountains WA, Gates of the Mountains WA, Glacier NP, Medicine Lake WA, Mission Mountain WA, Red Rock Lakes WA, Scapegoat WA, Selway-Bitterroot WA, U.L. Bend WA and Yellowstone NP on the most impaired and least impaired days, as summarized below (and further described in the docket).[10] The natural visibility conditions, baseline visibility conditions, and visibility impact reductions needed to achieve the Uniform Rate of Progress (URP) in 2018 for all Montana Class I areas are presented in Table 1 and further explained in this section.

TABLE 1—VISIBILITY IMPACT REDUCTIONS NEEDED BASED ON BEST AND WORST DAYS BASELINES, NATURAL CONDITIONS, AND UNIFORM RATE OF PROGRESS GOALS FOR MONTANA CLASS I AREAS

Montana class I area	20% Worst days				20% Best days	
	2000–2004 Baseline (deciview)	2018 URP Goal (deciview)	2018 Reduction needed (delta deciview)	2064 Natural conditions (deciview)	2000–2004 Baseline (deciview)	2064 Natural conditions (deciview)
Anaconda-Pintler WA	13.41	12.02	1.39	7.43	2.58	1.12
Bob Marshall WA	14.48	12.91	1.57	7.73	3.85	1.48
Cabinet Mountains WA	14.09	12.56	1.53	7.52	3.62	1.48
Gates of the Mountains WA	11.29	10.15	1.14	6.38	1.71	0.32
Glacier NP	22.26	19.21	3.05	9.18	7.22	2.42
Medicine Lake WA	17.72	15.42	2.30	7.89	7.26	2.96
Mission Mountain WA	14.48	12.91	1.57	7.73	3.85	1.48
Red Rock Lakes WA	11.76	10.52	1.24	6.44	2.58	0.43
Scapegoat WA	14.48	12.91	1.57	7.73	3.85	1.48
Selway-Bitterroot WA	13.41	12.02	1.39	7.43	2.58	1.12
U.L. Bend WA	15.14	13.51	1.63	8.16	4.75	2.45
Yellowstone NP	11.76	10.52	1.24	6.44	2.58	0.43

1. Estimating Natural Visibility Conditions

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 the use of ''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 IMPROVE equation'' that was adopted for use by the IMPROVE Steering Committee in December 2005 and the Natural Conditions II algorithm that was finalized in May 2007.[11] The purpose of this refinement to the ''old IMPROVE equation'' is to provide more

[10] Information presented here was taken from the WRAP TSS (*http://vista.cira.colostate.edu/tss/*). Some of this information was printed and is available in the docket in the document titled Selected Information from the WRAP TSS (''WRAP TSS Information'').

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

accurate estimates of the various factors that affect the calculation of light extinction.

For all 12 Class I Areas in Montana, EPA opted to use WRAP calculations in which the default estimates for the natural conditions (see Table 2) were combined with the ''new IMPROVE equation'' and the Natural Conditions II algorithm (see Table 3). This is an acceptable approach under our 2003 Natural Visibility Guidance. Table 2 shows the default natural visibility values for the 20% worst days and 20% best days.

TABLE 2—DEFAULT NATURAL VISIBILITY VALUES FOR THE 20% BEST DAYS AND 20% WORST DAYS

Class I area	20% Worst days	20% Best days
Anaconda-Pintler WA	7.28	2.16
Bob Marshall WA	7.36	2.24
Cabinet Mountains WA	7.43	2.31
Gates of the Mountains WA	7.22	2.10
Glacier NP	7.56	2.44
Medicine Lake WA	7.30	2.18
Mission Mountain WA	7.39	2.27
Red Rock Lakes WA	7.14	2.02
Scapegoat WA	7.29	2.17
Selway-Bitterroot WA	7.32	2.20
U.L. Bend WA	7.18	2.06
Yellowstone NP	7.12	2.00

EPA also referred to WRAP calculations using the new IMPROVE equation. Table 3 shows the natural visibility values for each Class I Area for the 20% worst days and 20% best days using the new IMPROVE Equation and Natural Conditions II algorithm.

TABLE 3—VISIBILITY VALUES FOR THE 20% BEST DAYS AND 20% WORST DAYS USING THE NEW IMPROVE EQUATION

Class I area	20% Worst days	20% Best days
Anaconda-Pintler WA	7.43	1.12
Bob Marshall WA	7.73	1.48
Cabinet Mountains WA	7.52	1.48
Gates of the Mountains WA	6.38	0.32
Glacier NP	9.18	2.42
Medicine Lake WA	7.89	2.96
Mission Mountain WA	7.73	1.48
Red Rock Lakes WA	6.44	0.43
Scapegoat WA	7.73	1.48
Selway-Bitterroot WA	7.43	1.12
U.L. Bend WA	8.16	2.45
Yellowstone NP	6.44	0.43

The new IMPROVE equation takes into account the most recent review of the science [12] and accounts for the effect of particle size distribution on light extinction efficiency of sulfate, nitrate, and OC. It also adjusts the mass multiplier for OC (particulate organic matter) by increasing it from 1.4 to 1.8. New terms are added to the equation to account for light extinction by sea salt and light absorption by gaseous nitrogen dioxide. Site-specific values are used for Rayleigh scattering (scattering of light due to atmospheric gases) to account for the site-specific effects of elevation and temperature. Separate relative humidity enhancement factors are used for small and large size distributions of ammonium sulfate and ammonium nitrate and for sea salt. The terms for the remaining contributors, EC (light-absorbing carbon), fine soil, and coarse mass terms, do not change between the original and new IMPROVE equations.

2. Estimating Baseline Conditions

As required by section 51.308(d)(2)(i) of the Regional Haze Rule and in accordance with our 2003 Natural Visibility Guidance, EPA calculated baseline visibility conditions for Anaconda-Pintler WA, Bob Marshall WA, Cabinet Mountains WA, Gates of the Mountains WA, Glacier NP, Medicine Lake WA, Mission Mountain WA, Red Rock Lakes WA, Scapegoat WA, Selway-Bitterroot WA, U.L. Bend WA and Yellowstone NP. The baseline condition calculation begins with the calculation of light extinction, using the IMPROVE equation. The IMPROVE equation sums the light extinction [13] resulting from individual pollutants, such as sulfates and nitrates. As with the natural visibility conditions calculation, EPA chose to use the new IMPROVE equation.

The period for establishing baseline visibility conditions is 2000 through 2004, and baseline conditions must be calculated using available monitoring data. 40 CFR 51.308(d)(2). This FIP proposes to use visibility monitoring data collected by IMPROVE monitors located in all Montana Class I areas for the years 2000 through 2004 and the resulting baseline conditions represent an average for 2000 through 2004. Table 4 shows the baseline conditions for each Class I area.

TABLE 4—BASELINE CONDITIONS ON 20% WORST DAYS AND 20% BEST DAYS

Class I area	20% Worst days	20% Best days
Anaconda-Pintler WA	13.41	2.58
Bob Marshall WA	14.48	3.85
Cabinet Mountains WA	14.09	3.62
Gates of the Mountains WA	11.29	1.71
Glacier NP	22.26	7.22
Medicine Lake WA	17.72	7.26
Mission Mountain WA	14.48	3.85
Red Rock Lakes WA	11.76	2.58
Scapegoat WA	14.48	3.85
Selway-Bitterroot WA	13.41	2.58
U.L. Bend WA	15.14	4.75
Yellowstone NP	11.76	2.58

3. Summary of Baseline and Natural Conditions

To address the requirements of 40 CFR 51.308(d)(2)(iv)(A), EPA also calculated the number of deciviews by which baseline conditions exceed natural visibility conditions at each Class I area. Table 5 shows the number of deciviews by which baseline conditions exceed natural visibility conditions at each Class I area.

TABLE 5—NUMBER OF DECIVIEWS BY WHICH BASELINE CONDITIONS EXCEED NATURAL VISIBILITY CONDITIONS

Class I area	20% Worst days	20% Best days
Anaconda-Pintler WA	5.98	1.46
Bob Marshall WA	6.75	2.37
Cabinet Mountains WA	6.57	2.14
Gates of the Mountains WA	4.91	1.39
Glacier NP	13.08	4.8
Medicine Lake WA	9.83	4.3
Mission Mountain WA	6.75	2.37
Red Rock Lakes WA	5.32	2.15
Scapegoat WA	6.75	2.37
Selway-Bitterroot WA	5.98	1.46

[12] The science behind the revised IMPROVE equation is summarized in our technical support document (TSD), in the TSD for Technical Products Prepared by the WRAP in Support of Western Regional Haze Plans (''WRAP TSD''), February 28, 2011, and in numerous published papers. See for example: Hand, J.L., and Malm, W.C., 2006, *Review of the IMPROVE Equation for Estimating Ambient Light Extinction Coefficients—Final Report.* March 2006. Prepared for IMPROVE, Colorado State University, Cooperative Institute for Research in the Atmosphere, Fort Collins, Colorado, *available at http://vista.cira.colostate.edu/improve/publications/GrayLit/016_IMPROVEeqReview/IMPROVEeqReview.htm* and Pitchford, March 2006, *Natural Haze Levels II: Application of the New IMPROVE Algorithm to Natural Species Concentrations Estimates.* Final Report of the Natural Haze Levels II Committee to the RPO Monitoring/Data Analysis Workgroup. September 2006, *available at http://vista.cira.colostate.edu/improve/Publications/GrayLit/029_NaturalCondII/naturalhazelevelsIIreport.ppt.*

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

TABLE 5—NUMBER OF DECIVIEWS BY WHICH BASELINE CONDITIONS EXCEED NATURAL VISIBILITY CONDITIONS—Continued

Class I area	20% Worst days	20% Best days
U.L. Bend WA	6.98	2.3
Yellowstone NP	5.32	2.15

4. Uniform Rate of Progress

In setting the RPGs, EPA reviewed and relied on the WRAP analysis to analyze and determine the URP needed to reach natural visibility conditions by the year 2064. In so doing, the analysis compared the baseline visibility conditions in each Class I area to the natural visibility conditions in each Class I area (as described above) and determined the URP needed in order to attain natural visibility conditions by 2064 in all Class I areas. The analysis constructed the URP consistent with the requirements of the Regional Haze Rule and consistent with our 2003 Tracking Progress Guidance by plotting a straight graphical line from the baseline level of visibility impairment for 2000 through 2004 to the level of visibility conditions representing no anthropogenic impairment in 2064 for each Class I area. The URPs are summarized in Table 6. It is clear from Table 6 that there is a large range of baseline and natural visibility conditions across the 12 Class I areas in Montana. The degree of improvement to meet the URP at these sites varies from, 1.24 deciviews at Yellowstone NP to 3.05 deciviews at Glacier NP.

TABLE 6—SUMMARY OF UNIFORM RATE OF PROGRESS FOR 20% WORST DAYS

Class I area	Baseline conditions (deciview)	Natural visibility (deciview)	Total improvement by 2064 (deciview)	URP (deciview/year)	2018 URP target (deciview)	Improvement by 2018 (deciview)
Anaconda-Pintler WA	13.41	7.43	5.98	0.10	12.02	1.39
Bob Marshall WA	14.48	7.73	6.75	0.11	12.91	1.57
Cabinet Mountains WA	14.09	7.52	6.57	0.11	12.56	1.53
Gates of the Mountains WA	11.29	6.38	4.91	0.08	10.15	1.14
Glacier NP	22.26	9.18	13.08	0.22	19.21	3.05
Medicine Lake WA	17.72	7.89	9.83	0.16	15.42	2.3
Mission Mountain WA	14.48	7.73	6.75	0.11	12.91	1.57
Red Rock Lakes WA	11.76	6.44	5.32	0.09	10.52	1.24
Scapegoat WA	14.48	7.73	6.75	0.11	12.91	1.57
Selway-Bitterroot WA	13.41	7.43	5.98	0.10	12.02	1.39
U.L. Bend WA	15.14	8.16	6.98	0.12	13.51	1.63
Yellowstone NP	11.76	6.44	5.32	0.09	10.52	1.24

5. Contribution Assessment According to IMPROVE Monitoring Data

The visibility and pollutant contributions on the 20% worst visibility days for the baseline period (2000–2004) show considerable variation across the 12 Class I areas in Montana. Table 7 shows average data from the IMPROVE monitors for 2000 to 2004.[14] The table shows light extinction from specific pollutants as well as total extinction, as determined by the monitoring data. As stated above, this data provides further detail regarding the considerable variation across the 12 Class I areas in Montana.

TABLE 7—SPECIES-SPECIFIC LIGHT EXTINCTION DETERMINED FROM MONITORING DATA

Class I area	Deciview	Sulfate	Nitrate	Organic carbon	Elemental carbon	Soil	Sea salt	Coarse matter	Total extinction
Anaconda-Pintler WA	13.41	4.83	1.46	20.01	2.52	0.94	0.26	2.49	42.52
Bob Marshall WA	14.48	5.12	1.43	22.29	2.80	1.29	0.03	3.60	46.58
Cabinet Mountains WA	14.09	6.48	2.02	16.95	2.79	1.03	0.10	2.81	42.18
Gates of the Mountains WA	11.29	5.41	1.88	11.26	1.82	0.75	0.06	1.68	31.85
Glacier NP	22.26	11.37	9.36	87.68	11.20	1.40	0.28	5.22	137.50
Medicine Lake WA	17.72	16.96	16.27	9.48	2.34	0.75	0.03	4.46	61.30
Mission Mountains WA	14.48	5.12	1.43	22.29	2.80	1.29	0.03	3.60	46.58
Red Rock Lakes WA	11.76	4.26	1.77	13.48	2.48	0.95	0.02	2.58	34.55
Scapegoat WA	14.48	5.12	1.43	22.29	2.80	1.29	0.03	3.60	46.58
Selway-Bitterroot WA	13.41	4.83	1.46	20.01	2.52	0.94	0.26	2.49	42.52
U.L. Bend WA	15.14	9.78	8.01	12.76	2.08	0.77	0.01	4.01	48.43
Yellowstone NP	11.76	4.26	1.77	13.48	2.48	0.95	0.02	2.58	34.55

The poorest visibility on the 20% worst days was at Glacier NP at 22.26 deciviews, while the best visibility was at Gates of the Mountains WA at 11.26 deciviews. Fire appears to be a major factor contributing to the spatial differences. The five-year average contributions in Table 7 indicate that Glacier NP has significantly higher contributions from organic carbon mass than Gates of the Mountains WA. The daily monitoring data for Glacier NP shows an episode of exceptionally high organic carbon mass during August 2003 that indicates a fire event. This single episode influenced the five-year average values for Glacier NP.

[14] Additional data and information can be found at: *http://views.cira.colostate.edu/web/DataFiles/SummaryDataFiles.aspx.*

C. BART Determinations

BART is an element of EPA's LTS for the first implementation period. As discussed in more detail in section IV.E of this preamble, the BART evaluation process consists of three components: (1) An identification of all the BART-eligible sources; (2) an assessment of whether those BART-eligible sources are in fact subject to BART; and (3) a determination of any BART controls. EPA 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. While Montana did not submit a SIP, the State did provide some useful information; and as discussed below, we are proposing it as our conclusion.

EPA used some information and analyses developed by Montana as described below.

Montana identified the following 10 sources to be BART-eligible: ASARCO LLC East Helena Plant; Ash Grove Cement Company; Cenex Harvest States Cooperative; Laurel Refinery; PPL Montana, LLC; Colstrip Steam Electric Station Units 1 and 2; Columbia Falls Aluminum Company, LLC; ExxonMobil Refining & Supply Company Billings Refinery; Holcim (US), Inc,; Montana Sulfur & Chemical Company; and Smurfit-Stone Container Enterprises Inc, Missoula Mill.[15] Montana originally identified ASARCO LLC East Helena Plant as BART-eligible; however, the emission units at the facility have since been demolished. Thus, we are proposing that the ASARCO LLC East Helena Plant is not BART-eligible.[16]

The State identified the BART-eligible sources in Montana by utilizing the approach set out in the BART Guidelines (70 FR 39158 (July 6, 2005)); [17] 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(s) began operation on or after August 6, 1962, and was in existence on August 6, 1977; and (3) potential emissions of any visibility-impairing pollutant from subject units are 250 tons or more per year. Montana initially screened its records to identify facilities that could potentially meet the three criteria in the BART Guidelines (70 FR 39158 (July 6, 2005)). Montana contacted the sources identified through its screening efforts, through a series of letters, to obtain or confirm this information.[18]

The WRAP also reviewed facility information to identify BART-eligible sources. The WRAP used the Preliminary 2002 National Emission Inventory (NEI) to identify all facilities whose actual emissions exceed 100 tons per year (tpy) or more of any visibility-impairing pollutant. The WRAP added sources to this preliminary list if they were identified by the states or tribes; found in various CAA Title V, U.S. Department of Energy, and EPA databases; or found in EPA background documents such as those prepared for New Source Performance Standards (NSPS), maximum achievable control technology standards, and AP–42 emission factors. The WRAP then considered category, date of construction, and PTE information to determine eligibility. The results from this analysis identified facilities as BART-eligible, potentially BART-eligible, not known, or not BART-eligible.[19]

We have reviewed the ''Master List of Montana Sources Reviewed'' in the report titled ''Identification of BART Eligible Sources in the WRAP Region'' dated April 4, 2005. We propose to determine that the following nine facilities identified as BART-eligible by the State and the WRAP are BART-eligible: Ash Grove Cement Company; Cenex Harvest States Cooperative, Laurel Refinery; PPL Montana, LLC, Colstrip Steam Electric Station Units 1 and 2; Columbia Falls Aluminum Company, LLC; ExxonMobil Refining & Supply Company Billings Refinery; Holcim (US); Inc, Montana Sulfur & Chemical Company; and Smurfit-Stone Container Enterprises Inc, Missoula Mill. We propose to determine that the other facilities identified in the WRAP's April 4, 2005 list as ''potentially BART-eligible'', ''not known'', or ''not BART-eligible'' are not BART-eligible.

The BART Guidelines require that we address SO_2, NO_X, and direct PM (including both coarse particulate matter (PM_{10}) and $PM_{2.5}$) emissions as visibility-impairing pollutants and to exercise our ''best judgment to determine whether VOC or ammonia emissions from a source are likely to have an impact on visibility in an area.'' See 70 FR 39160, July 6, 2005. VOCs and NH_3 from point sources are not significant visibility-impairing pollutants at Montana's Class I areas. Point sources contribute less than 1% to Montana's inventory for both NH_3 and VOC emissions.[20] As a result, we have determined that the emissions from these point sources do not merit BART review.

We are proposing that the nine Montana facilities listed in Table 8 are the BART-eligible sources in the State.

TABLE 8—LIST OF BART-ELIGIBLE SOURCES IN MONTANA

BART-eligible source	Location	BART Source category (SC)	Nearest class I area
1. Ash Grove Cement Company ...	Montana City, western Montana ..	Portland cement plants	Gates of the Mountains WA 30 km.
2. Cenex Harvest States Cooperatives Laurel Refinery.	Laurel, central Montana	Petroleum refineries	North Absaroka WA 113 km.
3. PPL Montana, LLC Colstrip Steam Electric Station (Unit 1 and Unit 2).	Colstrip, southeastern Montana ...	Fossil-fuel fired steam electric plants of more than 250 million BTUs per hour heat input.	U.L. Bend WA 200 km.
4. Columbia Falls Aluminum Company, LLC.	Columbia Falls, northwestern Montana.	Primary aluminum ore reduction plants.	Glacier NP 10 km.
5. ExxonMobil Refinery & Supply Company, Billings Refinery.	Billings, central Montana	Petroleum refineries	North Absaroka WA 143 km.

[15] This list can be found in the docket with the title, Montana BART-Eligible Facility List.

[16] Correspondence between ASARCO LLC and EPA can be found in the docket in the file titled ASARCO Correspondence.

[17] The flow charts that Montana used to identify BART-eligible sources are included in the docket in a file titled Montana BART Flow Charts.

[18] Examples of the letters sent to the Montana facilities are included in the docket in a file titled Montana Letters.

[19] The WRAP's work is documented in the document titled, ''Identification of BART-Eligible Sources in the WRAP Region'' dated April 4, 2005. The ''Master List of Montana Sources Reviewed'' in this report is a second document from the one that is referred to in a previous footnote titled, ''Montana BART-Eligible Facility List''.

[20] WRAP TSS Information.

TABLE 8—LIST OF BART-ELIGIBLE SOURCES IN MONTANA—Continued

BART-eligible source	Location	BART Source category (SC)	Nearest class I area
6. Holcim (US), Inc.	Three Forks, western Montana	Portland cement plants	Yellowstone NP 100 km.
7. PPL Montana, LLC—JE Corette Steam Electric Station.	Billings, central Montana	Fossil-fuel fired steam electric plants of more than 250 million BTUs per hour heat input.	North Absaroka WA 137 km.
8. Montana Sulfur & Chemical Company.	Billings, central Montana	Chemical process plants	North Absaroka WA 143 km.
9. Smurfit-Stone Container Enterprises Inc., Missoula Mill.	Missoula, northwestern Montana	Kraft pulp mills and fossil fuel boilers of more than 250 million BTUs per hour heat input.	Selway-Bitterroot WA 32 km.

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 us 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, the WRAP performed dispersion modeling to assess the extent of each BART-eligible source's contribution to visibility impairment at surrounding Class I areas and we propose to use that modeling.

a. Modeling Methodology

The BART Guidelines provide that we may use the CALPUFF [21] modeling system or another appropriate model to predict the visibility impacts from a single source on a Class I area and to, therefore, determine whether an individual source is anticipated to cause or contribute to impairment of visibility in Class I areas, *i.e.,* ''is subject to BART.'' The Guidelines state that we find CALPUFF is the best regulatory modeling application currently available for predicting a single source's contribution to visibility impairment (70 FR 39162 (July 6, 2005)).

The BART Guidelines also recommend that a modeling protocol be developed for making individual source attributions. To determine whether each BART-eligible source has a significant impact on visibility, we propose to use the WRAP's modeling that used the CALPUFF model to estimate daily visibility impacts above estimated natural conditions at each Class I area within 300 kilometers (km) of any BART-eligible facility, based on maximum actual 24-hour emissions over a 3-year period (2000–2002). The modeling followed the WRAP protocol, CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States, August 15, 2006, which was approved by EPA.[22]

b. Contribution Threshold

For the 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 39161, July 5, 2005. 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 or EPA 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 and EPA 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.

EPA proposes to use a contribution threshold of 0.5 deciviews for determining which sources are subject to BART. EPA's proposal considered the numerous sources affecting the Class I areas and the magnitude of the individual sources impacts. 70 FR 39121, July 6, 2005. As shown in Table 9, EPA proposes to exempt four of the nine BART-eligible sources in the State from further review under the BART requirements. The visibility impacts attributable to each of these three sources fell well below 0.5 deciviews. Our proposed contribution threshold captures those sources responsible for most of the total visibility impacts, while still excluding other sources with very small impacts. *Id.*

c. Sources Identified by EPA as BART–Eligible and Subject to BART

The results of the CALPUFF modeling are summarized in Table 9. Those facilities listed with demonstrated impacts at all Class I areas less than 0.5 deciviews are proposed by EPA to not be subject to BART; those with impacts greater than 0.5 deciviews are proposed by EPA to be subject to BART.

[21] Note that our reference to CALPUFF encompasses the entire CALPUFF modeling system, which includes the CALMET, CALPUFF, and CALPOST models and other pre and post processors. The different versions of CALPUFF have corresponding versions of CALMET, CALPOST, etc. which may not be compatible with previous versions (e.g., the output from a newer version of CALMET may not be compatible with an older version of CALPUFF). The different versions of the CALPUFF modeling system are available from the model developer at *http://www.src.com/calpuff/calpuff1.htm.*

[22] This approval is described on p. 57 of the WRAP TSD. The WRAP protocol, CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States, August 15, 2006 can be found in the docket.

TABLE 9—INDIVIDUAL BART-ELIGIBLE SOURCE VISIBILITY IMPACTS ON MONTANA CLASS I AREAS

Source and unit	Class I area	Maximum 24-hour 98th percentile visibility impact (deciview)	Subject to BART or exempt
1. Ash Grove Cement Company	Gates of the Mountains WA	2.52	Subject to BART.
	Scapegoat WA	0.42	
	Anaconda-Pintler WA	0.09	
	Bob Marshall WA	0.39	
	Mission Mountains WA	0.06	
	Selway-Bitterroot WA	0.01	
	Yellowstone NP	0.01	
	Red Rock Lakes WA	0.00	
	Theodore Roosevelt NP	0.10	
	North Absaroka WA	0.00	
	Washakie WA	0.00	
	Teton WA	0.00	
2. Cenex Harvest States Cooperatives, Laurel Refinery.	North Absaroka WA	0.04	Exempt.
	Yellowstone NP	0.02	
	Washakie WA	0.03	
	Teton WA	0.01	
	U.L. Bend WA	0.00	
	Red Rocks Lake WA	0.00	
	Gates of the Mountains WA	0.00	
3. PPL Montana, LLC Colstrip Steam Electric Station Units 1 and 1.	U.L. Bend WA	2.52	Subject to BART.
	North Absaroka WA	1.35	
	Theodore Roosevelt NP	2.28	
	Washakie WA	0.69	
	Yellowstone NP	0.86	
4. Columbia Falls Aluminum Company, LLC	Glacier NP	4.54	Subject to BART.
	Bob Marshall WA	0.11	
	Mission Mountains WA	0.08	
	Cabinet Mountains WA	0.12	
	Scapegoat WA	0.05	
	Selway-Bitterroot WA	0.03	
	Gates of the Mountains WA	0.03	
	Anaconda-Pintler WA	0.02	
5. ExxonMobil Refinery & Supply Company, Billings Refinery.[23]	North Absaroka WA	0.27	Exempt.
	Yellowstone NP	0.17	
	Washakie WA	0.22	
	U.L. Bend WA	0.23	
	Teton WA	0.10	
	Gates of the Mountains WA	0.22	
	Red Rock Lakes WA	0.09	
6. Holcim (US), Inc.	Yellowstone NP	0.52	Subject to BART.
	Gates of the Mountains WA	1.02	
	Anaconda-Pintler WA	0.23	
	Red Rock Lakes WA	0.20	
	Scapegoat WA	0.28	
	North Absaroka WA	0.43	
	Bob Marshall WA	0.28	
	Washakie WA	0.11	
	Theodore Roosevelt NP	0.08	
	Selway-Bitterroot WA	0.15	
	Mission Mountains WA	0.12	
	Glacier NP	0.11	
7. PPL Montana, LLC-JE Corette Steam Electric Station.	North Absaroka WA	0.74	Subject to BART.
	Yellowstone NP	0.45	
	Washakie WA	0.53	
	U.L. Bend WA	0.91	
	Teton WA	0.22	
	Gates of the Mountains WA	0.52	
	Red Rock Lakes WA	0.21	
8. Montana Sulfur & Chemical Company	North Absaroka WA	0.22	Exempt.
	Yellowstone NP	0.17	
	Washakie WA	0.16	
	U.L. Bend WA	0.30	
	Teton WA	0.08	
	Gates of the Mountains WA	0.19	

TABLE 9—INDIVIDUAL BART-ELIGIBLE SOURCE VISIBILITY IMPACTS ON MONTANA CLASS I AREAS—Continued

Source and unit	Class I area	Maximum 24-hour 98th percentile visibility impact (deciview)	Subject to BART or exempt
9. Smurfit-Stone Container Enterprises Inc., Missoula Mill.	Red Rock Lakes WA	0.09	Exempt.
	Selway-Bitterroot WA	0.23	
	Mission Mountains WA	0.36	
	Bob Marshall WA	0.23	
	Scapegoat	0.21	
	Anaconda-Pintler WA	0.07	
	Cabinet Mountains WA	0.14	
	Glacier NP	0.19	
	Gates of the Mountains WA	0.11	
	Hells Canyon WA	0.01	
	Eagles Cap Wilderness	0.00	

[23] Exxon Mobil submitted revised modeling dated November 29, 2007 (''Exxon Correspondence''), which is the basis for our analysis and is available in the docket.

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 (July 6, 2005)) 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;
- 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, or EPA if implementing a FIP, must consider the five statutory factors in section 169A of the CAA: (1) The costs of compliance; (2) the energy and non-air quality environmental impacts of compliance; (3) any existing pollution control technology in use at the source; (4) the remaining useful life of the source; and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. See also 40 CFR 51.308(e)(1)(ii)(A). The actual visibility impact analysis occurs during steps 4 and 5 of the process.

a. Visibility Improvement Modeling

The fifth factor to consider under EPA's BART Guidelines is the degree of visibility improvement from the BART control options. *See* 59 FR 39170 (August 1, 1994). The BART Guidelines recommend using the CALPUFF air quality dispersion modeling system to estimate the visibility improvements of alternative control technologies at each Class I area, typically those within a 300 km radius of the source, and to compare these to each other and to the impact of the baseline (*i.e.,* current) source configuration. The CALPUFF modeling system is comprised of the CALMET data which is used to pre-process meteorological data; the CALPUFF model which is used to simulate the conversion of pollutant emissions to $PM_{2.5}$ and the transport and fate of $PM_{2.5}$; and the CALPOST processor which is used to calculate visibility impairments at receptors sites.

The BART Guidelines recommend comparing visibility improvements between control options using the 98th percentile of 24-hour delta deciviews, which is equivalent to the facility's 8th highest visibility impact day. The 98th percentile is recommended rather than the maximum value to allow for uncertainty in the modeled impacts and to avoid undue influence from unusual meteorological conditions. The ''delta'' refers to the difference between total deciview impact from the facility plus natural background, and deciviews of natural background alone, so ''delta deciviews'' is the estimate of the facility's impact relative to natural visibility conditions. Visibility is traditionally described in terms of visual range in kilometers or miles. However, the visual range scale does not correspond to how people perceive visibility because how a given increase in visual range is perceived depends on the starting visibility against which it is compared. Thus, an increase in visual range may be perceived to be a big improvement when starting visibility is poor, but a relatively small improvement when starting visibility is good.

The ''deciview'' scale is designed to address this problem. It is linear with respect to perceived visibility changes over its entire range, and is analogous to the decibel scale for sound. This means that a given change in deciviews will be perceived as the same amount of visibility change regardless of the starting visibility. Lower deciview values represent better visibility and greater visual range, while increasing deciview values represent increasingly poor visibility. In the BART Guidelines, EPA determined that ''a 1.0 deciview change or more from an individual source would cause visibility impairment, and a change of 0.5 deciviews would contribute to impairment. Generally, 0.5 deciviews is equivalent to a 5% change in perceived visibility and is the amount of change that will evoke a just noticeable change in most landscapes.'' [24] Converting a 5% change in light extinction to a change in deciviews yields a change of approximately 0.5 deciviews.

Under the BART Guidelines, the improved visibility in deciviews from installing controls is determined by using the CALPUFF air quality model. CALPUFF, generally, simulates the transport and dispersion of emissions, and the conversion of SO_2 to particulate sulfate and NO_X to particulate nitrate, at a rate dependent on meteorological conditions and background ozone concentration. These concentrations are then converted to delta deciviews by the CALPOST post-processor. The CALPUFF modeling system is available and documented at EPA's Model Distribution Web page.[25]

The ''delta deciviews'' for control options estimated by the modeling represents a BART source's impact on visibility at the Class I areas under

[24] BART Guidelines, 70 FR 39120 (July 6, 2005).

[25] EPA's Model Distribution Web page available at: *http://www.epa.gov/ttn/scram/dispersion_prefrec.htm#calpuff.*

different control scenarios. Each modeled day and location in the Class I area will have an associated delta deciviews for each control option. For each day, the model finds the maximum visibility impact of all locations (*i.e.,* receptors) in the Class I area. From among these daily values, the BART Guidelines recommend use of the 98th percentile, for comparing the base case and the effects of various controls.

As part of the FIP development efforts, EPA determined that CALPUFF modeling was needed to evaluate emissions scenarios that would be consistent with the application of controls for Montana sources that were subject to BART.[26] EPA contracted with the University of North Carolina and its subcontractor, Alpine Geophysics, to perform CALPUFF model simulations for BART sources in Montana. The University of North Carolina developed a modeling protocol that EPA approved. The protocol outlines the data sets, models and procedures that were used in the new CALPUFF modeling for BART sources.[27] The evaluated Class I areas that were included in the modeling domain for each BART source are listed in Table 2 of the modeling protocol. The final report from this modeling effort is available in the docket.[28]

The BART determination guidelines recommend that visibility impacts should be estimated in deciviews relative to natural background conditions. CALPOST uses background concentrations of various pollutants to calculate the natural background visibility impact. EPA used background concentrations from Table 2–1 of ''Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule.'' Although the concentration for each pollutant is a single value for the year, this method allows for monthly variation in its visibility impact, which changes with relative humidity.

[26] CALPUFF model simulations had previously been performed for some MT BART sources for certain emissions scenarios using meteorological data sets for the period 2001–2003 that were developed by the WRAP. ''CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States'', available at *http://pah.cert.ucr.edu/aqm/308/bart/WRAP_RMC_BART_Protocol_Aug15_2006.pdf.*

The WRAP data sets were developed in 2006 using the CALPUFF model versions and EPA guidance available at that time.

[27] ''Modeling Protocol: Montana Regional Haze Federal Implementation Plan (FIP) Support'', University of North Carolina, Contract EP–D–07–102, November 14, 2011.

[28] Modeling Report: Montana Regional Haze Federal Implementation Plan (FIP) Support, March 16, 2012.

b. BART Five-Factor Determinations and Federally Enforceable Limits

i. Ash Grove Cement

Background

The Ash Grove Cement (Ash Grove) cement plant near Montana City was determined to be subject to the BART requirements as explained in section V.C. As explained in section V.C., the document titled ''Identification of BART Eligible Sources in the WRAP Region'' dated April 4, 2005 provides more details on the specific emission units at each facility. Our analysis focuses on the long wet kiln as the primary source of SO_2 and NO_X emissions.

We requested a five factor BART analysis for Ash Grove Cement and the company submitted that analysis along with updated information.[29] Ash Grove's five factor BART analysis is contained in the docket for this action and we have taken it into consideration in our proposed action.

NO_X

Step 1: Identify All Available Technologies

We identified that the following NO_X control technologies are available for the kiln at Ash Grove: low NO_X burners (LNB), mid-kiln firing of solid fuel (MKF), cement kiln dust (CKD) insufflation, flue gas recirculation (FGR), selective noncatalytic reduction (SNCR), and selective catalytic reduction (SCR).

LNBs use stepwise or staged combustion and localized exhaust gas recirculation (i.e., at the flame). Staging of combustion air as achieved by such burners is an available control technology for NO_X reduction in cement kilns. In the first stage, fuel combustion is carried out in a high temperature fuel-rich environment and the combustion is completed in the fuel-lean low temperature second stage. By controlling the available oxygen and temperature, LNBs attempt to reduce NO_X formation in the flame zone. LNBs have been used by the cement industry for nearly 30 years and are designed to reduce flame turbulence, delay fuel/air mixing, and establish fuel-rich zones for initial combustion. LNBs can be used in combination with SNCR to achieve even greater emissions reduction.

MKF is a form of secondary combustion where a portion of the fuel is fired in a location other than the burning zone. Ash Grove currently uses a mixture of coal and petroleum coke as the primary fuels for the kiln. A common fuel used for mid kiln firing is scrap tires. By adding fuel mid-kiln, MKF changes both the flame temperature and the flame length. This reduces thermal NO_X formation by burning part of the fuel at a lower temperature by creating reducing conditions at the mid-kiln fuel injection point which may destroy some of the NO_X formed upstream in the kiln burning zone.

CKD insufflation is a residual byproduct that can be produced by any of the four basic types of cement kiln systems. As a means of recycling usable CKD to the cement pyroprocess, CKD can be injected or insufflated into the burning zone of the rotary kiln in or near the main flame. The presence of these cold solids within or in close proximity to the flame cools the flame and/or the burning zone thereby reducing the formation of thermal NO_X.

FGR involves the use of oxygen-deficient flue gas from some point in the process as a substitute for primary air in the main burner pipe in the rotary kiln.[30] FGR lowers the peak flame temperature and develops localized reducing conditions in the burning zone by reducing the oxygen content of the primary combustion air. The intended

[29] The following information has been submitted by Ash Grove: BART Five Factor Analysis Ash Grove Cement Montana City, Montana, Prepared by Trinity Consultants (''Ash Grove BART Analysis'') (June 2007); Letter to Callie Videtich RE: Ash Grove Cement Montana City Plant, Response to Comments on Best Available Retrofit Technology (''Ash Grove Response to Comments''), (February 28, 2008) (note that no redacted information that was claimed to be CBI by Ash Grove was used from this submittal); Letter to Callie Videtich RE: Ash Grove Cement-Montana City Plant, Response to Comments on Best Available Retrofit Technology (''Ash Grove Additional Response to Comments'') (May 5, 2008); Email to Laurel Dygowski from Bob Vantuyl RE: Ash Grove Cement Montana City BART: Cost Analysis for Ash Grove SNCR (''Ash Grove SNCR Cost'') (December 17, 2008); Email to Laurel Dygowski from Bob Vantuyl RE: Ash Grove Cement Montana City Low NO_X Burner Cost Effectiveness (''Ash Grove LNB Cost'') (January 23, 2009); Letter to Vanessa Hinkle from Thomas R. Wood RE: Substantiation for Confidential Business Information Claim for Information Submitted for Best Available Retrofit Technology Analysis (''Ash Grove Additional Information July 2011'') (July 18, 2011); Letter to Vanessa Hinkle from Thomas R. Wood RE: Response to Request for Additional Information for Montana City BART Determination (''Ash Grove Additional Information October 2011'') (October 5, 2011); Email to Vanessa Hinkle from Thomas R. Wood RE: Ash Grove City Cement Company, Montana City Plant (''Ash Grove Additional Information November 2011'') (November 7, 2011); Email to Vanessa Hinkle from Curtis Lesslie RE: DAA Cost Analysis (''Ash Grove DAA Cost Analysis'') (December 20, 2011); Email to Vanessa Hinkle from Curtis Lesslie RE: Ash Grove Montana City BART Analysis Update (''Ash Grove Update January 2012'') (January 19, 2012); Letter to Vanessa Hinkle from Thomas R. Wood RE: Ash Grove Cement Company Response to Supplemental Information Request (''Ash Grove Update March 2012'') (March 9, 2012).

[30] Ash Grove BART Analysis, p. 5–6.

effect is to decrease both thermal and fuel NO_X formation in the rotary kiln.

In SNCR systems, a reagent such as NH_3 or urea is injected into the flue gas at a suitable temperature zone, typically in the range of 1,800 to 2,000 °F and at an appropriate ratio of reagent to NO_X. SNCR system performance depends on temperature, residence time, turbulence, oxygen content, and other factors specific to the given gas stream. SNCR can be used in combination with LNBs to achieve even greater emissions control.

SCR uses either NH_3 or urea in the presence of a metal based catalyst to selectively reduce NO_X emissions. SCR is used in the electric utility industry to reduce NO_X emissions from boilers and has been used on three cement kilns in Europe. SCR is capable of reducing NO_X emissions by about 80%.

Step 2: Eliminate Technically Infeasible Options

Ash Grove estimated that approximately 1.3 million tires would be required to use MKF at the Montana City kiln.[31] There is not a consistent supply of scrap tires of this volume that would be available for the Montana city kiln; therefore, MKF was not considered further.

CKD insufflation can be used at some cement kilns, but can be problematic for others. The cement making process requires a very hot flame to heat the clinkering raw material to about 2,700 °F in as short a time as possible.[32] Because of the increased requirements for thermal energy in the burning zone when insufflation is employed, and the expected increase in fuel required, it is not an attractive technology for wet kiln systems; therefore, CKD insufflation was not considered further.

FGR is used in the electric utility industry, but is not transferrable to cement kilns. For cement kilns, a hot flame is required to complete the chemical reactions that form the clinker minerals from the raw materials. The long/lazy flame that would be produced by FGR would result in the production of unacceptable quality clinker . Clinkering reactions must take place in an oxidizing atmosphere in the burning zone to generate clinker that can be used to produce acceptable cement. FGR would tend to produce localized or general reducing conditions that also could detrimentally affect clinker quality. Adding FGR to a burner that is already designed for optimum flame shaping and control would distort the thermal profile of the kiln, such that product quality would be unacceptably compromised. For these reasons, FGR was not considered further.

SCR has been used on three kilns in Europe; two are preheater kilns, and one kiln is a Polysius Lepol technology kiln, which is a traveling grate preheater kiln. 73 FR 34079 (June 16, 2008). Although we find that SCR is technically feasible for cement kilns, we have not analyzed it further because of the uncertainty regarding control effectiveness and costs. We note that EPA has acknowledged, in the context of establishing the NSPS for Portland Cement Plants, substantial uncertainty regarding the control effectiveness and costs associated with the use of SCR at such plants. See 75 FR 54995 (September 9, 2010). SCR for cement kilns will be re-evaluated in subsequent reasonable progress (RP) planning periods.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

For LNB on Ash Grove's kiln it is appropriate to assume a control effectiveness of 15%.[33] For SNCR, in evaluating the technology, a control effectiveness of 50% is appropriate, and for LNB+SNCR a control effectiveness of 58% is appropriate.

The following discussion is an explanation of why we consider 50% control effectiveness an appropriate estimate for SNCR at long wet kilns, such as Ash Grove's Montana City kiln. Ash Grove has used SNCR at similar wet kilns in Midlothian, TX. Emissions data submitted by Ash Grove to the Texas Commission on Environmental Quality (TCEQ) show that Ash Grove was able to achieve emission rates in the range of 1.6 to 2.9 lb/ton of clinker from June through August 2008 when using SNCR.[34] The emissions reports submitted to the TCEQ indicate that Ash Grove had been using SNCR in 2007 on one of their kilns at Midlothian; however, since the report doesn't specify the exact timeframe we do not know whether the 2007 data can be compared to the June through August 2008 data. Because the emission report data submitted to the TCEQ for SNCR use in 2007 is from an unknown time, we used 2006 emission data from the same three months as the 2008 data—June through August to assess the performance of the SNCR.[35] Table 10 summarizes emission from the Midlothian kilns using the 2006 and 2008 data.

TABLE 10—NO_X EMISSIONS FOR 2006 AND 2008 FOR ASH GROVE CEMENT

	June through August 2006 emission rate (lb/ton clinker)				June through August 2008 emission rate (lb/ton clinker)				Percentage reduction (%)
	June	July	August	Average	June	July	August	Average	
Kiln 1	5.2	5.0	4.5	4.9	1.7	1.6	2.2	1.8	62.5
Kiln 2	5.0	4.1	3.9	4.4	2.7	2.6	2.8	2.7	37.7
Kiln 3	5.0	4.4	4.2	4.5	2.9	2.6	2.5	2.7	40.5

[31] Ash Grove BART Analysis, p. 5–8.

[32] Ash Grove BART Analysis, p. 5–6.

[33] EPA provided an example of LNB on a long wet kiln with a control effectiveness of 14% in NO_X Control Technologies for the Cement Industry, Final Report, September 2000, p. 61.

[34] See the document received from TCEQ available in the docket: Ash Grove Texas, L.P.—Midlothian Plant 2008 Actual Emission Rate Calculations—Kilns, Ash Grove Texas, L.P.—Midlothian Plant 2008 Actual Emission Rate calculations—Input Data.

[35] See the documents received from TCEQ available in the docket: Ash Grove Texas, L.P.—Midlothian Plant 2006 Actual Emission Rate Calculations—Kilns; Ash Grove Texas, L.P.—Midlothian Plant 2006 Actual Emission Rate Calculations—Input Data; Ash Grove Texas, L.P.—Midlothian Plant 2008 Actual Emission Rate Calculations—Kilns, Ash Grove Texas, L.P.—Midlothian Plant 2008 Actual Emission Rate calculations—Input Data.

When the control effectiveness on all three kilns are averaged together, a 47.5% reduction was achieved. This is within the range of control effectiveness values that have been demonstrated at other kilns.[36 37 38]

The concentration of baseline NO_X emissions is one parameter affecting the effectiveness of SNCR. The percentage of control effectiveness is greater when initial NO_X concentrations are greater. The reaction kinetics decrease as the concentration of reactants decreases. This is due to thermodynamic considerations that limit the reduction process at low NO_X concentrations.[39] The baseline NO_X emissions of the Ash Grove Montana City kiln are significantly higher than those at Midlothian,[40] indicating that SNCR on the Montana City kiln would be expected to achieve even greater control effectiveness when compared to SNCR on the Midlothian kilns.

A summary of the emissions projections for the NO_X control options is provided in Table 11.

TABLE 11—SUMMARY OF NO_X BART ANALYSIS CONTROL TECHNOLOGIES FOR ASH GROVE

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
LNB+SNCR	58	1088	803
SNCR	50	946	946
LNB	15	284	1,607
No Controls (Baseline)	0	0	[1] 1,891

[1] Ash Grove LNB Cost.

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

LNB

We relied on cost estimates supplied by Ash Grove for capital costs and annual costs associated with LNB. We present the costs for LNB in Table 12 and 13. For our analysis, we used a capital recovery factor (CRF) consistent with 20 years for the useful life of the kiln. EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. In order to calculate the annualized capital cost, we multiplied the capital cost by the CRF.[41] We summarize the cost information for LNB in Tables 12, 13, and 14.

TABLE 12—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR LNB ON ASH GROVE

Description	Cost ($)
Total Capital Investment	[1] 266,309
Capital Recovery	[2] 25,140

[1] Ash Grove LNB Cost.
[2] Capital Recovery was determined by multiplying the Total Capital Investment by the CRF of 0.0944 which is based on a 7% interest rate and 20 year equipment life. The justification for using the CRF of 0.0944 can be found in Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

TABLE 13—SUMMARY OF NO_X BART ANNUAL COST ANALYSIS FOR LNB ON ASH GROVE

Description	Cost ($)
Total Indirect Annual Cost	[1,2] 65,642
Direct Annual Operating Cost	[2] 92,988
Total Annual Cost	158,630

[1] Includes capital recovery.
[2] Ash Grove LNB Cost.

[36] EPA has stated previously that, ''[o]n average, SNCR achieves approximately a 35 percent reduction in NO_X at a ratio of NH_3-to-NO_X of about 0.5 and a reduction of 63 percent at an NH_3-to-NO_X ratio of 1.0'' in the **Federal Register** notice proposing New Source Performance Standards for Portland cement plants. 73 FR 34078 (June 16, 2008).

[37] The Cadence brochures available at: *http://cadencerecycling.com/sncr.html* and *http://www.cadencerecycling.com/Resources/6–Page Complete.pdf* state that control efficiencies of up to 50% can be achieved on long wet kilns. See also Enhancing SNCR Performance by Induced Mixing, Eric Hansen and Fred Lockwood, December 2006 available at *http://www.cadencerecycling.com/Resources/ICR–Formatted2006.pdf*.

[38] EPA has stated that, ''there are numerous examples of SNCR systems achieving emission reductions greater than 50 percent and as high as 80 percent or more'' in the **Federal Register** notice proposing New Source Performance Standards for Portland cement plants. 73 FR 34079 (June 16, 2008).

[39] EPA's Control Cost Manual (further referred to as CCM) Sixth Edition, January 2002, EPA 452/B–02–001 p. 1–10. The CCM can be found at: *http://www.epa.gov/ttncatc1/dir1/c_allchs.pdf*.

[40] Ash Grove Update March 2012 (Ash Grove's email indicates a mean of 14.4 lbs./ton clinker and a 99th percentile of 18.6 lb NO_X/ton clinker. This is significantly greater than the 2006 emissions shown in Table 10 for the Midlothian kilns.)

[41] Capital Recovery was determined by multiplying the Total Capital Investment by the CRF of 0.0944 which is based on a 7% interest rate and 20 year equipment life. The justification for using the CRF of 0.0944 can be found in Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

TABLE 14—SUMMARY OF NO_X BART COSTS FOR LNB ON ASH GROVE

Control option	Total capital investment ($)	Total annual cost ($)	Annual emissions reductions (tpy)	Average cost effectiveness ($/ton)
LNB	266,309	158,630	284	559

SNCR

We relied on cost estimates supplied by Ash Grove for capital costs and annual costs, with the exception of the CRF. We present the costs for SNCR in Table 15. For our analysis, we used a CRF consistent with 20 years for the useful life of the kiln. EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.[42] In order to calculate the annualized capital cost, we multiplied the capital cost by the CRF.[43] We summarize the cost information from our SNCR analysis in Tables 15, 16, and 17.

TABLE 15—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR SNCR ON ASH GROVE

Description	Cost ($)
Total Capital Investment	[1] 925,324
Capital Recovery	[1,2] 87,351

[1] Ash Grove SNCR Cost.
[2] Capital Recovery was determined by multiplying the Total Capital Investment by the CRF of 0.0944 which is based on a 7% interest rate and 20 year equipment life. The justification for using the CRF of 0.0944 can be found in Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

TABLE 16—SUMMARY OF NO_X BART ANNUAL COST ANALYSIS FOR SNCR ON ASH GROVE

Description	Cost ($)
Total Indirect Annual Cost	[1,2] 184,063
Direct Annual Operating Cost	[2] 1,896,199
Total Annual Cost	2,080,262

[1] Includes capital recovery
[2] Ash Grove SNCR Cost.

TABLE 17—SUMMARY OF NO_X BART COSTS FOR SNCR ON ASH GROVE

Total capital investment ($)	Total annual cost ($)	Annual emissions reductions (tpy)	Average cost effectiveness ($/ton)
925,324	2,080,262	946	2,199

LNB + SNCR

We calculated the cost effectiveness of LNB + SNCR by dividing the sum of the annual cost of the two technologies described above by the emissions reduction that would be achieved. We summarize the cost information from our LNB + SNCR analysis in Tables 18 and 19.

TABLE 18—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR LNB + SNCR ON ASH GROVE

Description	Cost ($)
Total Annual Cost LNB	158,630
Total Annual Cost SNCR	2,080,262
Total Annual Cost LNB + SNCR	2,238,892

[42] CRF is 0.0944 and is based on a 7% interest rate and 20 year equipment life. Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

[43] CRF is 0.0944 and is based on a 7% interest rate and 20 year equipment life. Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

TABLE 19—SUMMARY OF NO_X BART COSTS FOR LNB + SNCR ON ASH GROVE

Total annual cost ($)	Annual emissions reductions (tpy)	Average cost effectiveness ($/ton)
2,238,892	1,088	2,058

Factor 2: Energy and Non Air Quality Impacts

LNBs are not expected to have energy impacts. SNCR systems require electricity to operate the blowers and pumps. The generation of the electricity will most likely involve fuel combustion, which will cause emissions. While the required electricity will result in emissions, these emissions should be small compared to the reduction in NO_X that would be gained by operating an SNCR system.[44] LNBs are not expected to have any non-air quality environmental impacts. Transporting the chemical reagents for SNCR would use natural resources for fuel and would have associated air quality impacts. The chemical reagents would be stored on site and could result in spills to the environment while being transferred between storage vessels or if containers were to fail during storage or movement. The environmental impacts associated with proper transportation, storage, and/or disposal should not be significant. Therefore, the non-air quality environmental impacts did not warrant eliminating LNB or SNCR.

Factor 3: Any Existing Pollution Control Technology in Use at the Source

Ash Grove currently uses good combustion practices and burner pipe maintenance/position for NO_X control.

Factor 4: Remaining Useful Life

EPA has determined that the remaining useful life of the kiln is at least 20 years. EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Factor 5: Evaluate Visibility Impacts

We conducted modeling for Ash Grove as described in section V.C.3.a. Table 20 presents the visibility impacts of the 98th percentile of daily maxima for each Class I area from 2006 through 2008.

TABLE 20—DELTA DECIVIEW IMPROVEMENT FOR NO_X CONTROLS ON ASH GROVE

Class I area	Baseline impact (delta deciview)	Improvement from LNB (delta deciview)	Improvement from SNCR (delta deciview)	Improvement from LNB + SNCR (delta deciview)
Anaconda Pintler WA	0.426	0.050	0.116	0.166
Bob Marshall WA	0.604	0.074	0.173	0.247
Gates of the Mountains WA	4.446	0.359	0.856	1.248
Glacier NP	0.193	0.021	0.050	0.069
Mission Mountains WA	0.242	0.024	0.043	0.072
North Absaroka WA	0.215	0.028	0.065	0.092
Red Rock Lakes WA	0.130	0.016	0.038	0.054
Scapegoat WA	1.022	0.131	0.308	0.441
Selway-Bitterroot WA	0.412	0.047	0.110	0.158
Teton WA	0.163	0.021	0.048	0.065
Washakie WA	0.174	0.020	0.046	0.068
Yellowstone NP	0.190	0.028	0.064	0.091

Table 21 presents the number of days with impacts greater than 0.5 deciviews for each Class area from 2006 through 2008.

TABLE 21—DAYS GREATER THAN 0.5 DECIVIEW FOR NO_X CONTROLS ON ASH GROVE

[Three year total]

Class I area	Baseline (days)	Using LNB	Using SNCR	Using LNB + SNCR
Anaconda Pintler WA	6	6	6	5
Bob Marshall WA	21	18	13	9
Gates of the Mountains WA	361	349	327	296
Glacier NP	2	1	0	0
Mission Mountains WA	8	8	6	5
North Absaroka WA	2	2	0	0
Red Rock Lakes WA	0	0	0	0
Scapegoat WA	37	35	25	18
Selway-Bitterroot WA	7	7	5	4
Teton WA	0	0	0	0
Washakie WA	2	0	0	0

[44] Ash Grove BART Analysis, pp. 5–13, 14.

TABLE 21—DAYS GREATER THAN 0.5 DECIVIEW FOR NO_X CONTROLS ON ASH GROVE—Continued

[Three year total]

Class I area	Baseline (days)	Using LNB	Using SNCR	Using LNB + SNCR
Yellowstone NP	3	1	1	1

Modeling was performed at 35% control effectiveness rather than 50% control effectiveness for SNCR and at 50% control effectiveness rather than 58% control effectiveness for LNB + SNCR. Therefore, visibility improvement from SNCR and LNB + SNCR would be greater than what is shown.

Step 5: Select BART

We propose to find that BART for NO_X is an emission limit of 8.0 lb/ton of clinker (30-day rolling average) based on the use of LNB + SNCR at Ash Grove. Of the five BART factors, cost and visibility improvement were the critical ones in our analysis of controls for this source.

In our BART analysis for NO_X at Ash Grove, we considered LNB, SNCR, and LNB + SNCR. The comparison between our LNB, SNCR, and LNB + SNCR analysis is provided in Table 22.

TABLE 22—SUMMARY OF NO_X BART ANALYSIS COMPARISON OF CONTROL OPTIONS FOR ASH GROVE

Control option	Total capital investment	Total annual cost	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts [1,2]	
					Visibility improvement (delta deciviews)	Fewer days > 0.5 deciview
LNB + SNCR	1,191,632	2,238,893	2,058	1,117	1.248	65
SNCR	925,324	2,080,262	2,199	2,903	0.856	34
LNB	266,309	158,630	559	[3]	0.359	12

[1] The visibility benefit shown is for Gates of the Mountains WA.

[2] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2006 through 2008) at the Class I area that showed the greatest improvement, Gates of the Mountains, WA. Similarly, the number of days above 0.5 deciviews is the total for the modeled 3-year meteorological period at Gates of the Mountains WA.

[3] Incremental cost is not applicable to the option that has the lowest effectiveness.

We have concluded that LNB, SNCR, and LNB + SNCR are all cost effective control technologies and that all would provide substantial visibility benefits. LNB has a cost effectiveness value of $559 per ton of NO_X emissions reduced. SNCR is more expensive than LNB, with a cost effectiveness value of $2,199 per ton of NO_X emissions reduced. While LNB + SNCR are more expensive than LNB or SNCR alone, it has a cost effectiveness value of $2,058 per ton of NO_X emissions reduced. This is well within the range of values we have considered reasonable for BART and that states have considered reasonable for BART. We have weighed costs against the anticipated visibility impacts for Ash Grove. Any of the control options would have a positive impact on visibility. As compared to LNB alone, LNB + SNCR would provide an additional visibility benefit of 0.889 deciviews and 53 fewer days above 0.5 deciviews at Gates of the Mountains WA. As compared to SNCR alone, LNB + SNCR would provide an additional visibility benefit of 0.392 deciviews and 31 fewer days above 0.5 deciviews at Gates of the Mountains WA. We consider these impacts to be substantial, especially in light of the fact that this Class I area is not projected to meet the URP. Given the incremental visibility improvement associated with LNB + SNCR, the relatively low incremental cost effectiveness between the options, and the reasonable average cost effectiveness values for LNB + SNCR, we propose that the NO_X BART emission limit for the kiln at Ash Grove should be based on what can be achieved with LNB + SNCR.

As EPA has stated previously, adopting an output-based standard avoids rewarding a source for becoming less efficient, i.e., requiring more feed to produce a unit of product. An output-based standard promotes the most efficient production process. 73 FR 34076, June 16, 2008. Thus, for example, the NSPS for NO_X and National Emission Standards for Hazardous Air Pollutants (NESHAP) for PM are normalized by ton of clinker produced. We have recognized previously that facilities are allowed to measure feed inputs and to use a site-specific feed/clinker ratio to calculate clinker production. 75 FR 54990 (September 9, 2010). For these reasons, we are proposing to establish an emission limit on a lb/ton of clinker basis.

In proposing a BART emission limit of 8.00 lb/ton clinker, we considered the emission rate currently being achieved by Ash Grove.[45] This limit also allows for a sufficient margin of compliance for a 30-day rolling average limit that would apply at all times, including startup, shutdown, and malfunction.[46] We also are proposing monitoring, recordkeeping, and reporting requirements in regulatory text at the end of this proposal.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.'' We propose a compliance deadline of five (5) years from the date our final FIP becomes effective because of the equipment installation and potential kiln combustion modifications that will be required.

[45] Ash Grove Update, March 2012 (Ash Grove lists the mean 30-day rolling average NO_X emission rate for May 26, 2006 through September 8, 2008, at 14.4 lb/ton clinker. The 99th percentile 30-day rolling average was 18.63 lb/ton clinker. Applying 58% reduction to the 99th percentile figure yields 7.82 lb/ton clinker.)

[46] As discussed in the BART Guidelines, section V (70 FR 39172, July 6, 2005), and Section 302(k) of the CAA, emissions limits such as BART are required to be met on a continuous basis.

SO_2

Step 1: Identify All Available Technologies

We identified that the following SO_2 control technologies are available: dry absorbent addition (DAA), fuel substitution, raw material substitution, lime spray drying (LSD), semi-wet scrubbing, and wet scrubbing.

In the DAA process, a dry alkaline material such as lime, calcium hydrate, limestone, or soda ash would be added to the process gas stream upstream of the particulate matter control device (PMCD) to react with the SO_2. Ash Grove estimated that they would add a 2:1 molar ratio of lime to SO_2. Solid particles of $CaSO_4$ would be produced, which would be removed from the gas stream along with excess reagent by a PMCD in the process flow. The SO_2 removal efficiency would vary depending on the point of introduction into the process according to the temperature, degree of mixing, and retention time.

Fuel substitution is a control alternative. Ash Grove currently uses a mixture of coal and petroleum coke as the primary fuels for the kiln. In 2008, Ash Grove used 50% petroleum coke, 41% coal and 1% natural gas. The sulfur content of the petroleum coke was 5.2% [47] and the sulfur content of the coal was approximately 0.8%.[48] If sulfur in fuel input to the kiln were reduced by burning a different blend of coal and coke with lower sulfur contents, a reduction in SO_2 emissions would be expected. We considered two different options for fuel switching. Option 1 would use 62% coal with 0.8% sulfur and 38% coke with 5.2% sulfur. Option 2 would use 100% coal that has a lower sulfur content (0.7%), and a higher Btu value.[49]

Raw material substitution would entail using a different source of limestone that contains a lower pyritic sulfur content.

LSD involves injecting an aqueous lime suspension in fine droplets into the flue gas. The lime reacts with SO_2 in the flue gas to create fine particles of $CaSO_3$ or $CaSO_4$. The moisture evaporates from the particles, and the particles are collected in the PMCD.

Semi-wet scrubbers are sometimes referred to as spray dryer absorbers (SDAs). This technology uses lime or limestone to react with SO_2. This technology has been used for SO_2 control on preheater/calciner kilns, but it can be successfully used on long kilns by adding spray nozzles that are made of special materials to prevent nozzle clogging. A semi-wet scrubber can achieve a SO_2 removal efficiency of 30% to 60%. Clogging may not be an issue with semi-wet scrubbers that use lime due to the small size of the lime particles (3–10 microns) which allows the particles to dissolve in water droplets quickly and react with the gaseous SO_2.

Wet scrubbing involves passing flue gas downstream from the main PMCD through a sprayed aqueous suspension of lime or limestone that is contained in a scrubbing device. The SO_2 reacts with the scrubbing reagent to form lime sludge that is collected. The sludge usually is dewatered and disposed of at an offsite landfill.

Step 2: Eliminate Technically Infeasible Options

With regard to raw material substitution, using raw materials with a lower pyritic sulfur content could reduce SO_2 emissions. Because cement plants are built at or near a source of limestone so that shipping costs are minimized, it would be infeasible, however, to obtain raw material with a lower pyritic sulfur content from some other source.

The design of a wet kiln, unlike a preheater/precalciner (PH/PC) kiln, is not amenable to the addition of a LSD. By its design, a PH/PC provides a natural location for a spray dryer type control system to be used between the top of the preheater tower and the PMCD. A wet kiln does not have that attribute. The back end of Ash Grove's wet kiln has a relatively short retention time prior to the PMCD and this would not allow for a spray dryer. For this reason, this alternative was not considered further.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

EPA estimates that the appropriate control effectiveness of DAA at Ash Grove is 30%.[50] A literature search indicates that hydrated lime appropriately injected can easily produce a 30% SO_2 control efficiency with a 2.5 to 1 CaO to SO_2 ratio.[51]

For fuel switching, we used a SO_2 control effectiveness of 17% for the purposes of considering fuel switching to 38% coke and 62% coal and SO_2 control effectiveness of 60% for the purposes of considering fuel switching to 100% low-sulfur coal.[52]

The efficiency of semi-wet scrubbing is estimated to be 90%. A 90% SO_2 control effectiveness is the minimum of the range for a semi-wet scrubber with lime absorbent medium.[53] EPA has stated that a well designed and operated wet scrubber can consistently achieve at least 90% control (75 FR 54995, Sept. 9, 2010) and that 95% control efficiency is possible on cement kilns and consistent with other information on the performance of scrubbers for SO_2 removal (73 FR 34080, June 16, 2008).[54] We used 90% control effectiveness for our analysis, which is at the lower end of the range that is possible.

TABLE 23—SUMMARY OF SO_2 BART ANALYSIS CONTROL TECHNOLOGIES FOR ASH GROVE

Control Option	Control effectiveness (%)	Annual emissions reduction (tpy)	Remaining annual emissions (tpy)
Fuel Switching Option 1 (38% coke/62% coal)	[1] 17	200	978
DAA	30	353	825
Fuel Switching Option 2 (lower sulfur coal)	[1] 60	707	471
Semi-wet scrubbing	90	1060	118
Wet scrubbing	90	1060	118
No Controls (Baseline)	0	0	[2] 1,178

[1] Ash Grove Response to Comments, Attachment A.

[47] Ash Grove Additional Response to Comments.

[48] Ash Grove BART Analysis, p. 4–2.

[49] Ash Grove Response to Comments, Attachment A.

[50] Ash Grove January 2012 Update.

[51] Formation and Techniques for Control of Sulfur Oxide and Other Sulfur Compounds in Portland Cement Kiln Systems by F.M. Miller, G.L. Young and M. von Seebach (''Formation and Techniques of Sulfur Oxide and Other Sulfur Compounds'', (PCA R&D Serial No. 2460), p. 43.

[52] Ash Grove BART Analysis, p. 4–11.

[53] Formation and Techniques of Sulfur Oxide and Other Sulfur Compounds, p. 46.

[54] Assessment of Control Technology Options for BART–Eligible Sources, March 2005.

[2] 2008 NEI.

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

DAA

We relied on Ash Grove's costs [55] for DAA with the following exceptions. We present the costs for DAA in Table 24. In our estimate, we used a CRF consistent with 20 years of useful life of the kiln and equipment.[56] EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. In order to calculate the annualized capital cost, we multiplied the capital cost by the CRF.[57] We used 1,178 tpy of SO_2 as was reported to the NEI for 2008.[58] We summarize the cost information for DAA in Tables 24, 25, and 26.

TABLE 24—SUMMARY OF SO_2 BART CAPITAL COST ANALYSIS FOR DAA ON ASH GROVE

Description	Cost ($)
Total Capital Investment	[1] 330,620
Capital Recovery	[2] 31,211

[1] Ash Grove Update January 2012.
[2] Capital Recovery was determined by multiplying the Total Capital Investment by the CRF of 0.0944, which is based on a 7% interest rate and 20 year equipment life. The justification for using the CRF of 0.0944 can be found in Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/.*

TABLE 25—SUMMARY OF EPA SO_2 BART ANNUAL COST ANALYSIS FOR DAA ON ASH GROVE

Description	Cost ($)
Total Indirect Annual Cost	[1] 205,243
Total Annual Operating Cost	[2] 257,839
Total Annual Cost	463,082

[1] Includes capital recovery.
[2] Ash Grove Update January 2012.

TABLE 26—SUMMARY OF SO_2 BART COSTS FOR DAA ON ASH GROVE

Total capital investment ($)	Total annual cost ($)	Annual emissions reductions (tpy)	Average cost effectiveness ($/ton)
330,620	463,082	323	1,434

We relied on Ash Grove's costs [59] for fuel switching with the following exception. We used 1,178 tpy of SO_2 as was reported to the NEI for 2008. There is no capital cost for fuel switching because there is no equipment to buy or install. However, annual cost will increase due to increased fuel cost. We summarize the cost information for fuel switching in Tables 27 and 28.

TABLE 27—SUMMARY OF EPA SO_2 BART ANNUAL COST ANALYSIS FOR FUEL SWITCHING FOR ASH GROVE

Description	Cost ($)
Total Annual Cost Option 1 (38% coke/62% coal)	[1] 487,877
Total Annual Cost Option 2 (lower sulfur coal)	[1] 2,908,170

[1] Ash Grove Response to Comments.

TABLE 28—SUMMARY OF SO_2 BART COSTS FOR FUEL SWITCHING ON ASH GROVE

Control option	Total annual cost ($)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
Fuel Switching Option 1	487,877	200	2,439
Fuel Switching Option 2	2,908,170	707	4,113

[55] Ash Grove Update January 2012.

[56] CRF is 0.0944 and is based on a 7% interest rate and 20 year equipment life. Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/.*

[57] Id.

[58] 2008 NEI.

[59] Ash Grove Response to Comments, Attachment A.

Semi-Wet Scrubbing

We relied on Ash Grove's costs [60] for fuel switching with the following exceptions. We present the costs for semi-wet scrubbing in Table 29. In our estimate, we used a CRF consistent with 20 years for the useful life of the kiln [61] EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

In order to calculate the annualized capital cost, we multiplied the capital cost by the CRF.[62] We used 1,178 tpy of SO_2 as was reported to the NEI for 2008. We summarize the cost information for semi-wet scrubbing in Tables 29, 30, and 31.

TABLE 29—SUMMARY OF SO_2 BART CAPITAL COST ANALYSIS FOR SEMI-WET SCRUBBING ON ASH GROVE

Description	Cost ($)
Total Capital Investment	[1] 11,644,912
Capital Recovery	[1,2] 1,099,280

[1] Ash Grove Additional Information October 2011.
[2] Capital Recovery was determined by multiplying the Total Capital Investment by the CRF of 0.0944 which is based on a 7% interest rate and 20 year equipment life. The justification for using the CRF of 0.0944 can be found in Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/.*

TABLE 30—SUMMARY OF EPA SO_2 BART ANNUAL COST ANALYSIS FOR SEMI-WET SCRUBBING ON ASH GROVE

Description	Cost ($)
Total Indirect Annual Cost	[1,2] 1,689,936
Total Annual Operating Cost	[1] 250,068
Total Annual Cost	1,940,004

[1] Ash Grove Additional Information October 2011.
[2] Includes capital recovery.

TABLE 31—SUMMARY OF SO_2 BART COSTS FOR SEMI-WET SCRUBBING ON ASH GROVE

Total capital investment ($)	Total annual cost ($)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
11,644,912	1,940,004	1,060	1,830

Wet Scrubbing

We relied on costs provided by Ash Grove for wet scrubbing, which we note appear to be more expensive than other cost estimates for wet scrubbing on cement kilns. We present the costs for wet scrubbing in Table 32. In our estimate, we used a CRF consistent with 20 years for the remaining useful life of the kiln [63] EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

In order to calculate the annualized capital cost, we multiplied the capital cost by the CRF.[64] We used 1,178 tpy of SO_2 as was reported to the NEI for 2008. We summarize the cost information for wet scrubbing in Tables 32, 33, and 34.

TABLE 32—SUMMARY OF SO_2 BART CAPITAL COST ANALYSIS FOR WET SCRUBBER ON ASH GROVE

Description	Cost ($)
Total Capital Investment	[1] 30,022,424
Capital Recovery	[1,2] 2,834,117

[1] Ash Grove Additional Information October 2011.
[2] Capital Recovery was determined by multiplying the Total Capital Investment by the CRF of 0.0944 which is based on a 7% interest rate and 20 year equipment life. The justification for using the CRF of 0.0944 can be found in Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/.*

TABLE 33—SUMMARY OF EPA SO_2 BART ANNUAL COST ANALYSIS FOR WET SCRUBBER ON ASH GROVE

Description	Cost ($)
Total Indirect Annual Cost	[1,2] 4,335,284
Total Annual Operating Cost	[2] 759,278

[60] Ash Grove Additional Information October 2011.

[61] CRF is 0.0944 and is based on a 7% interest rate and 20 year equipment life. Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/.*

[62] Id.

[63] *Id.*

[64] *Id.*

TABLE 33—SUMMARY OF EPA SO_2 BART ANNUAL COST ANALYSIS FOR WET SCRUBBER ON ASH GROVE—Continued

Description	Cost ($)
Total Annual Cost	5,094,562

[1] Includes capital recovery.
[2] Ash Grove Additional Information October 2011.

TABLE 34—SUMMARY OF SO_2 BART COSTS FOR WET SCRUBBER ON ASH GROVE

Total capital investment ($)	Total annual cost ($)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
30,022,424	5,094,562	1,060	4,806

Factor 2: Energy and Non Air Quality Impacts

We did not identify any energy or non-air quality environmental impacts associated with fuel switching at Ash Grove. Wet scrubbing and semi-wet scrubbing use additional water. Wet scrubbing would consume approximately 38 gallons per minute of water, resulting in approximately 19 million gallons per year. Semi-wet scrubbing would use 3.5 gallons per minute, for an annual usage of 1.75 million gallons per year.[65] DAA would not require additional water. This arid location receives 11.9 inches of rainfall annually.[66] Montana decreased the water rights held by Ash Grove's Montana City plant to match historical use, which resulted in withdrawal of previous water rights.[67] As a result even if Ash Grove were able to obtain water rights, there is no guarantee that Ash Grove would be able to rely on that water right, as in a dryer than normal year a more senior water rights holder could require that Ash Grove cease its water use.[68] The cost analysis for wet scrubbing and semi-wet scrubbing included the costs of obtaining water.[69]

Wet scrubbing, semi-wet scrubbing, and DAA would also generate a waste stream that would need to be transported and disposed. Transporting the waste would use natural resources for fuel and would have associated air quality impacts. The disposal of the solid waste itself would be to a landfill and could possibly result in groundwater or surface water contamination if a landfill's engineering controls were to fail. The environmental impacts associated with proper transportation and/or disposal should not be significant.

Wet scrubbing, semi-wet scrubbing and DAA require additional electricity to service pretreatment and injection equipment, pumps, compressors, and control systems. The additional energy requirements that would be involved in installation and operation of the evaluated controls are not significant enough to warrant eliminating any of the options evaluated. Note that cost of the additional energy requirements has been included in our calculations.

Factor 3: Any Existing Pollution Control Technology in Use at the Source

The kiln currently uses low sulfur coal as a component of fuel mix and inherent scrubbing for SO_2 control. The kiln inherently acts as an SO_2 scrubber, since some of the sulfur that is oxidized to SO_2 is absorbed by the alkali compounds in the raw material fed to the kiln.[70] Ash Grove currently uses a mixture of petroleum coke with a sulfur content of 5.2% and coal with a sulfur content of 0.8%.[71]

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Factor 5: Evaluate Visibility Impacts

We conducted modeling for Ash Grove as described in section V.C.3.a. Table 35 presents the visibility impacts of the 98th percentile of daily maxima for each Class I area from 2006 through 2008.

TABLE 35—DELTA DECIVIEW IMPROVEMENT FOR SO_2 CONTROLS ON ASH GROVE

Class I area	Baseline impact (delta deciview)	Improvement from fuel switching—Option 1 (delta deciview)	Improvement from DAA (delta deciview)	Improvement from fuel wwitching—Option 2 (delta deciview)	Improvement from semi-wet scrubbing (delta deciview)	Improvement from wet scrubbing (delta deciview)
Anaconda Pintler WA	0.426	0.015	0.020	0.050	0.074	0.074
Bob Marshall WA	0.604	0.016	0.023	0.056	0.083	0.083
Gates of the Mountains WA	4.446	0.033	0.049	0.119	0.180	0.180
Glacier NP	0.193	0.009	0.013	0.035	0.048	0.048
Mission Mountains WA	0.242	0.012	0.018	0.039	0.059	0.059
North Absaroka WA	0.215	0.009	0.012	0.018	0.030	0.030
Red Rock Lakes WA	0.130	0.007	0.010	0.015	0.022	0.022
Scapegoat WA	1.022	0.017	0.025	0.060	0.090	0.090
Selway-Bitterroot WA	0.412	0.014	0.020	0.049	0.074	0.074

[65] Ash Grove Additional Information October 2011, p. 14.
[66] Ash Grove Additional Information October 2011, p. 10.
[67] Ash Grove Additional Information October 2011, p. 14.
[68] Ash Grove Additional Information October 2011, p. 10.
[69] Ash Grove Additional Information October 2011, Attachments 1 and 2.
[70] Ash Grove Response to Comments.
[71] Ash Grove BART Analysis, p. 4–2.

TABLE 35—DELTA DECIVIEW IMPROVEMENT FOR SO_2 CONTROLS ON ASH GROVE—Continued

Class I area	Baseline impact (delta deciview)	Improvement from fuel switching—Option 1 (delta deciview)	Improvement from DAA (delta deciview)	Improvement from fuel wwitching—Option 2 (delta deciview)	Improvement from semi-wet scrubbing (delta deciview)	Improvement from wet scrubbing (delta deciview)
Teton WA	0.163	0.008	0.012	0.030	0.044	0.044
Washakie WA	0.174	0.006	0.009	0.021	0.033	0.033
Yellowstone NP	0.190	0.012	0.018	0.042	0.062	0.062

Table 36 presents the number of days with impacts greater than 0.5 deciviews for each Class area from 2006 through 2008.

TABLE 36—DAYS GREATER THAN 0.5 DECIVIEW FOR SO_2 CONTROLS ON ASH GROVE

[Three year total]

Class I area	Baseline days	Using fuel switching Option 1	Using fuel switching Option 2	Using DSI	Using SDA	Using wet scrubber
Anaconda Pintler WA	6	6	6	6	6	6
Bob Marshall WA	21	21	19	21	18	18
Gates of the Mountains WA	361	359	352	356	349	348
Glacier NP	2	1	1	1	1	1
Mission Mountains WA	8	8	8	8	7	7
North Absaroka WA	2	2	2	2	2	2
Red Rock Lakes WA	0	0	0	0	0	0
Scapegoat WA	37	37	34	36	33	33
Selway-Bitterroot WA	7	7	7	7	6	6
Teton WA	0	0	0	0	0	0
Washakie WA	2	2	0	1	0	0
Yellowstone NP	3	2	2	2	2	2

Modeling was performed at a 25% control effectiveness rather than at a 30% control effectiveness for DAA, and at a control effectiveness of 60% rather than 50% for fuel switching—option 2; however, this should not change the outcome of the analysis because of the relatively small visibility improvement for each of the SO_2 controls considered.

Step 5: Select BART

We propose to find that BART for SO_2 is no additional controls at Ash Grove. We are accordingly proposing a BART emission limit of 11.5 lb/ton clinker (30-day rolling average). Of the five BART factors, visibility was the critical one in our analysis of controls for this source. The low visibility improvement predicted from the use of SO_2 controls did not justify proposing additional controls on this source.

In our BART analysis for SO_2 at Ash Grove, we considered DAA, fuel switching, semi-wet scrubbing and wet scrubbing. The comparison between our DAA, fuel switching, semi-wet scrubbing and wet scrubbing analysis is provided in Table 37.

TABLE 37—SUMMARY OF EPA SO_2 BART ANALYSIS COMPARISON OF DAA, FUEL SWITCHING, SEMI-WET SCRUBBING AND WET SCRUBBING FOR ASH GROVE

Control option	Total capital investment	Total annual cost	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts [1,2]	
					Visibility improvement (delta deciviews)	Fewer days > 0.5 deciview
Wet Scrubbing	30,022,424	5,094,562	4,806	[3]	0.180	12
Semi-wet scrubbing	11,644,912	1,940,004	1,830	2,095	0.180	12
Fuel Switching—Option 2	[4]	2,908,170	4,113	4,773	0.119	9
DAA	330,620	463,082	1,434	[5]	0.049	5
Fuel Switching—Option 1	[4]	487,877	2,439	[6]	0.033	

[1] The visibility benefit shown is for Gates of the Mountains WA.
[2] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2006 through 2008) at the Class I area that showed the greatest improvement, Gates of the Mountains, WA. Similarly, the number of days above 0.5 deciviews is the total for the modeled 3-year meteorological period at Gates of the Mountains WA.
[3] Incremental Cost Effectiveness cannot be calculated because both technologies reduce the same amount of emissions.
[4] Capital cost is not required for fuel switching.
[5] Incremental cost would result in a negative number and therefore was not calculated.
[6] Incremental cost is not applicable to the option that has the lowest effectiveness.

We have concluded that DAA, fuel switching, semi-wet scrubbing, and wet scrubbing are all cost effective control technologies, but that they would not provide substantial visibility benefits. Given that the visibility improvement associated with SO_2 controls are relatively small, we propose that the SO_2 BART emission limit for the kiln at Ash Grove should be based on current emissions, while allowing for a sufficient margin of compliance for a 30-day rolling average limit that would apply at all times, including startup, shutdown, and malfunction.[72] As EPA has stated previously, adopting an output-based standard avoids rewarding a source for becoming less efficient, i.e., requiring more feed to produce a unit of product. An output-based standard promotes the most efficient production process. 73 FR 34076, June 16, 2008. The NSPS for NO_X and NESHAP for PM are normalized by ton of clinker produced. We have recognized previously that facilities are allowed to measure feed inputs and to use site-specific feed/clinker ratio to calculate clinker production. 75 FR 54990, Sept. 9, 2010.

Accordingly, we are proposing 11.5 lb/ton clinker as a BART emission limit for SO_2 at Ash Grove Cement. In proposing this limit, we considered the emission rate currently being achieved by Ash Grove Cement in lb/ton clinker.[73] We are also proposing monitoring, recordkeeping, and reporting requirements as described in our proposed regulatory text for 40 CFR 52.1395.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.'' Because we are not requiring additional controls to be installed, we propose that Ash Grove must comply with this emission limit within 180 days from the date our final FIP becomes effective. This will allow time for monitoring systems to be certified if necessary.

PM

Ash Grove currently has an electrostatic precipitator (ESP) for particulate control from the kiln. An ESP is a particle control device that uses electrical forces to move the particles out of the flowing gas stream and onto collector plates. The ESP places electrical charges on the particles, causing them to be attracted to oppositely charged metal plates located in the precipitator. The particles are removed from the plates by ''rapping'' and collected in a hopper located below the unit. The removal efficiencies for ESPs are highly variable; however, for very small particles alone, the removal efficiency is about 99%.[74]

Ash Grove Cement must meet a PM_{10} emission rate based on the process weight of the kiln. Pursuant to the regulatory requirement in Montana's EPA approved SIP (Administrative Rule of Montana (ARM) 17.8.310), permit condition A.8 in Ash Grove's Final Title V Operating Permit #OP2005–06 contains the following requirements: if the process weight rate of the kiln is less than or equal to 30 tons per hour, then the emission limit shall be calculated using $E = 4.10p^{0.67}$ where E = rate of emission in pounds per hour and p = process weight rate in tons per hour; however, if the process weight rate of the kiln is greater than 30 tons per hour, then the emission limit shall be calculated using $E = 55.0p^{0.11} - 40$, where E = rate of emission in pounds per hour and P = process weight rate in tons per hour.

Based on our modeling described in section V.C.3.a, PM contribution to the baseline visibility impairment is low. Table 38 shows the maximum baseline visibility impact from PM and percentage contribution to that impact from coarse PM and fine PM.

TABLE 38—ASH GROVE VISIBILITY IMPACT CONTRIBUTION FROM PM

Maximum baseline visibility impact (deciview)	% Contribution coarse PM	% Contribution fine PM
4.446	0.84	4.77

The PM contribution to the baseline visibility impact for Ash Grove is very small; therefore, any visibility improvement that could be achieved with improvements to the existing PM controls would be negligible.

Taking into consideration the above factors we propose a BART emission limit based on use of the current control technology at Ash Grove and the emission limits described above for PM/PM_{10} as BART. We find that the BART emission limit can be achieved through the operation of the existing ESP. Thus, as described in our BART Guidelines, a full five-factor analysis for PM/PM_{10} is not needed for Ash Grove.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.'' Since we propose a BART emission limit that represents current operations and no installation is necessary, we propose a compliance deadline of 30 days from the date our final FIP becomes effective.

ii. Holcim

Background

The Holcim (US) Inc. Trident cement plant near Three Forks, MT was determined to be subject to the BART requirements as explained in section V.C. As explained in section V.C., the document titled ''Identification of BART-Eligible Sources in the WRAP Region'' dated April 4, 2005 provides more details on the specific emission units at each facility. Our analysis focuses on the kiln as the primary source of SO_2 and NO_X emissions. We requested a five factor BART analysis for Holcim's Trident cement plant. The company submitted that analysis on July 6, 2007, with updated information on January 25, 2008, June 9, 2009, August 12, 2009, June 16, 2011, and March 2, 2012.[75] Holcim's five factor

[72] As discussed in the BART Guidelines, section V (70 FR 39172, July 6, 2005), and Section 302(k) of the CAA, emissions limits such as BART are required to be met on a continuous basis.

[73] Response to EPA request for supplemental information on emissions from the Montana City plant, March 9, 2012. Ash Grove lists the mean 30-day rolling average SO_2 emission rate for May 26, 2006 through September 8, 2008, at 7.2 lb/ton clinker. The 99th percentile 30-day rolling average was 11.02 lb/ton clinker.

[74] EPA Air Pollution Control Online Course, description at: *http://www.epa.gov/apti/course422/ce6a1.html.*

[75] BART analysis by Holcim for Trident Cement Plant, Three Forks, MT (''Holcim Initial Response'') (Jul 6, 2007); Responses to EPA comments on BART analysis for Trident Cement Plant (''Holcim 2008 Responses'') (Jan. 25, 2008); BART analysis by Holcim for low NO_X burners for Trident Cement Plant (''Holcim Additional Response, June 2009'') (Jun 9, 2009); Response to EPA letter regarding Confidential Business Information (CBI) claims on BART analysis for Trident Cement Plant (''Holcim

Continued

BART analysis is contained in the docket for this action and we have taken it into consideration in our proposed action.

NO_X

Step 1: Identify All Available Technologies

We identified the following previously described NO_X control technologies are available: LNB, MKF, FGR, SNCR, and SCR.

Step 2: Eliminate Technically Infeasible Options

We did not consider FGR and SCR further for Holcim since Holcim and Ash Grove are similar with regard to the relevant factors.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

For LNB on Holcim's kiln, it is appropriate to assume a control effectiveness of 15%.[76] For MKF, a control effectiveness of 30% is appropriate.[77] For SNCR, in evaluating the technology, a control effectiveness of 50% is appropriate, and for LNB+SNCR a control effectiveness of 58% is appropriate.[78]

As described above in the Ash Grove analysis, we consider 50% control effectiveness appropriate for SNCR at long wet kilns, such as Holcim's kiln.

Concentration of baseline NO_X emissions is one parameter affecting control effectiveness. The percentage of control effectiveness is greater when initial NO_X concentrations are greater. The reaction kinetics decrease as the concentration of reactants decreases. This is due to thermodynamic considerations that limit the reduction process at low NO_X concentrations.[79] The baseline NO_X emissions of the Holcim Trident kiln, in pounds per ton of clinker produced (lb/ton clinker) are significantly higher than those at Ash Grove's Midlothian kilns in Texas (described above in the Ash Grove analysis), indicating that SNCR on the Holcim kiln would be expected to achieve even greater control effectiveness when compared to SNCR on the Midlothian kilns. Information provided to EPA by Holcim on NO_X emissions at the Trident cement plant from 2008 through 2010 indicate that the mean 30-day rolling average emission rate was 9.7 lb/ton clinker,[80] much higher than Midlothian's pre-SNCR emission rate shown in the Ash Grove analysis above, which is between 4.5 and 4.9 lb/ton clinker.

A summary of the emissions projections for the NO_X control options is provided in Table 39.

TABLE 39—SUMMARY OF NO_X BART ANALYSIS CONTROL TECHNOLOGIES FOR HOLCIM

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
LNB + SNCR	58	645	467
SNCR	50	556	556
MKF	30	334	778
LNB	15	167	945
No Controls (Baseline)	0	0	[1] 1,112

[1] Holcim 2012 Response. (Holcim lists NO_X emissions at 998 tons for 2009, 1,175 tons for 2010, and 1164 tons for 2011. The average is 1,112 tons).

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

LNB

We relied on cost estimates supplied by Holcim for capital costs and annual costs,[81] but with two exceptions. We used a capital cost estimate of $4,385,307.[82] Also in our analysis, we used a CRF consistent with 20 years for the useful life of the kiln. EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. In order to calculate the annualized capital cost, we multiplied the capital cost by the CRF.[83]

We calculated the average cost effectiveness from the total annual cost and a 15% reduction from the baseline actual emissions of 1,112 tpy. We summarize the cost information for LNB in Tables 40, 41, and 42.

TABLE 40—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR LNB ON HOLCIM

Description	Cost ($)
Total Capital Investment	[1] 4,385,307
Capital Recovery	[2] 413,972

[1] Holcim Additional Response, June 2009 (revised by EPA to eliminate 1.5 multiplier for "retrofit installation").

Additional Response, August 2009'') (Aug. 12, 2009); Response to EPA request for NO_X and SO_2 emissions data for 2008–2010 (''Holcim 2011 Response'') (Jun. 16, 2011); Response to EPA request for emissions and clinker production for Holcim pursuant to CAA section 114(a) (''Holcim 2012 Response'') (Mar. 2, 2012).

[76] EPA provided an example of LNB on a long wet kiln with a control effectiveness of 14% in NOx Control Technologies for the Cement Industry, Final Report, September 2000, p. 61.

[77] Holcim Initial Response, p. 4–16.

[78] We analyzed only for commercial SNCR at Holcim. In its January 25, 2008 submittal to EPA, Holcim discussed (at pages 11–12) an alternative form of SNCR, which Holcim refers to as ''dust scoops'' SNCR. This version of SNCR would use a solid pelletized form of urea, which could be mechanically introduced into the existing ''dust scoops'' mechanism. In its August 12, 2009 submittal to EPA, Holcim presented cost spreadsheets which estimated substantially less cost for ''dust scoops'' SNCR than for commercial SNCR ($716,800 capital cost versus $1,312,800 capital cost). However, Holcim's 2008 submittal indicated that neither type of SNCR was being considered by Holcim on anything more than a trial basis. Therefore, EPA has chosen to use the commercial SNCR cost estimate in its analysis, rather than the ''dust scoops'' SNCR cost estimate.

[79] CCM, p. 1–10.

[80] Holcim 2012 Response.

[81] Holcim Additional Response, June 2009.

[82] Holcim applied a 1.5 multiplier to the direct installation costs, for ''retrofit installation.'' We did not.

[83] CRF is 0.0944 and is based on a 7% interest rate and 20-year equipment life. Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

[2] Capital Recovery was determined by multiplying the Total Capital Investment by the CRF of 0.0944 which is based on a 7% interest rate and 20-year equipment life. The justification for using the CRF of 0.0944 can be found in Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

TABLE 41—SUMMARY OF NO_X BART ANNUAL COST ANALYSIS FOR LNB ON HOLCIM

Description	Cost ($)
Total Indirect Annual Cost	[1] 413,972
Direct Annual Operating Cost	[2] 300,658
Total Annual Cost	714,629

[1] Includes capital recovery.
[2] Holcim Additional Response, June 2009.

The capital cost estimate of $4,385,307 includes the cost of converting from a direct to an indirect firing system to accommodate LNB, including installation of a baghouse, additional explosion prevention, pulverized coal storage, and dosing equipment.[84]

By comparison, our LNB cost analysis for Ash Grove Cement contains a capital cost estimate of $266,309 and annual cost estimate of $158,630. These figures are much lower than the estimate for Holcim because Ash Grove did not factor in the cost of any kiln modifications to convert from direct to indirect firing.

TABLE 42—SUMMARY OF NO_X BART COSTS FOR LNB ON HOLCIM

Total installed capital cost ($)	Total annual cost ($)	Annual emissions reductions (tpy)	Average cost effectiveness ($/ton)
4,385,307	714,629	167	4,279

MKF

We relied on cost estimates supplied by Holcim for annual costs.[85] No separate calculation of capital cost was presented by Holcim. Total annual cost of MKF was provided from an EPA publication,[86] for MKF conversion for a 50 tons-per-hour long wet kiln, scaled up by Holcim from 1997 dollars to 2006 dollars, using a 1.25607 Consumer Price Index (CPI) multiplier.[87] We calculated the cost effectiveness, from the total annual cost and a 30% reduction from the baseline actual emissions of 1,112 tpy. We present the costs for MKF in Table 43.

TABLE 43—SUMMARY OF NO_X BART COSTS FOR MKF ON HOLCIM

Total capital investment ($)	Total annual cost ($)	Annual emissions reductions (tpy)	Average cost effectiveness ($/ton)
Not calculated separately, but included in total annual cost	473,738	334	1,418

As explained in Holcim's BART analysis, the use of tire-derived fuel for MKF cannot be ensured within the five-year timeline required in the BART program. Holcim is not permitted by the State of Montana to use tires as a fuel source in its kiln until the State issues a final air quality permit allowing such use and any legal appeals are concluded.[88] Therefore, MKF is not considered further.

SNCR

We relied on cost estimates supplied by Holcim for capital costs and annual costs, with the exception of the CRF used.[89] For our analysis, we used a CRF consistent with 20 years for the useful life of the kiln. EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. In order to calculate the annualized capital cost, we multiplied the capital cost by the CRF.[90] We calculated the average cost effectiveness from the total annual cost and a 50% reduction from the baseline actual emissions of 1,112 tpy, yielding a 588 tpy reduction. We summarize the cost information from our SNCR analysis in Tables 44, 45, and 46.

[84] Holcim Additional Response, June 2009.
[85] Holcim Initial Response.
[86] NO_X Control Technologies for the Cement Industry: Final Report, September 19, 2000, EPA–457/R–00–002, Table 6–10.
[87] Holcim Initial Response, p. 4–23.
[88] Id., p. 4–25.
[89] Holcim Additional Response, August 2009, Appendix C.
[90] CRF is 0.0944 and is based on a 7% interest rate and 20-year equipment life. Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

TABLE 44—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR SNCR ON HOLCIM

Description	Cost ($)
Total Capital Investment	[1] 1,312,800
Capital Recovery	[2] 123,928

[1] Holcim Additional Response, August, 2009.
[2] Capital Recovery was determined by multiplying the Total Capital Investment by the CRF of 0.0944, which is based on a 7% interest rate and 20-year equipment life. The justification for using the CRF of 0.0944 can be found in Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

TABLE 45—SUMMARY OF NO_X BART ANNUAL COST ANALYSIS FOR SNCR ON HOLCIM

Description	Cost ($)
Total Indirect Annual Cost	[1] 123,928
Direct Annual Operating Cost	[2] 147,288
Total Annual Cost	271,216

[1] Includes capital recovery.
[2] Holcim Additional Response, August, 2009.

TABLE 46—SUMMARY OF NO_X BART COSTS FOR SNCR ON HOLCIM

Total capital investment ($)	Total annual cost ($)	Annual emissions reductions (tpy)	Average cost effectiveness ($/ton)
1,312,800	271,216	556	488

LNB + SNCR

We calculated the cost effectiveness of LNB + SNCR by dividing the sum of the annual cost of the two technologies described above by the 58% emissions reduction that would be achieved. We summarize the cost information from our LNB + SNCR analysis in Tables 47 and 48.

TABLE 47—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR LNB + SNCR ON HOLCIM

Description	Cost ($)
Total Annual Cost LNB	714,629
Total Annual Cost SNCR	271,216
Total Annual Cost LNB + SNCR	985,845

TABLE 48—SUMMARY OF NO_X BART COSTS FOR LNB + SNCR ON HOLCIM

Total annual cost ($)	Annual emissions reductions (tpy)	Average cost effectiveness ($/ton)
985,845	645	1,528

Factor 2: Energy and Non-Air Quality Impacts

LNBs are not expected to have any significant negative energy impacts [91] and are not expected to have any non-air quality environmental impacts. SNCR systems require electricity to operate the blowers and pumps. The generation of the electricity will most likely involve fuel combustion, which will cause emissions. While the required electricity will result in emissions, these emissions should be small compared to the reduction in NO_X that would be gained by operating an SNCR system.[92] Transporting the chemical reagents for SNCR would use natural resources for fuel and would have associated air quality impacts. The chemical reagents would be stored on site and could result in spills to the environment while being transferred between storage vessels or if containers were to fail during storage or movement. The environmental impacts associated with proper transportation, storage, and/or disposal should not be significant. Therefore, the non-air quality environmental impacts did not warrant eliminating LNB or SNCR.

Factor 3: Any Existing Pollution Control Technology in Use at the Source

Holcim currently uses proper kiln design and operation for NO_X control.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without

[91] Holcim Initial Response, p. 4–23.

[92] Holcim Initial Response, p. 5–13, 14.

commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Factor 5: Evaluate Visibility Impacts

We performed modeling as described previously.

We conducted modeling for Holcim as described in section V.C.3.a. Table 49 presents the Visibility Impacts of the 98th percentile of daily maxima for each Class I area from 2006 through 2008. Table 50 presents the number of days with impacts greater than 0.5 deciviews for each Class area from 2006 through 2008.

TABLE 49—DELTA DECIVIEW IMPROVEMENT FOR NO_X CONTROLS ON HOLCIM

Class I area	Baseline impact (delta deciview)	Improvement from LNB (delta deciview)	Improvement from SNCR (delta deciview)	Improvement from LNB + SNCR (delta deciview)
Gates of the Mountains WA	0.980	0.125	0.295	0.424
Yellowstone NP	0.411	0.051	0.120	0.171

TABLE 50—DAYS GREATER THAN 0.5 DECIVIEW FOR NO_X CONTROLS ON HOLCIM

[Three-year total]

Class I area	Baseline days	Using LNB	Using SNCR	Using LNB + SNCR
Gates of the Mountains WA	46	39	26	19
Yellowstone NP	13	7	4	3

Modeling was performed at 35% control effectiveness rather than 50% control effectiveness for SNCR and at 50% control effectiveness rather than 58% control effectiveness for LNB + SNCR. Therefore, visibility improvement from SNCR and LNB + SNCR would be greater than what is shown.

Step 5: Select BART

We propose to find that BART for NO_X is LNB + SNCR with an emission limit of 5.5 lb/ton of clinker (30-day rolling average). Of the five BART factors, cost and visibility improvement were the critical ones in our analysis of controls for this source.

In our BART analysis for NO_X at Holcim, we considered LNB, SNCR, and LNB + SNCR. The comparison between our LNB, SNCR, and LNB + SNCR analysis is provided in Table 51.

TABLE 51—SUMMARY OF NO_X BART ANALYSIS COMPARISON OF CONTROL OPTIONS FOR HOLCIM

Control option	Total capital investment	Total annual cost	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts [1,2]	
					Visibility improvement (delta deciviews)	Fewer days > 0.5 deciview
LNB + SNCR	6,271,009	985,845	1,528	8,029	0.424	27
SNCR	1,312,800	271,216	488	[3] −1,140	0.295	20
LNB	4,958,209	714,629	4,279	[4]	0.125	7

[1] The visibility benefit shown is for Gates of the Mountains WA.
[2] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2006 through 2008) at the Class I area that showed the greatest improvement, Gates of the Mountains, WA. Similarly, the number of days above 0.5 deciviews is the total for the modeled 3-year meteorological period at Gates of the Mountains WA.
[3] The incremental cost effectiveness from LNB to SNCR is a negative number because the numerator in dollars is negative (i.e., the total annual cost of SNCR is less than LNB) but the denominator in tons is positive (i.e., SNCR achieves more tons of emission reduction than LNB).
[4] Incremental cost and impact is not applicable to the option that has the lowest emission control effectiveness.

We have concluded that LNB + SNCR is a cost effective control technology and would provide substantial visibility benefits. LNB + SNCR has a cost effectiveness value of $1,528 per ton of NO_X emissions reduced. This is well within the range of values we have considered reasonable for BART and that states have considered reasonable for BART.

We have weighed costs against the anticipated visibility impacts for Holcim. Any of the control options would have a positive impact on visibility. As compared to LNB alone, LNB + SNCR would provide an additional visibility benefit of .299 deciviews and 20 fewer days above 0.5 deciviews at Gates of the Mountains WA. As compared to SNCR alone, LNB + SNCR would provide an additional visibility benefit of 0.129 deciviews and seven fewer days above 0.5 deciviews at Gates of the Mountains WA. Overall improvement from LNB + SNCR is 0.424 deciviews. We consider this impact to be beneficial, especially in light of the fact that this Class I area is not projected to meet the URP. Given the visibility improvement associated with LNB + SNCR and the reasonable average cost effectiveness for LNB + SNCR, we propose that the NO_X BART emission limit for the kiln at Holcim should be based on what can be achieved with LNB + SNCR.

As EPA has explained in earlier in this notice, adopting an output-based standard avoids rewarding a source for becoming less efficient.

In proposing a BART emission limit of 5.5 lb/ton clinker, we considered the emission rate currently being achieved by Holcim in lb/ton clinker, then applied an emission reduction of 58%.[93] This limit allows for a sufficient margin of compliance for a 30-day rolling average limit that would apply at all times, including startup, shutdown, and malfunction.[94] We also are proposing monitoring, recordkeeping, and reporting requirements in regulatory text at the end of this proposal.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.'' We propose a compliance deadline of five (5) years from the date our final FIP becomes effective because of the equipment installation and potential kiln combustion modifications that will be required.

SO_2

Step 1: Identify All Available Technologies

We identified that the following SO_2 control technologies are available: wet scrubbing, semi-wet scrubbing which for this source is the same as a SDA, fuel switching (lower sulfur fuel), and hot meal injection.

Wet scrubbing involves passing flue gas downstream from the main PMCD through a sprayed aqueous suspension of lime or limestone that is contained in a scrubbing device. The SO_2 reacts with the scrubbing reagent to form calcium sulfate ($CaSO_4$) sludge that is collected. The sludge usually is dewatered and disposed of at an offsite landfill.

SDAs use lime or limestone to react with SO_2. This technology involves injecting an aqueous lime or limestone suspension in fine droplets into the flue gas. The lime reacts with SO_2 in the flue gas to create fine particles of calcium sulfite ($CaSO_3$) or $CaSO_4$. The moisture evaporates from the particles, and the particles are collected in the PMCD. Limestone absorbent scrubbers have been used for SO_2 control on preheater/calciner kilns, but they can be successfully used on long kilns by adding spray nozzles that are made of special materials to prevent nozzle clogging. A SDA can achieve a SO_2 removal efficiency of 30% to 60%. Clogging may not be an issue with SDAs that use lime due to the small size of the lime particles (3–10 microns) which allows the particles to dissolve in water droplets quickly and react with the gaseous SO_2. One manufacturer of these scrubber systems indicates an SO_2 removal efficiency of greater than 90% for SDAs.[95]

Fuel switching is a control alternative. Holcim currently uses a mixture of about 60% low-sulfur coal and 40% petroleum coke as the primary fuels for the kiln. The sulfur content of the petroleum coke is approximately 5.3% and the sulfur content of the coal is approximately 0.8%.[96] If sulfur in fuel input to the kiln were reduced by burning a different blend of coal and coke with lower sulfur contents, a reduction in SO_2 emissions would be expected. We considered two different options for fuel switching. Option 1 would use 75% coal with 0.8% sulfur and 25% coke with 5.3% sulfur. Option 2 would use 100% coal, which has a lower sulfur content (0.8%) than coke.

Hot meal injection is the hot-meal bypass in a PH/PC kiln system, where calcined hot meal produced in the kiln is, in part, discharged in front of the kiln entrance after the precalcining process, so that the hot meal can scrub some of the SO_2 generated from the kiln feed. Achievable SO_2 reduction has been estimated at between 0% and 30%.[97]

Step 2: Eliminate Technically Infeasible Options

As explained above, hot meal is produced in a calcined/preheated kiln. Holcim does not have a PH/PC kiln design from which hot meal can be obtained. Therefore, hot meal injection was not considered further.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

EPA has stated that a well designed and operated wet scrubber can consistently achieve at least 90% control (75 FR 54995 (September 9, 2010)) and that 95% control efficiency is possible (73 FR 34080 (June 16, 2008)). Holcim's analysis used 95% control, which is the upper end of the range that is possible.[98] We used 95% control effectiveness for our analysis of wet scrubbing.

As cited above, according to one SDA manufacturer, 90% SO_2 control effectiveness is the minimum of the range for a SDA with lime absorbent medium. Given the extremely low SO_2 emissions from Holcim's kiln (about 50 tpy),[99] we consider 90% control to be optimistic here; nevertheless, relying on information from Holcim's July 6, 2007 submittal, we used 90% control effectiveness for our analysis.

For fuel substitution to 100% coal with 0.8% sulfur content, we relied on Holcim's estimate of 62% control effectiveness. For fuel substitution to 75% coal with 0.8% sulfur content and 25% petroleum coke with 5.3% sulfur content, we relied on Holcim's estimate of 32% control effectiveness.[100] We also evaluated the visibility impact from fuel switching to lower sulfur coal for which we used a control effectiveness of 60%.

TABLE 52—SUMMARY OF SO_2 BART ANALYSIS CONTROL TECHNOLOGIES FOR HOLCIM

Control option	Control effectiveness (%)	Annual emissions reduction (tpy)	Remaining annual emissions (tpy)
Wet scrubbing	95	47.7	2.5
SDA	90	45.2	5.0
Fuel Switching Option 2 (100% lower sulfur coal)	62	19.1	31.1
Fuel Switching Option 1 (25% coke/75% coal)	32	34.1	16.1
No Controls (Baseline)	0	0	50.2

[93] Holcim 2012 Response. (Holcim lists the mean 30-day rolling average NO_X emission rate for 2008–2011 at 9.7 lb/ton clinker. The 99th percentile 30-day rolling average was 12.6 lb/ton clinker. Applying 58% reduction to the 99th percentile figure yields 5.29 lb/ton clinker.)

[94] As discussed in the BART Guidelines, section V (70 FR 39172, July 6, 2005), and Section 302(k) of the CAA, emissions limits such as BART are required to be met on a continuous basis.

[95] Formation and Techniques of Sulfur Oxide and Other Sulfur Compounds, p. 46.

[96] Holcim 2008 Responses, p. 6.

[97] Formation and Techniques of Sulfur Oxide and Other Sulfur Compounds, pp. 31, 44 and 48.

[98] Holcim Initial Response, p. 4–11.

[99] Holcim 2012 Response (Holcim listed the SO_2 emissions at 53.5 tons in 2009, 64.1 tons in 2010, and 33.1 tons in 2011. The average was 50.2 tons).

[100] Holcim 2008 Responses, p. 6.

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

Wet Scrubbing

We present the costs for wet scrubbing in Table 53. We relied on cost estimates from Holcim,[101] with the exception of the CRF. We used a CRF consistent with 20 years for the remaining useful life of the kiln. EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. In order to calculate the annualized capital cost, we multiplied the capital cost by the CRF.[102] Since Holcim presented the capital costs and annual costs in 2002 dollars, then scaled up the total annual cost to 2007 dollars using a 1.1582 CPI multiplier, we present the costs in the same manner here. We calculated the average cost effectiveness from the total annual cost and a 95% reduction in the baseline actual emissions of 50.2 tpy. We summarize the cost information for wet scrubbing in Tables 53, 54, and 55.

TABLE 53—SUMMARY OF SO_2 BART CAPITAL COST ANALYSIS FOR WET SCRUBBER ON HOLCIM

Description	Cost ($)
Total Capital Investment (2002 dollars)	[1] 8,098,489
Capital Recovery (2002 dollars)	[2] 764,497

[1] Holcim Additional Response, August 2009, Appendix B.
[2] Capital Recovery was determined by multiplying the CRF of 0.0944 which is based on a 7% interest rate and 20 year equipment life. The justification for using the CRF of 0.0944 can be found in Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

TABLE 54—SUMMARY OF EPA SO_2 BART ANNUAL COST ANALYSIS FOR WET SCRUBBER ON HOLCIM

Description	Cost ($)
Total Indirect Annual Cost (2002 dollars)	[1] 764,297
Total Annual Operating Cost (2002 dollars)	[2] 3,453,408
Total Annual Cost (2002 dollars)	4,217,905
Total Annual Cost (2007 dollars)	4,885,177

[1] Includes capital recovery.
[2] Holcim Additional Response August 2009, Appendix B.

TABLE 55—SUMMARY OF SO_2 BART COSTS FOR WET SCRUBBER ON HOLCIM

Total capital investment ($)	Total annual cost ($)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
8,098,489 (2002 dollars)	4,885,177 (2007 dollars)	47.7	102,414

SDA

We present the costs for SDA in Table 56. We relied on cost estimates from Holcim,[2] with the exception that we used a CRF consistent with 20 years for the useful life of the kiln. EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. In order to calculate the annualized capital cost, we multiplied the capital cost by the CRF.[103] We calculated the average cost effectiveness from the total annual cost and a 90% reduction in the baseline actual emissions of 50.2 tpy. We summarize the cost information for SDA in Tables 56, 57, and 58.

TABLE 56—SUMMARY OF SO_2 BART CAPITAL COST ANALYSIS FOR SDA ON HOLCIM

Description	Cost ($)
Total Capital Investment	[1] 22,597,000
Capital Recovery	[2] 2,133,156

[1] Holcim Initial Response, Appendix C.
[2] Capital Recovery was determined by multiplying the CRF of 0.0944 which is based on a 7% interest rate and 20 year equipment life. The justification for using the CRF of 0.0944 can be found in Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

[101] Holcim Additional Response, August 2009, Appendix B.

[102] CRF is 0.0944 and is based on a 7% interest rate and 20 year equipment life. Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

[103] *Id.*

TABLE 57—SUMMARY OF EPA SO_2 BART ANNUAL COST ANALYSIS FOR SDA ON HOLCIM

Description	Cost ($)
Total Indirect Annual Cost	[1] 2,133,156
Total Annual Operating Cost	[2] 1,186,133
Total Annual Cost	3,319,289

[1] Includes capital recovery.
[2] Holcim Initial Response, Appendix C.

TABLE 58—SUMMARY OF SO_2 BART COSTS FOR SDA ON HOLCIM

Total capital investment ($)	Total annual cost ($)	Emissions reductions (tpy)	Average cost effective-ness ($/ton)
22,597,000	3,319,289	45.2	73.435

Fuel Switching

We relied on Holcim's costs for fuel switching.[104] We calculated the average cost effectiveness from the total annual cost and a 32% reduction in the baseline actual emissions of 50.2 tpy for option 1, or a 62% reduction for option 2. There is no capital cost for fuel switching because there is no equipment to buy or install. However, annual cost will increase due to increased fuel cost. We summarize the cost information for fuel switching in Tables 59 and 60.

TABLE 59—SUMMARY OF EPA SO_2 BART ANNUAL COST ANALYSIS FOR FUEL SWITCHING FOR HOLCIM

Description	Cost ($)
Total Annual Cost Option 1 (25% coke/75% coal)	[1] 240,515
Total Annual Cost Option 2 (100% lower sulfur coal)	[1] 659,651

[1] Holcim 2008 Response.

TABLE 60—SUMMARY OF SO_2 BART COSTS FOR FUEL SWITCHING ON HOLCIM

Control option	Total annual cost ($)	Emissions reductions (tpy)	Average cost effective-ness ($/ton)
Fuel Switching Option 1	240,515	[1] 19.1	12,592
Fuel Switching Option 2	659,651	[2] 34.1	19,344

[1] Reflects 32% reduction from 50.2 tpy baseline emissions.
[2] Reflects 62% reduction from 50.2 tpy baseline emissions.

Factor 2: Energy and Non Air Quality Impacts

Fuel Switching Does Not Have Energy or Non Air Quality Environmental Impacts

Wet scrubbing and SDA use additional water and would generate a waste stream that would need to be transported and be disposed. Transporting the waste would use natural resources for fuel and would have associated air quality impacts. The disposal of the solid waste itself would be to a landfill and could possibly result in groundwater or surface water contamination if a landfill's engineering controls were to fail. The environmental impacts associated with proper transportation and/or disposal should not be significant.

Wet scrubbing and SDAs require additional electricity to service pretreatment and injection equipment, pumps, compressors, and control systems. The additional energy requirements that would be involved in installation and operation of the evaluated controls are not significant enough to warrant eliminating any of the options evaluated. The cost of the additional energy requirements has been included in our calculations.

Factor 3: Any Existing Pollution Control Technology in Use at the Source

The kiln currently uses low sulfur coal as a component of fuel mix and inherent scrubbing for SO_2 control. The kiln inherently acts as an SO_2 scrubber, since some of the sulfur that is oxidized to SO_2 is absorbed by the alkali compounds in the raw material fed to the kiln. Holcim currently uses a mixture of petroleum coke with a sulfur content of 5.3% and coal with a sulfur content of 0.8%.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

[104] Holcim 2008 Responses, p. 6.

Factor 5: Evaluate Visibility Impacts

We conducted modeling for Holcim as described in section V.C.3.a. Table 61 presents the visibility impacts of the 98th percentile of daily maxima for each Class I area from 2006 through 2008. Table 62 presents the number of days with impacts greater than 0.5 deciviews for each Class I area from 2006 through 2008.

TABLE 61—DELTA DECIVIEW IMPROVEMENT FOR SO_2 CONTROLS ON HOLCIM

Class I area	Baseline impact (delta deciview)	Improvement from fuel switching option 1 (delta deciview)	Improvement from fuel switching option 2 (delta deciview)	Improvement from SDA (delta deciview)	Improvement from wet scrubber (delta deciview)
Gates of the Mountains WA	0.980	0.015	0.024	0.044	0.046
Yellowstone NP	0.411	0.011	0.007	0.020	0.021

TABLE 62—DAYS GREATER THAN 0.5 DECIVIEW FOR SO_2 CONTROLS ON HOLCIM

[Three-year total]

Class I area	Baseline (days)	Using fuel switching option 1	Using fuel switching option 2	Using SDA	Using wet scrubbing
Gates of the Mountains WA	46	45	44	43	43
Yellowstone NP	13	12	12	12	12

Modeling for fuel switching option #2 was performed assuming a 50% reduction rather than a 62% reduction.

Step 5: Select BART

We propose to find that BART for SO_2 is no additional controls at Holcim with an emission limit of 1.3 lb/ton clinker. Of the five BART factors, visibility was the critical one in our analysis of controls for this source. The low visibility improvement did not justify requiring additional SO_2 controls on this source.

In our BART analysis for SO_2 at Holcim, we considered wet scrubbing, SDA and fuel switching. The comparison between our wet scrubbing, SDA and fuel switching analysis is provided in Table 63.

TABLE 63—SUMMARY OF EPA SO_2 BART ANALYSIS COMPARISON OF WET SCRUBBING, SDA AND FUEL SWITCHING FOR HOLCIM

Control option	Total capital investment	Total annual cost	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts [1,2]	
					Visibility improvement (delta deciviews)	Fewer days > 0.5 deciview
Wet Scrubbing	8,098,489	4,217,905	102,414	408,462	0.046	3
SDA	22,597,000	3,319,289	73,435	239,607	0.044	3
Fuel Switching—Option 2	[3]	659,651	19,344	27,942	0.024	2
Fuel Switching—Option 1	[3]	240,515	12,592	[4]	0.015	1

[1] The visibility benefit shown is for Gates of the Mountains WA.
[2] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2006 through 2008) at the Class I area that showed the greatest improvement, Gates of the Mountains WA. Similarly, the number of days above 0.5 deciviews is the total for the modeled 3-year meteorological period at Gates of the Mountains WA.
[3] Capital cost is not required for fuel switching.
[4] Incremental cost is not applicable to the option that has the lowest effectiveness.

We have concluded that wet scrubbing, SDA and fuel switching are not cost effective control technologies and would not provide substantial visibility benefits. Given the minimal visibility improvements associated with SO_2 controls, we propose that the SO_2 BART emission limit for the kiln at Holcim should be based on current emissions, while allowing for a sufficient margin of compliance for a 30-day rolling average limit that would apply at all times, including startup, shutdown, and malfunction.[105]

As EPA has explained earlier in this notice, adopting an output-based standard avoids rewarding a source for becoming less efficient. Accordingly, we are proposing 1.3 lb/ton clinker as a BART emission limit for SO_2 at Holcim. In proposing this limit, we considered the emission rate currently being achieved by Holcim in lb/ton clinker.[106] We are also proposing monitoring, recordkeeping, and reporting requirements in regulatory text at the end of this proposal.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the

[105] As discussed in the BART Guidelines, section V (70 FR 39172, July 6, 2005), and Section 302(k) of the CAA, emissions limits such as BART are required to be met on a continuous basis.

[106] Holcim 2012 Response (Holcim lists the mean 30-day rolling average SO_2 emission rate for 2008–2011 at 0.37 lb/ton clinker. The 99th percentile 30-day rolling average was 1.20 lb/ton clinker).

implementation plan revision.'' Because we are not requiring additional controls to be installed, we propose that Holcim must comply with this emission limit within 180 days from the date our final FIP becomes effective. This will allow time for monitoring systems to be certified, if necessary.

PM

Holcim currently has an ESP that uses two fields in series for particulate control from the kiln. A description of an ESP can be found under the PM section of the BART analysis for Ash Grove. The efficiency of the ESP is greater than 99.9%.[107]

Based on our modeling described in section V.C.3.a, PM contribution to the baseline visibility impairment is low. Table 64 shows the maximum baseline visibility impact and percentage contribution to that impact from coarse PM and fine PM.

TABLE 64—HOLCIM VISIBILITY IMPACT CONTRIBUTION FROM PM

Maximum baseline visibility impact (deciview)	% Contribution coarse PM	% Contribution fine PM
0.980	5.79	12.61

The PM contribution to the baseline visibility impact for Holcim is very small; therefore, any visibility improvement that could be achieved with improvements to the existing PM controls would be negligible.

Holcim must meet the filterable PM emission standard of 0.77 lb/ton of clinker in accordance with their Final Title V Operating Permit #OP0982–02. This Title V requirement appears in Permit Condition G.3.; and was included in the permit pursuant to the regulatory requirements in Montana's EPA approved SIP (ARM 17.8.749).

Taking into consideration the above factors we propose basing the BART emission limit on what Holcim is currently meeting. The unit is exceeding a PM control efficiency of 99.9%, and therefore we are proposing that the current control technology and the emission limit of 0.77 lb/ton clinker for PM/PM_{10} as BART. We find that the BART emission limit can be achieved through the operation of the existing ESP. Thus, as described in our BART Guidelines, a full five-factor analysis for PM/PM_{10} is not needed for Holcim.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.'' Since we propose a BART emission limit that represents current operations and no installation is necessary, we propose a compliance deadline of 30 days from the date our final FIP becomes effective.

iii. Columbia Falls Aluminum Company (CFAC)

As described in section V.C., CFAC was determined to be subject to BART. As explained in that section, the document titled ''Identification of BART Eligible Sources in the WRAP Region'' dated April 4, 2005 provides more details on the specific emission units at each facility. We requested a five factor BART analysis for CFAC and the company submitted that analysis along with updated information.[108] CFAC's five factor BART analysis is contained in the docket for this action.

CFAC holds a permit to operate five Vertical Stud Soderberg potlines at the Columbia Falls plant.[109] Each potline has 120 individual cells that produce aluminum by the Hall-Heroult process. Subsequent to CFAC submitting its BART analysis, the CFAC plant closed at the end of October 2009.[110] In a February 19, 2010 report on the CFAC facility, Montana's Department of Environmental Quality (MDEQ) noted witnessing the plant's closure during a January 14, 2010 inspection.[111] The State's report also noted that CFAC's environmental manager was uncertain as to whether and when the plant would resume aluminum production. CFAC's environmental manager stated that the only operating emission units were some natural gas heaters used in conjunction with water treatment at the facility.

CFAC is currently not operating and it is unknown whether and when the Company will resume operations. As explained in the regulatory text for this proposal, if CFAC resumes operations, we will complete a BART determination after notification and revise the FIP as necessary in accordance with regional haze requirements, including the BART provisions in 40 CFR 51.308(e). CFAC will be required to install any controls that are required as soon as practicable, but in no case later than five years following date of the final action of this FIP.

iv. Colstrip

As described in section V.C., Colstrip Units 1 and 2 were determined to be subject to BART. As explained in section V.C., the document titled ''Identification of BART Eligible Sources in the WRAP Region'' dated April 4, 2005 provides more details on the specific emission units at each facility. PPL Montana's (PPL) Colstrip Power Plant (Colstrip), located in Colstrip, Montana, consists of a total of four electric utility steam generating units. Of the four units, only Units 1 and 2 are subject to BART. We previously provided in Section V.C. our reasoning for proposing that these two units are BART-eligible and why they are subject to BART. Units 1 and 2 boilers have a nominal gross capacity of 333 MW each. The boilers began commercial operation in 1975 (Unit 1) and 1976 (Unit 2) and are tangentially fired pulverized coal boilers that burn Powder River Basin (PRB) sub-bituminous coal as their exclusive fuel.

[107] Air Quality Technical Analysis Report, Review of Submittals Supporting the Holcim (US) Inc. Tires Combustion Proposal, Prepared for MDEQ, Prepared by Lorenzen Engineering, Inc., p. 13.

[108] The following information has been submitted by CFAC: Best Available Retrofit Technology (BART) Analysis, Nov. 5, 2007; Letter to Callie Videtich from Harold W. Robbins, RE: CFAC BART Analysis—Response to EPA Comments, June 19, 2008.

[109] See Montana Air Quality Operating Permit (MAQOP) #OP2655–02 (Title V).

[110] See Section V of MDEQ's CFAC Compliance Monitoring Report, p. 10.

[111] See Compliance Monitoring Report Section VII, p. 11.

Our analysis follows EPA's BART Guidelines. For Colstrip Units 1 and 2, the BART Guidelines are mandatory because the combined capacity for all four units at Colstrip is greater than 750 MW.[112]

We requested a five factor BART analysis for Colstrip Units 1 and 2 from PPL and the Company submitted that analysis in August 2007 along with updated information in June 2008 and September 2011. PPL's five factor BART analysis information is contained in the docket for this action and we have taken it into consideration in our proposed action.

(a) Colstrip Unit 1

NO_X

The Colstrip Unit 1 boiler is of tangential-fired design with low-NO_X burners and close-coupled overfire air (CCOFA). Originally, the unit operated with a NO_X emission limit of 0.7 lb/MMBtu. In 1997, EPA approved an early election plan under the acid rain program (ARP) that included a 0.45 lb/MMBtu annual NO_X limit. The early reduction limit expired in 2007 and the new annual limit of 0.40 lb/MMBtu under the ARP became effective in 2008. Normally, the unit operates with an actual annual average NO_X emission rate in the range of 0.30 to 0.35 lb/MMBtu, accomplished with low NO_X burners and CCOFA.[113]

Step 1: Identify All Available Technologies

We identified that the following NO_X control technologies are available: separated overfire air (SOFA), advanced separated overfire air (ASOFA), rotating opposed fire air (ROFA), rich reagent injection (RRI), SNCR, and SCR.

SOFA technology is similar to CCOFA but the air injection point for SOFA is separated some distance above the main burners and can result in improved NO_X removal efficiencies. SOFA in combination with LNB technology provides additional NO_X control by injecting air into the lower temperature combustion zone where NO_X is less likely to form. This allows complete combustion of the fuel while reducing both thermal and chemical NO_X formation.

ASOFA technology is similar to SOFA, but the amount of air staged is in the range of 20 to 30%, and, in some cases, can result in even further improved NO_X removal efficiencies compared to SOFA.

ROFA is a low NO_X system that is somewhat similar to the SOFA. ROFA uses more ports and a significantly bigger fan to accomplish similar results of getting air into the upper portion of the boiler. ROFA uses a rotating opposed fire air process, while the SOFA system uses both horizontal (yaw) and vertical nozzle tip controls.

RRI is similar to SNCR and achieves similar results.

In SNCR systems, a reagent such as NH_3 or urea is injected into the flue gas at a suitable temperature zone, typically in the range of 1,600 to 2,000 °F and at an appropriate ratio of reagent to NO_X.

SCR uses either NH_3 or urea in the presence of a metal based catalyst to selectively reduce NO_X emissions.

Step 2: Eliminate Technically Infeasible Options

Based on our review, all the technologies identified in Step 1 appear to be technically feasible for Colstrip Unit 1. In particular, both SCR and SNCR have been widely employed to control NO_X emissions from coal-fired power plants.[114,115,116]

However, in the BART Guidelines, EPA states that it may be appropriate to eliminate from further consideration technologies that provide similar control levels at higher cost. The guidelines say that, ''a possible outcome of the BART procedures discussed in these guidelines is the evaluation of multiple control technology alternatives which result in essentially equivalent emissions. It is not our intent to encourage evaluation of unnecessarily large numbers of control alternatives for every emissions unit. For example, if two or more control techniques result in control levels that are essentially identical, considering the uncertainties of emissions factors and other parameters pertinent to estimating performance, you may evaluate only the less costly of these options.'' 70 FR 39165 (July 6, 2005). As explained below, we have eliminated ASOFA, ROFA, and RRI from further consideration for this reason. SOFA is the least costly of these options.

Since ASOFA would likely not achieve greater emissions reductions compared to SOFA it is not considered further.

Since ROFA would achieve very similar emissions reductions compared to the SOFA system, ROFA is not considered further.

Since RRI would not achieve greater emissions reductions compared to SNCR, RRI is not considered further.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

At tangentially fired boilers firing PRB coal, SOFA in combination with CCOFA and LNB, can typically achieve emission rates below 0.15 lb/MMBtu on an annual basis.[117] However, due to certain issues unique to Colstrip Unit 1, a rate of 0.20 lb/MMBtu is more realistic. Specifically, these issues include: (1) that the furnace is sized smaller than others and therefore runs hotter than similar units, and (2) that the PRB coal used, classified as a borderline sub-bituminous B coal, is less reactive (produces more NO_X) than typical PRB coals.[118] The 0.20 lb/MMBtu rate represents a 34.9% reduction from the current baseline (2008 through 2010) rate of 0.308 lb/MMbtu.

The post-combustion control technologies, SNCR and SCR, have been evaluated in combination with combustion controls. That is, the inlet concentration to the post-combustion controls is assumed to be 0.20 lb/MMBtu. This allows the equipment and operating and maintenance costs of the post-combustion controls to be minimized based on the lower inlet NO_X concentration. Typically, SNCR reduces NO_X an additional 20 to 30% above LNB/combustion controls without excessive NH_3 slip.[119] Assuming that a minimum 25% additional emission reduction is achievable with SNCR, SOFA combined with SNCR can achieve an overall control efficiency of 51.1%. SCR can achieve performance emission rates as low as 0.04 to 0.07 lb/MMBtu

[112] Also, the BART Guidelines establish presumptive NO_X limits for coal-fired Electric Generating Units (EGUs) located at greater than 750 MW power plants that are operating without post-combustion controls. For the tangential-fired boilers burning sub-bituminous coal at Colstrip, that limit is 0.15 lb/MMBtu. 70 FR 39172 (July 6, 2005), Table 1. The guidelines provide that the five factor analysis may result in a limit that is different than the presumptive limit.

[113] Baseline emissions were determined by averaging the annual emissions from 2008 through 2010 as reported to the CAMD database available at *http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.*

[114] Institute of Clean Air Companies (ICAC) White Paper, Selective Catalytic Reduction Controls of NO_X Emissions from Fossil Fuel-Fired Electric Power Plants, May 2009, pp. 7–8.

[115] Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants Northeast States for Coordinated Air Use Management (NESCAUM), March 31, 2011, p. 16.

[116] ICAC White Paper, Selective Non-Catalytic Reduction for Controlling NO_X Emissions, February 2008, pp. 6–7.

[117] Low NO_X Firing Systems and PRB Fuel; Achieving as Low as 0.12 LB NO_X/MMBtu, Jennings, P., ICAC Forum, Feb. 2002.

[118] June 2008 PPL Addendum, p. 5–1.

[119] White Paper, SNCR for Controlling NO_X Emissions, Institute of Clean of Clean Air Companies, pp. 4 and 9, February 2008.

on an annual basis.[120] Assuming that an annual emission rate of 0.05 lb/MMBtu is achievable with SCR, SOFA combined with SCR can achieve an overall control efficiency of 83.8%. A summary of emissions projections for the control options is provided in Table 65.

TABLE 65—SUMMARY OF NO_X BART ANALYSIS CONTROL TECHNOLOGIES FOR COLSTRIP UNIT 1

Control option	Control effectiveness (%)	Annual emission rate (lb/MMBtu)	Emissions reduction (tpy)	Remaining emissions (tpy)
SOFA+SCR	83.5	0.050	425	678
SOFA+SNCR	51.1	0.150	2,097	2,006
SOFA	34.9	0.200	1,432	2,671
No Controls (Baseline) [1]	....	0.308	....	4,103

[1] Baseline emissions were determined by averaging the annual emissions from 2008 to 2010 as reported to the CAMD database available at *http://camddataandmaps.epa.gov/gdm/*.

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

We relied on a number of resources to assess the cost of compliance for the control technologies under consideration. In accordance with the BART Guidelines (70 FR 39166 (July 6, 2005)), and in order to maintain and improve consistency, in all cases we sought to align our cost methodologies with the EPA's Control Cost Manual (CCM).[121] However, to ensure that our methods also reflect the most recent cost levels seen in the marketplace, we also relied on control costs developed for the Integrated Planning Model (IPM) version 4.10.[122] These IPM control costs are based on databases of actual control project costs and account for project specifics such as coal type, boiler type, and reduction efficiency. The IPM control costs reflect the recent increase in costs in the five years proceeding 2009 that is largely attributed to international competition. Finally, our costs were also informed by cost analyses submitted by the sources, including in some cases vendor data.

Annualization of capital investments was achieved using the CRF as described in the CCM.[123] The CRF was computed using an economic lifetime of 20 years and an annual interest rate of 7%.[124] Unless otherwise noted, all costs presented in this proposal for the PPL BART units have been adjusted to 2010 dollars using the Chemical Engineering Plant Cost Index (CEPCI).[125] EPA's detailed control costs for Colstrip can be found in the docket.

SOFA

We relied on estimates submitted by PPL in 2008 for capital costs and direct annual costs for SOFA.[126] The Capital Cost is listed in Table 66. We then used the CEPCI to adjust capital costs to 2010 dollars. Annual costs were determined by summing the indirect annual cost and the direct annual cost (see Table 67).

TABLE 66—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR SOFA ON COLSTRIP UNIT 1

Description	Cost ($)
Total Capital Investment SOFA	4,507,528

TABLE 67—SUMMARY OF NO_X BART ANNUAL COST ANALYSIS FOR SOFA ON COLSTRIP UNIT 1

Description	Cost ($)
Total Indirect Annual Cost	425,511
Total Direct Annual Cost	664,884
Total Annual Cost	1,090,395

TABLE 68—SUMMARY OF NO_X BART COSTS FOR SOFA ON COLSTRIP UNIT 1

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
4.508	1.090	1,432	761

SOFA+SNCR We relied on control costs developed for the IPM for direct capital costs for SNCR.[127] We then used methods provided by the CCM for the remainder of the SOFA+SNCR analysis. Specifically, we used the methods in the CCM to calculate total capital investment, annual costs associated with operation and maintenance, to

[120] Information available at: *http://www.netl.doe.gov/technologies/coalpower/ewr/pubs/NOx%20control%20Lani%20AWMA%200905.pdf*.

[121] EPA's CCM Sixth Edition, January 2002, EPA 452/B–02–001.

[122] Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model, August 2010, EPA #430R10010.

[123] Section 1, Chapter 2, p. 2–21.

[124] Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

[125] Chemical Engineering Magazine, p. 56, August 2011. (*http://www.che.com*).

[126] Addendum to PPL Montana's Colstrip BART Report Prepared for PPL Montana, LLC; Prepared by TRC, (''Colstrip Addendum''), June 2008, Table 5.1–1.

[127] IPM, Chapter 5, Appendix 5–2B.

annualize the total capital investment using the CRF, and to sum the total annual costs.

We used a retrofit factor of ''1'' reflecting an SNCR retrofit of typical difficulty in the IPM control costs. As Colstrip Unit 1 burns sub-bituminous PRB coal having a low sulfur content of 0.91 lb/MMBtu (equating to a SO_2 rate of 1.8 lb/MMBtu),[128] it was not necessary to make allowances in the cost calculations to account for equipment modifications or additional maintenance associated with fouling due to the formation of ammonium bisulfate. These are only concerns when the SO_2 rate is above 3 lb/MMBtu.[129] Moreover, ammonium bisulfate formation can be minimized by preventing excessive NH_3 slip. Optimization of the SNCR system can commonly limit NH_3 slip to levels less than the 5 parts per million (ppm) upstream of the pre-air heater.[130] EPA's detailed cost calculations for SOFA+SNCR can be found in the docket.

We used a urea reagent cost estimate of $450 per ton taken from PPL's September 2011 submittal.[131] To estimate the average cost effectiveness (dollars per ton of emissions reductions) we divided the total annual cost by the estimated NO_X emissions reductions. We summarize the costs from our SOFA+SNCR cost analysis in Tables 69, 70, and 71.

TABLE 69—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR SOFA+SNCR ON COLSTRIP UNIT 1

Description	Cost ($)
Capital Investment SOFA	4,507,528
Capital Investment SNCR	8,873,145
Total Capital Investment SOFA+SNCR	13,380,673

TABLE 70—SUMMARY OF NO_X BART TOTAL ANNUAL COST ANALYSIS FOR SOFA+SNCR ON COLSTRIP UNIT 1

Description	Cost ($)
Total Annual Cost SOFA	1,090,395
Total Annual Cost SNCR	2,188,569
Total Annual Cost SOFA+SNCR	3,278,964

TABLE 71—SUMMARY OF NO_X BART COSTS FOR SOFA+SNCR ON COLSTRIP UNIT 1

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
13.381	3.279	2,097	1,564

SOFA+SCR

We relied on control costs developed for the IPM for direct capital costs for SCR.[132] We then used methods in the CCM for the remainder of the SOFA+SCR analysis. Specifically, we used the methods in the CCM to calculate total capital investment, annual costs associated with operation and maintenance, to annualize the total capital investment using the CRF, and to sum the total annual costs.

We used a retrofit factor of ''1'' in the IPM control costs, which reflects an SCR retrofit of typical difficulty. We used an aqueous ammonia (29%) cost of $240 per ton,[133] and a catalyst cost of $6,000 per cubic meter.[134] To estimate the average cost effectiveness (dollars per ton of emissions reductions) we divided the total annual cost by the estimated NO_X emissions reductions. We summarize the costs from our SOFA+SCR cost analysis in Tables 72, 73, and 74.

TABLE 72—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR SOFA+SCR ON COLSTRIP UNIT 1

Description	Cost ($)
Capital Investment SOFA	4,507,528
Capital Investment SCR	78,264,060
Total Capital Investment SOFA+SCR	82,771,589

TABLE 73—SUMMARY OF NO_X BART TOTAL ANNUAL COST ANALYSIS FOR SOFA+SCR ON COLSTRIP UNIT 1

Description	Cost ($)
Total Annual Cost SOFA	1,090,395

[128] Cost and Quality of Fuels for Electric Utility Plants 1999 Tables, Energy Information Administration, DOE/EIA–0191(99), June 2000, Table 24.

[129] IPM, Chapter 5, p. 5–9.

[130] ICAC, p. 8.

[131] NO_X Control Update to PPL Montana's Colstrip Generating Station BART Report Prepared for PPL Montana, LLC, by TRC, September 2011, p. 4–1.

[132] IPM, Chapter 5, Appendix 5–2A.

[133] Email communication with Fuel Tech, Inc., March 2, 2012.

[134] Cichanowicz 2010, p. 6–7.

TABLE 73—SUMMARY OF NO_X BART TOTAL ANNUAL COST ANALYSIS FOR SOFA+SCR ON COLSTRIP UNIT 1—Continued

Description	Cost ($)
Total Annual Cost SCR	9,852,395
Total Annual Cost SOFA+SCR	10,942,766

TABLE 74—SUMMARY OF NO_X BART COSTS FOR SOFA+SCR ON COLSTRIP UNIT 1

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
82.772	10.942	3,425	3,195

Factor 2: Energy Impacts

SNCR reduces the thermal efficiency of a boiler as the reduction reaction uses thermal energy from the boiler.[135] Therefore, additional coal must be burned to make up for the decreases in power generation. Using CCM calculations we determined the additional coal needed for Unit 1 equates to 77,600 MMBtu/yr. For an SCR, the new ductwork and the reactor's catalyst layers decrease the flue gas pressure. As a result, additional fan power is necessary to maintain the flue gas flow rate through the ductwork. SCR systems require additional electric power to meet fan requirements equivalent to approximately 0.3% of the plant's electric output.[136] Both SCR and SNCR require some minimal additional electricity to service pretreatment and injection equipment, pumps, compressors, and control systems. The additional energy requirements that would be involved in installation and operation of the evaluated controls are not significant enough to warrant eliminating any of the options evaluated. Note that cost of the additional energy requirements has been included in our calculations.

Factor 3: Non-Air Quality Environmental Impacts

SNCR and SCR will increase the quantity of ash that will need to be disposed. Transporting this waste stream for disposal would use natural resources for fuel and would have associated air quality impacts. The disposal of the solid waste itself would be to a landfill and could possibly result in groundwater or surface water contamination if a landfill's engineering controls were to fail. Transporting the chemical reagents and catalysts would use natural resources for fuel and would have associated air quality impacts. The chemical reagents would be stored on site and could result in spills to the environment while being transferred between storage vessels or if containers were to fail during storage or movement. The environmental impacts associated with proper transportation, storage, and/or disposal should not be significant. Therefore, the non-air quality environmental impacts do not warrant eliminating either SNCR or SCR.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. Thus, this factor does not impact our BART determination because the annualized cost was calculated over a 20 year period in accordance with the BART Guidelines.

Factor 5: Evaluate visibility impacts

We conducted modeling for Colstrip Unit 1 as described in section V.C.3.a. Table 75 presents the visibility impacts of the 98th percentile of daily maxima for each Class I area from 2006 through 2008. Table 76 presents the number of days with impacts greater than 0.5 deciviews for each Class I area from 2006 through 2008.

TABLE 75—DELTA DECIVIEW IMPROVEMENT FOR NO_X CONTROLS ON COLSTRIP UNIT 1

Class I area	Baseline impact (delta deciview)	Improvement from SOFA+SCR (delta deciview)	Improvement from SOFA+SNCR (delta deciview)	Improvement from SOFA (delta deciview)
North Absaroka WA	0.414	0.181	0.089	0.047
Theodore Roosevelt NP	0.922	0.404	0.264	0.182
UL Bend WA	0.895	0.378	0.249	0.164
Washakie WA	0.410	0.121	0.077	0.052
Yellowstone NP	0.275	0.081	0.059	0.034

TABLE 76—DAYS GREATER THAN 0.5 DECIVIEW FOR NO_X CONTROLS ON COLSTRIP UNIT 1

[Three year total]

Class I area	Baseline (days)	Using SOFA+SCR	Using SOFA+SNCR	Using SOFA
North Absaroka WA	7	5	5	7

[135] CCM, Section 4.2, Chapter 1, p. 1–21.

[136] *Id.*, Section 4.2, Chapter 2, p. 2–28.

TABLE 76—DAYS GREATER THAN 0.5 DECIVIEW FOR NO_X CONTROLS ON COLSTRIP UNIT 1—Continued

[Three year total]

Class I area	Baseline (days)	Using SOFA+SCR	Using SOFA+SNCR	Using SOFA
Theodore Roosevelt NP	52	17	27	33
UL Bend WA	68	29	47	52
Washakie WA	12	5	9	10
Yellowstone NP	4	2	2	2

Step 5: Select BART

We propose to find that BART for NO_X is SOFA+SNCR at Colstrip Unit 1 with an emission limit of 0.15 lb/MMBtu (30-day rolling average). Of the five BART factors, cost and visibility improvement were the critical ones in our analysis of controls for this source.

In our BART analysis for NO_X at Colstrip Unit 1, we considered SOFA, SOFA+SNCR, and SOFA+SCR. The comparison between our SOFA, SOFA+SNCR, and SOFA+SCR analysis is provided in Table 77.

TABLE 77—SUMMARY OF NO_X BART ANALYSIS COMPARISON OF CONTROL OPTIONS FOR COLSTRIP UNIT 1

Control option	Total capital investment (MM$)	Total annual cost (MM$)	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts [1]	
					Visibility improvement (delta deciviews)	Fewer days >0.5 deciview
SOFA+SCR	82.772	10.942	3,195	5,770	0.404 TRNP 0.378 UL Bend	35 TRNP. 39 UL Bend.
SOFA+SNCR	13.380	3.279	1,564	3,291	0.264 TRNP 0.249 UL Bend	25 TRNP. 21 UL Bend.
SOFA	4.508	1.090	761	[2]	0.182 TRNP 0.164 UL Bend	19 TRNP. 16 UL Bend.

TRNP—Theodore Roosevelt National Park.
UL Bend—UL Bend Wilderness Area.
[1] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2006 through 2008) at the Class I areas in the table.
[2] Incremental cost is not applicable to the option that has the lowest effectiveness.

We have concluded that SOFA, SOFA+SNCR, and SOFA+SCR are all cost effective control technologies. SOFA has a cost effectiveness value of $761 per ton of NO_X emissions reduced. SOFA+SNCR is more expensive than SOFA, with a cost effectiveness value of $1,564 per ton of NO_X emissions reduced. SOFA+SCR is more expensive than SOFA or SOFA+SNCR, having a cost effectiveness value of $3,195 per ton of NO_X emissions reduced. This is well within the range of values we have considered reasonable for BART and that states have considered reasonable for BART.

We have weighed costs against the anticipated visibility impacts for Colstrip Unit 1. Any of the control options would have a positive impact on visibility; however, the cost of SOFA+SCR ($3,195/ton) is not justified by the visibility improvement of 0.404 deciviews at TRNP and 0.378 deciviews at UL Bend. The lower cost of SOFA+SNCR ($1,564/ton) is justified when the visibility improvement is considered. SOFA+SNCR would have a visibility improvement of 0.264 deciviews at Theodore Roosevelt NP and 0.249 deciviews at UL Bend WA and it would result in 25 fewer days above 0.5 deciviews at Theodore Roosevelt-NP and 21 fewer days above 0.5 deciviews at UL Bend WA. In addition, application of SOFA+SNCR at both Colstrip Units 1 and 2 would have a combined modeled visibility improvement of 0.501 deciviews at Theodore Roosevelt NP and 0.451 deciviews at UL Bend WA. We consider these improvements to be substantial, especially in light of the fact that Theodore Roosevelt NP and UL Bend WA are not projected to meet the URP. We propose that the NO_X BART emission limit for Colstrip Unit 1 should be based on what can be achieved with SOFA+SNCR.

The proposed BART emission limit of 0.15 lb/MMBtu allows for a sufficient margin of compliance for a 30-day rolling average limit that would apply at all times, including startup, shutdown, and malfunction.[137] We are also proposing monitoring, recordkeeping, and reporting requirements as described in our proposed regulatory text for 40 CFR 52.1395.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.'' We propose a compliance deadline of five (5) years from the date our final FIP becomes effective because of the equipment installation and potential combustion modifications that will be required.

SO_2

Colstrip Unit 1 is already controlled by wet venturi scrubbers for simultaneous particulate and SO_2 control. The venturi scrubbers utilize the alkalinity of the fly ash to achieve an estimated SO_2 removal efficiency of 75%.[138] Based on emissions data from the EPA Clean Air Markets Division (CAMD), for the baseline period 2008 through 2010, the average SO_2 emission rate was 0.418 lb/MMBtu and the

[137] As discussed in the BART Guidelines, section V (70 FR 39172, July 6, 2005), and Section 302(k) of the CAA, emissions limits such as BART are required to be met on a continuous basis.

[138] BART Assessment Colstrip Generating Station, prepared for PPL Montana, LLC, by TRC (''Colstrip Initial Response''), August 2007, p. ES–3.

average SO_2 emissions were 5,548 tpy.[139]

Step 1: Identify All Available Technologies

The Colstrip Unit 1 venturi scrubber currently achieves greater than 50% removal of SO_2. For units with preexisting post-combustion SO_2 controls achieving removal efficiencies of at least 50%, the BART Guidelines state that upgrades to the system designed to improve the system's overall removal efficiency should be considered. 70 FR 39171 (July 6, 2005). For wet scrubbers, the BART Guidelines recommend that the following upgrades be considered: (a) Elimination of bypass reheat; (b) installation of liquid distribution rings; (c) installation of perforated trays; (d) use of organic acid additives; (e) improve or upgrade scrubber auxiliary equipment; and (f) redesign spray header or nozzle configuration.

In addition to the upgrades recommended by the BART Guidelines, two other upgrades are available: lime injection and lime injection with an additional scrubber vessel. Some of the upgrades recommended by the BART Guidelines are inherent in lime injection; consequently, they are available technologies only within that context. Specifically, these include options (b), (e), and (f) as listed above.

A venturi scrubber works by increasing the contact between the pollutant-bearing gas stream and the scrubbing liquid. This is achieved in the throat of the venturi scrubber where the gas stream is accelerated, thereby atomizing the scrubber liquid and promoting greater gas-liquid contact.[140] Absorption of SO_2 is further enhanced by use of alkaline reagents. Currently, the venturi scrubbers for Colstrip Unit 1 rely on the alkalinity of the coal ash to reduce SO_2. Adding lime to the water stream for these scrubbers will increase SO_2 removal. However, as the amount of lime is increased, scaling of piping and equipment is also expected to increase and this scaling will have to be removed. The scrubber vessel would not be operational during the descaling process, resulting in downtime. Greater removal efficiencies could be achieved if an additional scrubber vessel is added to the system to reduce downtime for descaling. Therefore, addition of a spare scrubber vessel is an upgrade that can improve the overall SO_2 removal efficiency of the scrubber system by increasing the system's reliability and decreasing its downtime. The additional scrubber vessel is an example of equipment redundancy that will enhance the overall system performance.

Step 2: Eliminate Technically Infeasible Options

Elimination of bypass reheat is not feasible option because Colstrip Unit 1 is designed so that there is no bypass of flue gas. Installation of perforated trays is not a feasible option because the existing scrubber design already includes this technology in the form of wash trays. Finally, the use of organic acid additives is not a feasible option because the reactivity of the lime would neutralize the acids, making the additives ineffective.

Lime injection or lime injection with an additional scrubber vessel are technically feasible control options because lime injection is currently used to control SO_2 emissions at Colstrip Units 3 and 4.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

An annual emission rate of 0.015 lb/MMBtu can be achieved with lime injection without an additional scrubber vessel. PPL stated that this is the lowest emission rate that could be achieved without adding an additional scrubber vessel.[141] An annual emission rate of 0.08 to 0.09 lb/MMBtu can be achieved with lime injection with an additional scrubber vessel. This is the emission rate that is being achieved at Colstrip Units 3 and 4 according to emissions data from CAMD.[142] The control effectiveness of each of the control options was calculated using the controlled emission rates that were provided by PPL.

A summary of control efficiencies, emission rates, and resulting emissions and emission reductions, is provided in Table 78. EPA's detailed emissions calculations can be found in the docket.

TABLE 78—SUMMARY OF BART ANALYSIS CONTROL TECHNOLOGIES FOR SO_2 FOR COLSTRIP UNIT 1

Control option	Control effectiveness (%) [1]	Annual emission rate (lb/MMBtu) [2]	Emissions reduction (tpy)	Remaining emissions (tpy)
Lime Injection with Additional Scrubber Vessel	80.9	0.080	4,486	1,062
Lime Injection	64.1	0.150	3,557	1,991
Existing Controls (Baseline) [3]	....	0.418	....	5,548

[1] Control efficiency is provided relative to the emission rate with current controls.
[2] Emission rates are provided on an annual basis.
[3] Baseline emissions for 2008 through 2010 from Clean Air Markets—Data and Maps: *http://camddataandmaps.epa.gov/gdm/*.

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

We relied on capital costs and direct annual costs provided by PPL when determining the cost of compliance for both lime injection and lime injection with an additional scrubber vessel.[143,144] All costs presented here for the Colstrip Unit 1 SO_2 control options are in year 2007 dollars. EPA's cost calculations can be found in the docket.

Lime Injection

We summarize our cost analysis for lime injection in Tables 79, 80, and 81.

[139] Clean Air Markets—Data and Maps: *http://camddataandmaps.epa.gov/gdm/*.

[140] EPA Air Pollution Control Technology Fact Sheet: Venturi Scrubber, EPA–452/F–03–017.

[141] Colstrip Addendum, p. 4–1.

[142] Clean Air Markets—Data and Maps: *http://camddataandmaps.epa.gov/gdm/*.

[143] Colstrip Initial Response, Table A4–6(c).

[144] Colstrip Addendum, Table 4.1–4.

TABLE 79—SUMMARY OF SO_2 CAPITAL COST ANALYSIS FOR LIME INJECTION ON COLSTRIP UNIT 1

Description	Cost ($)
Total Capital Investment	3,000,000

TABLE 80—SUMMARY OF SO_2 BART ANNUAL COST ANALYSIS FOR LIME INJECTION ON COLSTRIP UNIT 1

Description	Cost ($)
Total Direct Annual Cost	1,600,000
Indirect Annual Cost	283,200
Total Annual Cost	1,883,200

TABLE 81—SUMMARY OF SO_2 BART COSTS FOR LIME INJECTION ON COLSTRIP UNIT 1

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
3.000	1.883	3,557	$529

Lime Injection With an Additional Scrubber Vessel

We summarize our cost analysis for lime injection with an additional scrubber vessel cost analysis in Tables 82, 83, and 84.

TABLE 82—SUMMARY OF SO_2 CAPITAL COST ANALYSIS FOR LIME INJECTION WITH AN ADDITIONAL SCRUBBER VESSEL ON COLSTRIP UNIT 1

Description	Cost ($)
Total Capital Investment, Lime Injection	3,000,000
Capital Investment, Scrubber Vessel	25,000,000
Total Capital Investment	28,000,000

TABLE 83—SUMMARY OF SO_2 BART ANNUAL COST ANALYSIS FOR LIME INJECTION WITH AN ADDITIONAL SCRUBBER VESSEL ON COLSTRIP UNIT 1

Description	Cost ($)
Total Direct Annual Cost	1,450,000
Indirect Annual Cost	2,643,200
Total Annual Cost	4,093,200

TABLE 84—SUMMARY OF SO_2 BART COSTS ANALYSIS FOR LIME INJECTION WITH AN ADDITIONAL SCRUBBER VESSEL ON COLSTRIP UNIT 1

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
$28.000	$4.100	4,486	912

Factor 2: Energy Impacts

According to PPL, the pressure drop of the venturi scrubbers is maintained in the range of 17 to 20 inches of water column. The injection of lime will be accompanied by little to no increase in pressure drop, but it will require a small increase in pump power consumption. This is included in the cost analysis in the additional operations and maintenance expenses of $125,000 per year.[145] The additional energy requirements are not significant enough to warrant eliminating either lime injection or lime injection with an additional scrubber vessel.

[145] Colstrip Initial Response, p. 4–16.

Factor 3: Non-Air Quality Environmental Impacts

Adding lime to the scrubbers will require more frequent descaling operations that would increase the quantity of solid waste from descaling operations. Transporting this waste stream for disposal would use natural resources for fuel and would have associated air quality impacts. The disposal of the solid waste itself would be to a landfill and could possibly result in groundwater or surface water contamination if a landfill's engineering controls were to fail. EPA's analysis indicates that the environmental impacts associated with the proper transport and land disposal of the solid waste should not be significant. Therefore, the non-air quality environmental impacts do not warrant eliminating either lime injection addition or lime injection addition with an additional scrubber vessel.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. Because the remaining useful life of the source is equal to that assumed for amortization of control option capital investments, this factor does not impact our BART determination.

Factor 5: Evaluate Visibility Impacts

We conducted modeling for Colstrip Unit 1 as described in section V.C.3.a. Table 85 presents the visibility impacts of the 98th percentile of daily maxima for each Class I area from 2006 through 2008. Table 86 presents the number of days with impacts greater than 0.5 deciviews for each Class area from 2006 through 2008.

TABLE 85—DELTA DECIVIEW IMPROVEMENT FOR SO_2 CONTROLS ON COLSTRIP UNIT 1

Class I area	Baseline impact (delta deciview)	Improvement from lime injection + additional scrubber vessel (delta deciview)	Improvement from lime injection (delta deciview)
North Absaroka WA	0.414	0.164	0.146
Theodore Roosevelt NP	0.922	0.350	0.284
UL Bend WA	0.895	0.261	0.234
Washakie WA	0.410	0.154	0.145
Yellowstone NP	0.275	0.115	0.090

TABLE 86—DAYS GREATER THAN 0.5 DECIVIEW FOR SO_2 CONTROLS ON COLSTRIP UNIT 1

[Three-year total]

Class I area	Baseline (days)	Using lime injection + additional scrubber vessel	Using lime injection
North Absaroka WA	7	7	7
Theodore Roosevelt NP	52	29	33
UL Bend WA	68	31	41
Washakie WA	12	6	7
Yellowstone NP	4	2	2

Step 5: Select BART

We propose to find that BART for SO_2 is lime injection with an additional scrubber vessel at Colstrip Unit 1 with an emission limit of 0.08 lb/MMBtu (30-day rolling average). Of the five BART factors, cost and visibility improvement were the critical ones in our analysis of controls for this source.

In our BART analysis for SO_2 at Colstrip Unit 1, we considered lime injection and lime injection with an additional scrubber vessel. The comparison between our lime injection and lime injection with an additional scrubber vessel analysis is provided in Table 87.

TABLE 87—SUMMARY OF EPA SO_2 BART ANALYSIS COMPARISON OF LIME INJECTION AND LIME INJECTION WITH AN ADDITIONAL SCRUBBER VESSEL FOR COLSTRIP UNIT 1

Control option	Total capital investment (MM$)	Total annual cost (MM$)	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts [1]	
					Visibility improvement (delta deciviews)	Fewer days >0.5 deciview
Lime Injection with Additional Scrubber Vessel.	28.000	4.100	912	1,957	0.350 TRNP ...... 0.261 UL Bend	23 TRNP. 37 UL Bend.
Lime Injection	3.000	1.883	529	[2]	0.283 TRNP ...... 0.234 UL Bend	19 TRNP. 27 UL Bend.

TRNP—Theodore Roosevelt National Park.
UL Bend—UL Bend Wilderness Area.
[1] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2006 through 2008) at the Class I areas in the table.
[2] Incremental cost is not applicable to the option that has the lowest effectiveness.

We have concluded that lime injection and lime injection with an additional scrubber vessel are both cost effective control technologies. Lime injection has a cost effectiveness value of $539 per ton of SO_2 emissions reduced. Lime injection with an additional scrubber vessel is more expensive than lime injection, with a cost effectiveness value of $912 per ton of SO_2 emissions reduced. Both of these costs are well within the range of values we have considered reasonable for BART and that states have considered reasonable for BART.

We have weighed costs against the anticipated visibility impacts for Colstrip Unit 1. Either of the control options would have a positive impact on visibility. We have concluded that the cost of lime injection with an additional scrubber vessel ($912/ton) is justified by the visibility improvement of 0.350 deciviews at Theodore Roosevelt NP and 0.261 deciviews at UL Bend WA and it would result in 23 fewer days above 0.5 deciviews at Theodore Roosevelt NP and 37 fewer days above 0.5 deciviews at UL Bend WA. In addition, the application of lime injection with an additional scrubber vessel on both Colstrip Units 1 and 2 would result in a combined modeled visibility improvement of 0.592 deciviews at Theodore Roosevelt NP and 0.384 deciviews at UL Bend WA. We consider these improvements to be substantial, especially in light of the fact that Theodore Roosevelt NP and UL Bend WA are not projected to meet the URP. We propose that the SO_2 BART emission limit for Colstrip Unit 1 should be based on what can be achieved with lime injection with an additional scrubber vessel.

The proposed BART emission limit of 0.08 lb/MMBtu allows for a sufficient margin of compliance for a 30-day rolling average limit that would apply at all times, including startup, shutdown, and malfunction.[146] We are also proposing monitoring, recordkeeping, and reporting requirements as described in our proposed regulatory text for 40 CFR 52.1395.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.'' We propose a compliance deadline of five (5) years from the date our final FIP becomes effective because of the equipment installation that will be required.

PM

Colstrip Unit 1 currently has wet venturi scrubbers designed to control PM emissions. Venturi scrubbers use a liquid stream to remove solid particles. In the venturi scrubber, gas laden with PM passes through a short tube with flared ends and a constricted middle. This constriction causes the gas stream to speed up when the pressure is increased. A water spray is directed into the gas stream either prior to or at the constriction in the tube. The difference in velocity and pressure resulting from the constriction causes the particles and water to mix and combine. The reduced velocity at the expanded section of the throat allows the droplets of water containing the particles to drop out of the gas stream. Venturi scrubbers are effective in removing small particles, with removal efficiencies of up to 99%.[147] The venturi scrubbers at Unit 1 are designed to have at least 98% control efficiency and have shown control efficiencies approximating 99.5%.[148] The present filterable particulate emission rate is 0.047 lb/MMBtu.[149]

Based on our modeling described in V.C.3.a., PM contribution to the baseline visibility impairment is low. Table 88 shows the maximum baseline visibility impact and percentage contribution to that impact from coarse PM and fine PM.

TABLE 88—COLSTRIP UNIT 1 VISIBILITY IMPACT CONTRIBUTION FROM PM

Maximum baseline visibility impact (deciview)	% Contribution coarse PM	% Contribution fine PM
0.922	0.73	3.01

The PM contribution to the baseline visibility impact for Colstrip Unit 1 is very small; therefore, any visibility improvement that could be achieved with improvements to the existing PM controls would be negligible.

Colstrip Unit 1 must meet the filterable PM emission standard of 0.1 lb/MMBtu in accordance with their Final Title V Operating Permit #OP0513–06. This requirement appears in Permit Condition B.2.; and was included in the permit pursuant to ARM 17.8.340 and 40 CFR part 60, subpart D.

Taking into consideration the above factors we propose basing the BART emission limit on what Colstrip Unit 1 is currently meeting. The units are exceeding a PM control efficiency of 99%, and therefore we are proposing that the current control technology and the emission limit of 0.1lb/MMBtu for PM/PM_{10} as BART. We find that the BART emission limit can be achieved through the operation of the existing venturi scrubbers. Thus, as described in our BART Guidelines, a full five-factor analysis for PM/PM_{10} is not needed for Colstrip Unit 1.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.'' Since we propose a BART emission limit that represents current operations and no installation is necessary, we propose a compliance deadline of 30 days from the date our final FIP becomes effective.

(b) Colstrip Unit 2

NO_X

The Colstrip Unit 2 boiler is of tangential-fired design with LNB and OFA. Originally, the unit operated with a NO_X emission limit of 0.7 lb/MMBtu. In 1997, EPA approved an early election plan under the ARP that included a 0.45 lb/MMBtu annual NO_X limit. The early reduction limit expired in 2007 and the new annual limit under the ARP (0.40 lb/MMBtu) became effective in 2008. Normally, the unit operates with an actual annual average NO_X emission rate in the range of 0.30 to 0.35 lb/MMBtu, accomplished with the low NO_X burners and CCOFA.[150]

Step 1: Identify All Available Technologies

We identified that the same NO_X control technologies for Colstrip Unit 2

[146] As discussed in the BART Guidelines, section V (70 FR 39172, July 6, 2005), and Section 302(k) of the CAA, emissions limits such as BART are required to be met on a continuous basis.

[147] EPA Air Pollution Control Online Course, description at: *http://www.epa.gov/apti/course422/ce6a3.html.*

[148] Colstrip Addendum, p. 6–1

[149] Colstrip Initial Response, p. 4–8.

[150] Baseline emissions were determined by averaging the annual emissions from 2008 to 2010 as reported to the CAMD database available at *http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.*

as for Colstrip Unit 1; see Step 1 above under Colstrip Unit 1 for a list of proposed controls.

Step 2: Eliminate Technically Infeasible Options

Our analysis for Colstrip Unit 1 explains our reasoning for eliminating some of the technologies that were identified in Step 1. We have retained SOFA, SOFA+SNCR, and SOFA+SCR for evaluation.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

At tangentially fired boilers firing PRB coal, SOFA in combination with CCOFA and LNB, can typically achieve emission rates below 0.15 lb/MMBtu on an annual basis.[151] However, due to certain issues unique to Colstrip Unit 2, a rate of 0.20 lb/MMBtu is more realistic. Specifically, these issues include: (1) That the furnace was sized too small and therefore runs hotter than similar units, and (2) that the PRB coal, classified as a borderline sub-bituminous B coal, is less reactive (produces more NO_X) than typical PRB coals.[152] The 0.20 lb/MMBtu rate represents a 35.3% reduction from the current baseline (2008 through 2010) rate of 0.309 lb/MMbtu.

The post-combustion control technologies, SNCR and SCR, have been evaluated in combination with combustion controls. That is, the inlet concentration to the post-combustion controls is assumed to be 0.20 lb/MMBtu. This allows the equipment and operating and maintenance costs of the post-combustion controls to be minimized based on the lower inlet NO_X concentration. Typically, SNCR reduces NO_X an additional 20 to 30% above LNB/combustion controls without excessive NH_3 slip.[153] Assuming that a minimum 25% additional emission reduction is achievable with SNCR, SOFA combined with SNCR can achieve an overall control efficiency of 51.4%. SCR can achieve performance emission rates as low as 0.04–0.07 lb/MMBtu on an annual basis.[154] Assuming that an annual emission rate of 0.05 lb/MMBtu is achievable with SCR, SOFA combined with SCR can achieve an overall control efficiency of 83.8%. A summary of emissions projections for the control options is provided in Table 89.

TABLE 89—SUMMARY OF NO_X BART ANALYSIS CONTROL TECHNOLOGIES FOR COLSTRIP UNIT 2

Control option	Control effectiveness (%)	Annual emission rate (lb/MMBtu)	Emissions reduction (tpy)	Remaining emissions (tpy)
SOFA+SCR	83.8	0.050	3,376	652
SOFA+SNCR	51.4	0.150	2,072	1,956
SOFA	35.3	0.200	1,420	2,608
No Controls (Baseline) [1]	0	0.309		4,028

[1] Baseline emissions were determined by averaging the annual emissions from 2008 to 2010 as reported to the CAMD database available at *http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.* A summary of this information can be found in our docket.

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

Refer to the Colstrip Unit 1 section above for general information on how we evaluated the cost of compliance for NO_X controls.

SOFA

We relied on estimates submitted by PPL in 2008 for capital costs and direct annual costs for SOFA.[155] We then used the CEPCI to adjust capital costs to 2010 dollars (see Table 90). Annual costs were determined by summing the indirect annual cost and the direct annual cost (see Table 91).

TABLE 90—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR SOFA ON COLSTRIP UNIT 2

Description	Cost ($)
Total Capital Investment SOFA	4,507,528

TABLE 91—SUMMARY OF NO_X BART ANNUAL COST ANALYSIS FOR SOFA ON COLSTRIP UNIT 2

Description	Cost ($)
Total Indirect Annual Cost	425,511
Total Direct Annual Cost	664,884
Total Annual Cost	1,090,395

TABLE 92—SUMMARY OF NO_X BART COSTS FOR SOFA ON COLSTRIP UNIT 2

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
4.508	1.090	1,420	768

[151] *Low NO_X Firing Systems and PRB Fuel; Achieving as Low as 0.12 LB NO_X/MMBtu,* Jennings, P., ICAC Forum, Feb. 2002.

[152] Colstrip Addendum, p. 5–1.

[153] White Paper, SNCR for Controlling NO_X Emissions, Institute of Clean Air Companies, pp. 4 and 9, February 2008.

[154] *http://www.netl.doe.gov/technologies/coalpower/ewr/pubs/NOx%20control%20Lani%20AWMA%200905.pdf.*

[155] Colstrip Addendum, Table 5.1–1.

SOFA+SNCR

We relied on control costs developed for the IPM for direct capital costs for SNCR.[156] We then used methods provided by the CCM for the remainder of the SOFA+SNCR analysis. Specifically, we used the methods in the CCM to calculate total capital investment, annual costs associated with operation and maintenance, to annualize the total capital investment using the CRF, and to sum the total annual costs.

We used a retrofit factor of ''1'' reflecting an SNCR retrofit of typical difficulty in the IPM control costs. Colstrip Unit 2 burns sub-bituminous PRB coal having a low sulfur content of 0.91 lb/MMBtu (equating to a SO_2 rate of 1.8 lb/MMBtu).[157] As explained in our analysis for Colstrip Unit 1, it was not necessary to make allowances in the cost calculations to account for equipment modifications or additional maintenance associated with fouling due to the formation of ammonium bisulfate. EPA's detailed cost calculations for SOFA+SNCR can be found in the docket.

We used a urea reagent cost estimate of $450 per ton taken from PPL's September 2011 submittal.[158] To estimate the average cost effectiveness (dollars per ton of emissions reductions) we divided the total annual cost by the estimated NO_X emissions reductions. We summarize the costs from our SOFA+SNCR cost analysis in Tables 93, 94, and 95.

TABLE 93—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR SOFA+SNCR ON COLSTRIP UNIT 2

Description	Cost ($)
Capital Investment SOFA	4,507,528
Capital Investment SNCR	8,873,145
Total Capital Investment SOFA+SNCR	13,380,673

TABLE 94—SUMMARY OF NO_X BART TOTAL ANNUAL COST ANALYSIS FOR SOFA+SNCR ON COLSTRIP UNIT 2

Description	Cost ($)
Total Annual Cost SOFA	1,090,395
Total Annual Cost SNCR	2,165,732
Total Annual Cost SOFA+SNCR	3,256,127

TABLE 95—SUMMARY OF NO_X BART COSTS FOR SOFA+SNCR ON COLSTRIP UNIT 2

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
13.381	3.256	2,072	1,571

SOFA+SCR

We relied on control costs developed for the IPM for direct capital costs for SCR.[159] We then used methods in the CCM for the remainder of the SOFA+SCR analysis. Specifically, we used the methods in the CCM to calculate total capital investment, annual costs associated with operation and maintenance, to annualize the total capital investment using the CRF, and to sum the total annual costs.

We used a retrofit factor of ''1'' in the IPM control costs, which reflects an SCR retrofit of typical difficulty. We used an aqueous ammonia (29%) cost of $240 per ton,[160] and a catalyst cost of $6,000 per cubic meter.[161] To estimate the average cost effectiveness (dollars per ton of emissions reductions) we divided the total annual cost by the estimated NO_X emissions reductions. We summarize the costs from our SOFA+SCR cost analysis in Tables 96, 97, and 98.

TABLE 96—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR SOFA+SCR ON COLSTRIP UNIT 2

Description	Cost ($)
Capital Investment SOFA	4,507,528
Capital Investment SCR	78,263,720
Total capital Investment SOFA + SCR	82,771,248

TABLE 97—SUMMARY OF NO_X BART TOTAL ANNUAL COST ANALYSIS FOR SOFA+SCR ON COLSTRIP UNIT 2

Description	Cost ($)
Total Annual Cost SOFA	1,090,395

[156] IPM, Chapter 5, Appendix 5–2B.

[157] Cost and Quality of Fuels for Electric Utility Plants 1999 Tables, Energy Information Administration, DOE/EIA–0191(99), June 2000, Table 24.

[158] NO_X Control Update to PPL Montana's Colstrip Generating Station BART Report Prepared for PPL Montana, LLC, by TRC, September 2011, p. 4–1.

[159] IPM, Chapter 5, Appendix 5–2A.

[160] Email communication with Fuel Tech, Inc., March 2, 2012.

[161] Cichanowicz 2010, p. 6–7.

TABLE 97—SUMMARY OF NO_X BART TOTAL ANNUAL COST ANALYSIS FOR SOFA+SCR ON COLSTRIP UNIT 2—Continued

Description	Cost ($)
Total Annual Cost SCR	9,830,104
Total Annual Cost SOFA+SCR	10,920,499

TABLE 98—SUMMARY OF NO_X BART COSTS FOR SOFA+SCR ON COLSTRIP UNIT 2

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tons/yr)	Average cost effectiveness ($/ton)
82.771	10.920	3,376	3,235

Factor 2: Energy Impacts

An SNCR process reduces the thermal efficiency of a boiler as the reduction reaction uses thermal energy from the boiler.[162] Therefore, additional coal must be burned to make up for the decreases in power generation. Using CCM calculations we determined the additional coal needed for Unit 2 equates to 75,800 MMBtu/yr. For an SCR, the new ductwork and the reactor's catalyst layers decrease the flue gas pressure. As a result, additional fan power is necessary to maintain the flue gas flow rate through the ductwork. SCR systems require additional electric power to meet fan requirements equivalent to approximately 0.3% of the plant's electric output.[163] Both SCR and SNCR require some minimal additional electricity to service pretreatment and injection equipment, pumps, compressors, and control systems. The additional energy requirements that would be involved in installation and operation of the evaluated controls are not significant enough to warrant eliminating any of the options evaluated. Note that cost of the additional energy requirements has been included in our calculations.

Factor 3: Non-Air Quality Environmental Impacts

The non-air quality environmental impacts for Colstrip Unit 2 are the same as for Colstrip Unit 1, see previous discussion for Colstrip Unit 1.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. Thus, this factor does not impact our BART determination because the annualized cost was calculated over a 20 year period in accordance with the BART Guidelines.

Factor 5: Evaluate Visibility Impacts

We conducted modeling for Colstrip Unit 2 as described in section V.C.3.a. Table 99 presents the visibility impacts of the 98th percentile of daily maxima for each Class I area from 2006 through 2008. Table 100 presents the number of days with impacts greater than 0.5 deciviews for each Class area from 2006 through 2008.

TABLE 99—DELTA DECIVIEW IMPROVEMENT FOR NO_X CONTROLS ON COLSTRIP UNIT 2

Class I area	Baseline impact (delta deciview)	Improvement from SOFA+SCR (delta deciview)	Improvement from SOFA+SNCR (delta deciview)	Improvement from SOFA (delta deciview)
North Absaroka WA	0.402	0.185	0.083	0.055
Theodore Roosevelt NP	0.895	0.423	0.269	0.190
UL Bend WA	0.889	0.406	0.269	0.185
Washakie WA	0.392	0.143	0.089	0.063
Yellowstone NP	0.289	0.091	0.071	0.063

TABLE 100—DAYS GREATER THAN 0.5 DECIVIEW FOR NO_X CONTROLS ON COLSTRIP UNIT 2

[Three year total]

Class I Area	Baseline (days)	Using SOFA+SCR	Using SOFA+SNCR	Using SOFA
North Absaroka WA	8	5	5	7
Theodore Roosevelt NP	54	14	25	35
UL Bend WA	66	17	41	46
Washakie WA	12	5	8	11
Yellowstone NP	4	2	2	2

[162] CCM, Section 4.2, Chapter 1, p. 1–21.

[163] CCM, Section 4.2, Chapter 2, p. 2–28.

Step 5: Select BART

We propose to find that BART for NO_X is SOFA+SNCR at Colstrip Unit 2 with an emission limit of 0.15 lb/MMBtu (30-day rolling average). Of the five BART factors, cost and visibility improvement were the critical ones in our analysis of controls for this source.

In our BART analysis for NO_X at Colstrip Unit 2, we considered SOFA, SOFA+SNCR, and SOFA+SCR. The comparison between our SOFA, SOFA+SNCR, and SOFA+SCR analysis is provided in Table 101.

TABLE 101—SUMMARY OF NO_X BART ANALYSIS COMPARISON OF CONTROL OPTIONS FOR COLSTRIP UNIT 2

Control option	Total capital investment (MM$)	Total annual cost (MM$)	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility Impacts [1]	
					Visibility Improvement (delta deciviews)	Fewer days > 0.5 deciview
SOFA+SCR	82.771	10.920	3,235	5,877	0.423 TRNP 0.406 UL Bend	40 TRNP 49 UL Bend
SOFA+SNCR	13.380	3.256	1,571	3,322	0.269 TRNP 0.269 UL Bend	29 TRNP 25 UL Bend
SOFA	4.508	1.090	768	[2]	0.190 TRNP 0.185 UL Bend	19 TRNP 20 UL Bend

TRNP—Theodore Roosevelt National Park.
UL Bend—UL Bend Wilderness Area.
[1] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2006 through 2008) at the Class I areas in the table.
[2] Incremental cost is not applicable to the option that has the lowest effectiveness.

We have concluded that SOFA, SOFA+SNCR, and SOFA+SCR are all cost effective control technologies. SOFA has a cost effectiveness value of $768 per ton of NO_X emissions reduced. SOFA+SNCR is more expensive than SOFA, with a cost effectiveness value of $1,571 per ton of NO_X emissions reduced. SOFA+SCR is more expensive than SOFA or SOFA+SNCR, having a cost effectiveness value of $3,235 per ton of NO_X emissions reduced. This is well within the range of values we have considered reasonable for BART and that states have considered reasonable for BART.

We have weighed costs against the anticipated visibility impacts for Colstrip Unit 2. Any of the control options would have a positive impact on visibility; however, the cost of SOFA+SCR ($3,322) is not justified by the visibility improvement of 0.423 deciviews at TRNP and 0.404 deciviews at UL Bend. The lower cost of SOFA+SNCR ($1,571/ton) is justified when the visibility improvement is considered. SOFA+SNCR would have a visibility improvement of 0.269 deciviews at Theodore Roosevelt NP and 0.269 deciviews at UL Bend WA and it would result in 29 fewer days above 0.5 deciviews at Theodore Roosevelt NP and 25 fewer days above 0.5 deciviews at UL Bend WA. In addition, application of SOFA+SNCR at both Colstrip Units 1 and 2 would have a combined modeled visibility improvement of 0.501 deciviews at Theodore Roosevelt NP and 0.451 deciviews at UL Bend WA. We consider these improvements to be substantial, especially in light of the fact that Theodore Roosevelt NP and UL Bend WA are not projected to meet the URP. We propose that the NO_X BART emission limit for Colstrip Unit 2 should be based on what can be achieved with SOFA + SNCR.

The proposed BART emission limit of 0.15 lb/MMBtu allows for a sufficient margin of compliance for a 30-day rolling average limit that would apply at all times, including startup, shutdown, and malfunction.[164] We are also proposing monitoring, recordkeeping, and reporting requirements as described in our proposed regulatory text for 40 CFR 52.1395.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.'' We propose a compliance deadline of five (5) years from the date our final FIP becomes effective because of the equipment installation and potential combustion modifications that will be required.

SO_2

Colstrip Unit 2 is already controlled by wet venturi scrubbers, which are identical to Colstrip Unit 1 scrubbers, for simultaneous particulate and SO_2 control. The venturi scrubbers utilize the alkalinity of the fly ash to achieve an estimated SO_2 removal efficiency of 75%.[165] Based on emissions data from CAMD, for the baseline period 2008 through 2010, the average SO_2 emission rate was 0.418 lb/MMBtu and the average SO_2 emissions were 5,548 tpy.[166]

Step 1: Identify All Available Technologies

The Colstrip Unit 2 venturi scrubber currently achieves greater than 50% removal of SO_2. The available technologies for Colstrip Unit 2 are the same as those for Colstrip Unit 1; see Step 1 analysis for Colstrip Unit 1.

Step 2: Eliminate Technically Infeasible Options

Elimination of bypass reheat is not a feasible option because Colstrip Unit 2 is designed so that there is no bypass of flue gas. Installation of perforated trays is not a feasible option because the existing scrubber design already includes this technology in the form of wash trays. Finally, the use of organic acid additives is not a feasible option because the reactivity of the lime would neutralize the acids, making the additives ineffective.

Lime injection or lime injection with an additional scrubber vessel are technically feasible control options because lime injection is currently used to control SO_2 emissions at Colstrip Units 3 and 4.

[164] As discussed in the BART Guidelines, section V (70 FR 39172, July 6, 2005), and Section 302(k) of the CAA, emissions limits such as BART are required to be met on a continuous basis.

[165] Colstrip Initial Response, p. ES–3.

[166] Clean Air Markets—Data and Maps: *http://camddataandmaps.epa.gov/gdm.*

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

An annual emission rate of 0.015 lb/MMBtu can be achieved with lime injection without an additional scrubber vessel. PPL stated that this is the lowest emission rate that could be achieved without adding an additional scrubber vessel.[167] An annual emission rate of 0.08–0.09 lb/MMBtu can be achieved with lime injection with an additional scrubber vessel. This is the emission rate that is being achieved at Colstrip Units 3 and 4 according to emissions data from CAMD.[168] The control effectiveness of each of the control options was calculated using the controlled emission rates that were provided by PPL.

A summary of control efficiencies, emission rates, and resulting emissions and emission reductions, is provided in Table 102. EPA's detailed emissions calculations for Colstrip 2 can be found in the docket.

TABLE 102—SUMMARY OF BART ANALYSIS CONTROL TECHNOLOGIES FOR SO_2 FOR COLSTRIP UNIT 2

Control option	Control effectiveness (%) [1]	Annual emission rate (lb/MMBtu) [2]	Emissions reduction (tpy)	Remaining emissions (tpy)
Lime Injection with Additional Scrubber Vessel	79.7	0.080	4,129	1,049
Lime Injection	62.0	0.150	3,212	1,966
Existing Controls (Baseline) [3]		0.395		5,178

[1] Control efficiency is provided relative to the emission rate with current controls.
[2] Emission rates are provided on an annual basis.
[3] Baseline emissions for 2008 through 2010 from Clean Air Markets—Data and Maps: *http://camddataandmaps.epa.gov/gdm/*.

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

We relied on capital costs and direct annual costs provided by PPL when determining the cost of compliance for both lime injection and lime injection with an additional scrubber vessel.[169] [170] All costs presented here for the Colstrip Unit 2 SO_2 control options are in year 2007 dollars. EPA's cost calculations for Colstrip 2 can be found in the docket.

Lime Injection

We summarize our cost analysis for lime injection in Tables 103, 104, and 105.

TABLE 103—SUMMARY OF SO_2 CAPITAL COST ANALYSIS FOR LIME INJECTION ON COLSTRIP UNIT 2

Description	Cost ($)
Total Capital Investment	3,000,000

TABLE 104—SUMMARY OF SO_2 BART ANNUAL COST ANALYSIS FOR LIME INJECTION ON COLSTRIP UNIT 2

Description	Cost ($)
Total Direct Annual Cost	1,600,000
Indirect Annual Cost	283,200
Total Annual Cost	1,883,200

TABLE 105—SUMMARY OF SO_2 BART COSTS FOR LIME INJECTION ON COLSTRIP UNIT 2

Total Capital Investment (MM$)	Total Annual Cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
3.000	1.883	3,212	586

Lime Injection With an Additional Scrubber Vessel

We summarize our cost analysis for lime injection with an additional scrubber vessel cost analysis in Tables 106, 107, and 108.

TABLE 106—SUMMARY OF SO_2 CAPITAL COST ANALYSIS FOR LIME INJECTION WITH AN ADDITIONAL SCRUBBER VESSEL ON COLSTRIP UNIT 2

Description	Cost ($)
Total Capital Investment, Lime Injection	3,000,000

[167] Colstrip Addendum, p. 4–1.

[168] Clean Air Markets—Data and Maps: *http://camddataandmaps.epa.gov/gdm/*.

[169] Colstrip Initial Response, Table A4–6(c).

[170] Colstrip Addendum, Table 4.1–4.

TABLE 106—SUMMARY OF SO_2 CAPITAL COST ANALYSIS FOR LIME INJECTION WITH AN ADDITIONAL SCRUBBER VESSEL ON COLSTRIP UNIT 2—Continued

Description	Cost ($)
Capital Investment, Scrubber Vessel	25,000,000
Total Capital Investment	28,000,000

TABLE 107—SUMMARY OF SO_2 BART ANNUAL COST ANALYSIS FOR LIME INJECTION WITH AN ADDITIONAL SCRUBBER VESSEL ON COLSTRIP UNIT 2

Description	Cost ($)
Total Direct Annual Cost	1,450,000
Indirect Annual Cost	2,643,200
Total Annual Cost	4,093,200

TABLE 108—SUMMARY OF SO_2 BART COSTS ANALYSIS FOR LIME INJECTION WITH AN ADDITIONAL SCRUBBER VESSEL ON COLSTRIP UNIT 2

Total installed capital cost (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
$28.000	$4.093	4,129	991

Factor 2: Energy Impacts

According to PPL, the pressure drop of the venturi scrubbers is maintained in the range of 17 to 20 inches of water column. The injection of lime will be accompanied by little to no increase in pressure drop, but it will require a small increase in pump power consumption. This is included in the cost analysis in the additional operations and maintenance expenses of $125,000 per year.[171] The additional energy requirements are not significant enough to warrant eliminating either lime injection or lime injection with an additional scrubber vessel.

Factor 3: Non-Air Quality Environmental Impacts

Adding lime to the scrubbers will require more frequent descaling operations that would increase the quantity of solid waste from descaling operations. Transporting this waste stream for disposal would use natural resources for fuel and would have associated air quality impacts. The disposal of the solid waste itself would be to a landfill and could possibly result in groundwater or surface water contamination if a landfill's engineering controls were to fail. EPA's analysis indicates that the environmental impacts associated with the proper transport and land disposal of the solid waste should not be significant. Therefore, the non-air quality environmental impacts do not warrant eliminating either lime injection addition or lime injection addition with an additional scrubber vessel.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. Because the remaining useful life of the source is equal to that assumed for amortization of control option capital investments, this factor does not impact our BART determination.

Factor 5: Evaluate Visibility Impacts

We conducted modeling for Colstrip Unit 2 as described in section V.C.3.a. Table 109 presents the visibility impacts of the 98th percentile of daily maxima for each Class I area from 2006 through 2008. Table 110 presents the number of days with impacts greater than 0.5 deciviews for each Class I area from 2006 through 2008.

TABLE 109—DELTA DECIVIEW IMPROVEMENT FOR SO_2 CONTROLS ON COLSTRIP 2

Class I area	Baseline impact (delta deciview)	Improvement from lime injection + additional scrubber vessel (delta deciview)	Improvement from lime injection (delta deciview)
North Absaroka WA	0.402	0.140	0.111
Theodore Roosevelt NP	0.895	0.280	0.225
UL Bend WA	0.889	0.179	0.143
Washakie WA	0.392	0.141	0.119
Yellowstone NP	0.289	0.090	0.067

[171] Colstrip Initial Response, p. 4–16.

TABLE 110—DAYS GREATER THAN 0.5 DECIVIEW FOR SO_2 CONTROLS ON COLSTRIP 2

[Three year total]

Class I area	Baseline (days)	Using lime injection + additional scrubber vessel	Using lime injection
North Absaroka WA	7	7	7
Theodore Roosevelt NP	52	33	37
UL Bend WA	68	39	44
Washakie WA	12	7	8
Yellowstone NP	4	2	3

Step 5: Select BART

We propose to find that BART for SO_2 is lime injection with an additional scrubber vessel at Colstrip Unit 2 with an emission limit of 0.08 lb/MMBtu (30-day rolling average). Of the five BART factors, cost and visibility improvement were the critical ones in our analysis of controls for this source.

In our BART analysis for SO_2 at Colstrip Unit 2, we considered lime injection and lime injection with an additional scrubber vessel. The comparison between our lime injection and lime injection with an additional scrubber vessel analysis is provided in Table 111.

TABLE 111—SUMMARY OF EPA SO_2 BART ANALYSIS COMPARISON OF LIME INJECTION AND LIME INJECTION WITH AN ADDITIONAL SCRUBBER VESSEL FOR COLSTRIP UNIT 2

Control option	Total capital investment (MM$)	Total annual cost (MM$)	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts [1]	
					Visibility improvement (delta deciviews)	Fewer days > 0.5 deciview
Lime Injection with Additional Scrubber Vessel.	28.000	4.093	991	2,410	0.280 TRNP 0.179 UL Bend	7 TRNP 8 UL Bend
Lime Injection	3.000	1.883	586	[2]	0.225 TRNP 0.143 UL Bend	6 TRNP 7 UL Bend

TRNP—Theodore Roosevelt National Park.
UL Bend—UL Bend Wilderness Area.
[1] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2006 through 2008) at the Class I areas in the table.
[2] Incremental cost is not applicable to the option that has the lowest effectiveness.

We have concluded that lime injection and lime injection with an additional scrubber vessel are both cost effective control technologies. Lime injection has a cost effectiveness value of $586 per ton of SO_2 emissions reduced. Lime injection with an additional scrubber vessel is more expensive than lime injection, with a cost effectiveness value of $919 per ton of SO_2 emissions reduced. Both of these costs are well within the range of values we have considered reasonable for BART and that states have considered reasonable for BART.

We have weighed costs against the anticipated visibility impacts at Colstrip Unit 2. Either of the control options would have a positive impact on visibility. We have concluded that the cost of lime injection with an additional scrubber vessel ($991/ton) is justified by the visibility improvement of 0.280 deciviews at Theodore Roosevelt NP and 0.179 deciviews at UL Bend WA and it would result in seven fewer days above 0.5 deciviews at Theodore Roosevelt NP and eight fewer days above 0.5 deciviews at UL Bend WA. In addition, the application of lime injection with an additional scrubber vessel on both Colstrip Units 1 and 2 would result in a combined modeled visibility improvement of 0.592 deciviews at Theodore Roosevelt NP and 0.384 deciviews at UL Bend WA. We consider these improvements to be substantial, especially in light of the fact that Theodore Roosevelt NP and UL Bend WA are not projected to meet the URP. We propose that the SO_2 BART emission limit for Colstrip Unit 2 should be based on what can be achieved with lime injection with an additional scrubber vessel.

The proposed BART emission limit of 0.08 lb/MMBtu allows for a sufficient margin of compliance for a 30-day rolling average limit that would apply at all times, including startup, shutdown, and malfunction.[172] We are also proposing monitoring, recordkeeping, and reporting requirements as described in our proposed regulatory text for 40 CFR 52.1395.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.'' We propose a compliance deadline of five (5) years from the date our final FIP becomes effective because of the equipment installation that will be required.

PM

Colstrip Unit 2 currently has venturi scrubbers designed to control PM emissions. A description of a venturi scrubber can be found under the PM section of the BART analysis for Colstrip Unit 1. The venturi scrubbers at Colstrip unit 2 are designed to have at least 98% control efficiency and have shown control efficiencies approximating 99.5%. The present emission rate is 0.0525 lb/MMBtu.[173]

[172] As discussed in the BART Guidelines, section V (70 FR 39172, July 6, 2005), and Section 302(k) of the CAA, emissions limits such as BART are required to be met on a continuous basis.

[173] Colstrip Addendum, p. 6–1.

Based on our modeling described in section V.C.3.a. PM contribution to the baseline visibility impairment is low. Table 112 shows the maximum baseline visibility impact and percentage contribution to that impact from coarse PM and fine PM.

TABLE 112—COLSTRIP UNIT 2 VISIBILITY IMPACT CONTRIBUTION FROM PM

Maximum baseline visibility impact (deciview)	% Contribution coarse PM	% Contribution fine PM
0.895	0.95	3.88

The PM contribution to the baseline visibility impact for Colstrip Unit 2 is very small; therefore, any visibility improvement that could be achieved with improvements to the existing PM controls would be negligible. We are proposing that the existing PM control device represents BART.

Colstrip Unit 2 must meet the filterable PM emission standard of 0.1lb/MMBtu in accordance with its Final Title V Operating Permit #OP0513–06. This requirement appears in Permit Condition B.2.; and was included in the permit pursuant to ARM 17.8.340 and 40 CFR part 60, subpart D.

Taking into consideration the above factors we propose basing the BART emission limit on what Colstrip Unit 2 is currently meeting. The units are exceeding a PM control efficiency of 99%, and therefore we are proposing that the current control technology and the emission limit of 0.1lb/MMBtu for PM/PM_{10} as BART. We find that the BART emission limit can be achieved through the operation of the existing venturi scrubbers. Thus, as described in our BART Guidelines, a full five-factor analysis for PM/PM_{10} is not needed for Colstrip Unit 2.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.'' Since we propose a BART emission limit that represents current operations and no installation is necessary, we propose a compliance deadline of 30 days from the date our final FIP becomes effective.

v. Corette

Background

PPL Montana's Corette Power Plant (Corette), located in Billings, Montana, consists of one electric utility steam generating unit. We previously provided in Section V.C. our reasoning for proposing that this unit is BART-eligible and why it is subject to BART. As explained in section V.C., the document titled ''Identification of BART Eligible Sources in the WRAP Region'' dated April 4, 2005 provides more details on the specific emission units at each facility. Corette's boiler has a nominal gross capacity of 162 MW. The boiler began commercial operation in 1968 and is a tangentially fired pulverized coal boiler that burns PRB sub-bituminous coal as their exclusive fuel.

Although the gross capacity of Corette is below the 750 MW cutoff for which use of the BART Guidelines is mandatory, we have nonetheless followed the guidelines as they ''provide useful advice in implementing the BART provisions of the regional haze rule.'' [174]

We requested a five factor BART analysis for Corette from PPL and the Company submitted that analysis in August 2007 along with updated information in June 2008 and September 2011. PPL's five factor BART analysis information is contained in the docket for this action and we have taken it into consideration in our proposed action.

NO_X

The Corette boiler is a tangential-fired unit with existing low-NO_X burners and CCOFA. The unit is subject to an annual NO_X emission limit of 0.4 lb/MMBtu.

Step 1: Identify All Available Technologies

We identified the following NO_X control technologies are available: SOFA, SNCR, and SCR. Descriptions for each of these NO_X control technologies can be found in the Colstrip 1 evaluation above.

Step 2: Eliminate Technically Infeasible Options

Based on our review all the technologies identified in Step 1 appear to be technically feasible for Corette. In particular, both SCR and SNCR have been widely employed to control NO_X emissions from coal-fired power plants.[175] [176] [177]

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

At tangentially fired boilers firing sub-bituminous coal, SOFA in combination with CCOFA and LNB, can typically achieve emission rates below 0.15 lb/MMBtu on an annual basis.[178] However, due to certain issues unique to Corette, a rate of 0.20 lb/MMBtu is more realistic. Specifically, these issues include: (1) That the furnace is undersized, has a high heat rate, and therefore runs hotter than newer units designed for low NO_X emissions; and (2) the nature of the particular PRB coal burned. The 0.20 lb/MMBtu rate represents a 26.8% reduction from the current baseline (2008 through 2010) rate of 0.274 lb/MMbtu.

The post-combustion control technologies, SNCR and SCR, have been evaluated in combination with combustion controls. That is, the inlet concentration to the post-combustion controls is assumed to be 0.20 lb/MMBtu. This allows the equipment and operating and maintenance costs of the post-combustion controls to be minimized based on the lower inlet NO_X concentration. Typically, SNCR reduces NO_X an additional 20 to 30% above LNB/combustion controls without excessive NH_3 slip.[179] Assuming that a minimum 25% additional emission reduction is achievable with SNCR, SOFA combined with SNCR can achieve an overall control efficiency of 44.9%. SCR can achieve performance emission rates as low as 0.04–0.07 lb/MMBtu on an annual basis.[180] Assuming that an annual emission rate of 0.05 lb/MMBtu is achievable with SOFA+SCR, this equates to an overall control efficiency of 81.2%. A summary of control

[174] 70 FR 39108 (July 6, 2005).

[175] Institute of Clean Air Companies (ICAC) White Paper, SCR Controls of NO_X Emissions from Fossil Fuel-Fired Electric Power Plants, May 2009, pp. 7–8.

[176] Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants, Northeast States for Coordinated Air Use Management (NESCAUM), March 31, 2011, p. 16.

[177] ICAC White Paper, SNCR for Controlling NO_X Emissions, February 2008, pp. 6–7.

[178] Low NO_X Firing Systems and PRB Fuel; Achieving as Low as 0.12 LB NO_X/MMBtu, Jennings, P., ICAC Forum, Feb. 2002.

[179] White Paper, SNCR for Controlling NO_X Emissions, Institute of Clean Air Companies, pp. 4 and 9, February 2008.

[180] Srivastava, R., Hall, R., Khan, S., Lani, B., and Culligan, K., ''Nitrogen oxides emission control options for coal-fired utility boilers,'' Journal of Air and Waste Management Association 55(9):1367–88 (2005). Available at: *http://www.netl.doe.gov/technologies/coalpower/ewr/pubs/NOx%20control%20Lani%20AWMA%200905.pdf.*

efficiencies, emission rates, and resulting emission reductions for the control options under consideration are provided in Table 113. EPA's detailed emissions calculations for Corette can be found in the docket.

TABLE 113—SUMMARY OF NO_X BART ANALYSIS CONTROL TECHNOLOGIES FOR CORETTE

Control option	Control effectiveness (%)	Annual emission rate (lb/MMBtu)	Emissions reduction (tpy)	Remaining emissions (tpy)
SOFA+SCR	81.2	0.050	1,320	305
SOFA+SNCR	44.9	0.150	730	895
SOFA	26.9	0.200	435	1,190
No Controls (Baseline) [1]		0.274		1,625

[1] Baseline emissions were determined by averaging the annual emissions from 2008 to 2010 as reported to the CAMD database available at *http://camddataandmaps.epa.gov/gdm/.*

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

Refer to the Colstrip Unit 1 section above for general information on how we evaluated the cost of compliance for NO_X controls. EPA's cost calculations for NO_X controls at Corette can be found in the docket.

SOFA

We relied on estimates submitted by PPL in 2008 for capital costs and direct annual costs for SOFA.[181] We then used the CEPCI to adjust capital costs to 2010 dollars (see Table 114). Annual costs were determined by summing the indirect annual cost and the direct annual cost (see Table 115).

TABLE 114—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR SOFA ON CORETTE

Description	Cost ($)
Total Capital Investment SOFA	3,350,365

TABLE 115—SUMMARY OF NO_X BART ANNUAL COST ANALYSIS FOR SOFA ON CORETTE

Description	Cost ($)
Total Indirect Annual Cost	330,375
Total Direct Annual Cost	315,754
Total Annual Cost	646,129

TABLE 116—SUMMARY OF NO_X BART COSTS FOR SOFA ON CORETTE

Total installed capital cost (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
3.351	0.646	435	1,487

SOFA+SNCR

We relied on control costs developed for the IPM for direct capital costs for SNCR.[182] We then used methods provided by the CCM for the remainder of the SOFA+SNCR analysis. Specifically, we used the methods in the CCM to calculate total capital investment, annual costs associated with operation and maintenance, to annualize the total capital investment using the CRF, and to sum the total annual costs.

We used a retrofit factor of ''1'' reflecting an SNCR retrofit of typical difficulty in the IPM control costs. Corette burns sub-bituminous PRB coal having a low sulfur content of 0.24 lb/MMBtu.[183] As explained in our analysis for Colstrip Unit 1, it was not necessary to make allowances in the cost calculations to account for equipment modifications or additional maintenance associated with fouling due to the formation of ammonium bisulfate. EPA's detailed cost calculations for SOFA+SNCR can be found in the docket.

We used a urea reagent cost estimate of $450 per ton taken from PPL's September 2011 submittal.[184] To estimate the average cost effectiveness (dollars per ton of emissions reductions) we divided the total annual cost by the estimated NO_X emissions reductions. We summarize the costs from our SPFA+SNCR cost analysis in Tables 117, 118, and 119.

[181] Addendum to PPL Montana's J.E. Corette Generating Station BART Report Prepared for PPL Montana, LLC; Prepared by TRC (''Corette Addendum''), June 2008, Table 5.1–3.

[182] IPM, Chapter 5, Appendix 5–2B.

[183] Cost and Quality of Fuels for Electric Utility Plants 1999 Tables, Energy Information Administration, DOE/EIA–0191(99), June 2000, Table 24.

[184] NO_X Control Update to PPL Montana's J.E. Corette Generating Station BART Report, September 2011, Prepared for PPL Montana, LLC by TRC, p. 8.

TABLE 117—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR SOFA+SNCR ON CORETTE

Description	Cost ($)
Capital Investment SOFA	3,350,365
Capital Investment SNCR	6,464,691
Total Capital Investment SOFA + SNCR	9,815,056

TABLE 118—SUMMARY OF NO_X BART TOTAL ANNUAL COST ANALYSIS FOR SOFA+SNCR ON CORETTE

Description	Cost ($)
Total Annual Cost SOFA	646,129
Total Annual Cost SNCR	1,248,062
Total Annual Cost SOFA+SNCR	1,894,191

TABLE 119—SUMMARY OF NO_X BART COSTS FOR SOFA+SNCR ON CORETTE

Total installed capital cost (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
9.815	1.894	730	2,596

SOFA+SCR

We relied on control costs developed for the IPM for direct capital costs for SCR.[185] We then used methods in the CCM for the remainder of the SOFA+SCR analysis. Specifically, we used the methods in the CCM to calculate total capital investment, annual costs associated with operation and maintenance, to annualize the total capital investment using the CRF, and to sum the total annual costs.

We used a retrofit factor of ''1'' in the IPM control costs, which reflects an SCR retrofit of typical difficulty. We used an aqueous ammonia (29%) cost of $240 per ton,[186] and a catalyst cost of $6,000 per cubic meter.[187] To estimate the average cost effectiveness (dollars per ton of emissions reductions) we divided the total annual cost by the estimated NO_X emissions reductions. We summarize the costs from our SOFA+SCR cost analysis in Tables 120, 121, and 122.

TABLE 120—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR SOFA+SCR ON CORETTE

Description	Cost ($)
Capital Investment SOFA	3.350,365
Capital Investment SCR	42,958,390
Total Capital Investment SOFA+SCR	46,308,755

TABLE 121—SUMMARY OF NO_X BART TOTAL ANNUAL COST ANALYSIS FOR SOFA+SCR ON CORETTE

Description	Cost ($)
Total Annual Cost SOFA	646,129
Total Annual Cost SCR	5,281,486
Total Annual Cost SOFA+SCR	5,927,615

TABLE 122—SUMMARY OF NO_X BART COSTS FOR SOFA+SCR ON CORETTE

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
46.309	5.927	1,320	4,491

Factor 2: Energy Impacts

SNCR reduces the thermal efficiency of a boiler as the reduction reaction uses thermal energy from the boiler.[188] Therefore, additional coal must be burned to make up for the decrease in power generation. Using CCM calculations we determined the additional coal needed for Corette equates to 34,319 MMBtu/yr. For SCR, the new ductwork and the reactor's catalyst layers decrease the flue gas

[185] IPM, Chapter 5, Appendix 5–2A.

[186] Email communication with Fuel Tech, Inc., March 2, 2012.

[187] Cichanowicz 2010, p. 6–7.

[188] CCM, Section 4.2, Chapter 1, p. 1–21.

pressure. As a result, additional fan power is necessary to maintain the flue gas flow rate through the ductwork. SCR systems require additional electric power to meet fan requirements equivalent to approximately 0.3% of the plant's electric output.[189] Both SCR and SNCR require some minimal additional electricity to service pretreatment and injection equipment, pumps, compressors, and control systems. The additional energy requirements that would be involved with operation of the evaluated controls are not significant enough to warrant eliminating any of the options evaluated. Note that the cost of the additional energy requirements has been included in our calculations.

Factor 3: Non-Air Quality Environmental Impacts

The non-air quality environmental impacts for Corette are the same as for Colstrip Unit 1, see previous discussion for Colstrip Unit 1.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. Thus, this factor does not impact our BART determination because the annualized cost was calculated over a 20 year period in accordance with the BART Guidelines.

Factor 5: Evaluate Visibility Impacts

We conducted modeling for Corette as described in section V.C.3.a. Table 123 presents the visibility impacts of the 98th percentile of daily maxima for each Class I area from 2006 through 2008. Table 124 presents the number of days with impacts greater than 0.5 deciviews for each Class area from 2006 through 2008.

TABLE 123—DELTA DECIVIEW IMPROVEMENT FOR NO_X CONTROLS ON CORETTE

Class I area	Baseline impact (delta deciview)	SOFA+SCR (delta deciview)	SOFA+SNCR (delta deciview)	SOFA (delta deciview)
Gates of the Mountains WA	0.295	0.093	0.049	0.028
North Absaroka WA	0.497	0.184	0.103	0.062
Red Rock Lakes WA	0.090	0.029	0.016	0.010
Teton WA	0.298	0.118	0.062	0.042
UL Bend WA	0.462	0.158	0.091	0.057
Washakie WA	0.667	0.264	0.146	0.087
Yellowstone NP	0.325	0.093	0.053	0.033

TABLE 124—DAYS GREATER THAN 0.5 DECIVIEW FOR NO_X CONTROLS ON CORETTE

[Three Year Total]

Class I area	Baseline (days)	Using SOFA+SCR	Using SOFA+SNCR	Using SOFA
Gates of the Mountains WA	4	2	3	3
North Absaroka WA	11	7	9	10
Red Rock Lakes WA	0	0	0	0
Teton WA	7	2	6	7
UL Bend WA	14	2	5	8
Washakie WA	20	7	13	13
Yellowstone NP	7	2	3	4

Step 5. Select BART

We propose to find that BART for NO_X is the existing tangential firing design of the boilers and existing low-NO_X burners with close coupled over fire air at Corette with an emission limit of 0.40 lb/MMBtu (annual average). Of the five BART factors, cost and visibility improvement were the critical ones in our analysis of controls for this source.

In our BART analysis for NO_X at Corette, we considered SOFA, SOFA+SNCR, and SOFA+SCR. The comparison between our SOFA, SOFA+SNCR, and SOFA+SCR analysis is provided in Table 125.

TABLE 125—SUMMARY OF NO_X BART ANALYSIS COMPARISON OF CONTROL OPTIONS FOR CORETTE

Control option	Total capital investment (MM$)	Total annual cost (MM$)	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts [1]	
					Visibility improvement (delta deciviews)	Fewer days > 0.5 deciview
SOFA+SCR	46.309	5.927	4,491	6,836	0.264	13
SOFA+SNCR	9.815	1.894	2,596	4,231	0.146	9
SOFA	3.350	0.646	1,487	[2]	0.087	7

[1] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2006 through 2008) is for Washakie WA, the Class I area with the greatest change, except that the fewer days >0.5 deciview for SOFA+SNCR is for UL Bend WA.

[2] Incremental cost is not applicable to the option that has the lowest effectiveness.

[189] Id., Section 4.2, Chapter 2, p. 2–28.

We have concluded that SOFA, SOFA+SNCR, and SOFA+SCR are all cost effective control technologies. SOFA has a cost effectiveness value of $1,487 per ton of NO_X emissions reduced. SOFA+SNCR is more expensive than SOFA, with a cost effectiveness value of $2,596 per ton of NO_X emissions reduced. SOFA+SCR is more expensive than SOFA or SOFA+SNCR, having a cost effectiveness value of $4,491 per ton of NO_X emissions reduced. This is well within the range of values we have considered reasonable for BART and that states have considered reasonable for BART.

We have weighed costs against the anticipated visibility impacts for Corette. Any of the control options would have a positive impact on visibility; however, the cost of controls is not justified by the visibility improvement.

In proposing a BART emission limit of 0.40 lb/MMBtu, we evaluated the existing emissions from the facility and determined this rate to allow for a sufficient margin of compliance for a 30-day rolling average limit that that would apply at all times, including startup, shutdown, and malfunction.[190] We are also proposing monitoring, recordkeeping, and reporting requirements as described in our proposed regulatory text for 40 CFR 52.1395.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.'' Since we propose a BART emission limit that represents current operations and no installation is necessary, we propose a compliance deadline of 30 days from the date our final FIP becomes effective.

SO_2

The Corette boiler currently burns very low-sulfur PRB sub-bituminous coal with a sulfur content of 0.3% by weight.[191] The boiler is subject to a fuel sulfur limit of 1 lb/MMBtu (as fired) on a continuous basis and an annual emission limit of 9,990,00 lbs/calendar year.[192]

Step 1: Identify All Available Technologies

We identified that three flue gas desulfurization (FGD or ''scrubbing'') technologies as available control technologies for consideration at Corette. Two of these options, dry sorbent injection (DSI) and semi-dry scrubbing (sometimes referred to as LSD), are dry scrubbing technologies. The third option is a wet scrubbing technology known as limestone forced oxidation (LSFO). We did not consider fuel-switching options as Corette already burns very low-sulfur coal.

DSI is the injection of dry sorbent reagents that react with SO_2 and other acid gases, with a downstream PM control device (ESP or baghouse) to capture the reaction products. Unlike wet or semi-dry scrubbing, a reaction chamber is not necessary and reagents are introduced directly into the existing ductwork. Trona, a naturally occurring mixture of sodium carbonate and sodium bicarbonate mined in some western states, is commonly used as a reagent in DSI systems.[193] DSI is typically more attractive for smaller boilers.

In a LSD system, the polluted gas stream is brought into contact with the alkaline sorbent in a semi-dry state through use of a spray dryer absorber. The term ''dry'' refers to the fact that, although water is added to the flue gas, the amount of water added is only just enough to maintain the gas above the saturation (dew point) temperature. In most cases, the reaction products and any unreacted lime from the LSD process are captured in a downstream fabric filter (baghouse), which helps provide additional capture of SO_2.[194]

In LSFO, the polluted gas stream is brought into contact with a liquid alkaline sorbent (typically limestone) by forcing it through a pool of the liquid slurry or by spraying it with the liquid. In the absorber, the gas is cooled to below the saturation temperature, resulting in a wet gas stream and high rates of capture. Because a wet FGD system operates at low temperatures, it is usually the last pollution control device before the stack. The wet FGD absorber is typically located downstream of the PM control device (most often an ESP) and immediately upstream of the stack.[195]

There are several variations of the scrubbing systems described above. However, as discussed in the NO_X control evaluation, the BART Guidelines do not require that all variations be evaluated. The particular variations that we have identified here—DSI with trona, LSD, and LSFO—represent designs that have been successfully applied in a cost-effective manner at numerous utility boilers.

Step 2: Eliminate Technically Infeasible Options

Based on our review, all the technologies identified in Step 1 appear to be technically feasible for Corette. Using these technologies, over 480 power plant boilers, representing nearly two-thirds of the electric generating capacity in the United States, are scrubbed or are projected to be scrubbed in the near future.[196]

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

The control effectiveness of DSI, when located upstream of an ESP (as would be the case at Corette), is in the range of 30 to 60%.[197] For the purposes of our BART analysis for Corette, we assumed a SO_2 removal target for DSI of 50%, which is at the upper end of this range. Higher control efficiencies can be achieved with DSI in conjunction with a baghouse. However, as described under the PM control evaluation, replacement of the existing ESP with a new baghouse is not warranted under BART.

The control effectiveness of LSD or LSFO is dependent on the sulfur content of the coal burned, with greater removal efficiencies being achieved with higher sulfur coals. LSD, which is more commonly applied to lower sulfur coals, can achieve control efficiencies of 70 to 95%, while LSFO can routinely achieve control efficiencies of 95% when applied to higher sulfur coals.[198] Because the control efficiency varies significantly with the inlet sulfur concentration, we evaluated the control effectiveness of LSD and LSFO based on the performance rate that can be achieved. Specifically, we aligned the performance rate with the ''floor'' assumed for retrofits in the IPM control cost methodology.[199] On an annual basis, these rates are 0.065 lb/MMBtu and 0.060 lb/MMBtu for LSD and LSFO, respectively.

A summary of control efficiencies, emission rates, and resulting emission reductions for the control options under consideration are provided in Table 126.

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[190] As discussed in the BART Guidelines, section V (70 FR 39172, July 6, 2005), and Section 302(k) of the CAA, emissions limits such as BART are required to be met on a continuous basis.

[191] BART Assessment J.E. Corette Generating Station, prepared for PPL Montana, LLC, by TRC, (''Corette Initial Response''), August 2007, p. 4–9.

[192] MDEQ, Final Operating Permit #OP2953–05, for PPL Montana, LLC, JE Corette Steam Electric Station, 9.25/09.

[193] Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants, NESCAUM, March 31, 2011, p. 13.

[194] *Id.,* p. 11.

[195] *Id.,* p. 10.

[196] *Id.,* p. 10.

[197] *Id.,* p. 13.

[198] ICAC, Acid Gas/SO_2 Control Technologies, *http://www.icac.com/i4a/pages/index.cfm?pageid=3401.*

[199] Documentation for IPM v. 4.1, Table 5–2.

TABLE 126—SUMMARY OF SO_2 BART ANALYSIS CONTROL TECHNOLOGIES FOR CORETTE

Control option	Control effectiveness (%)	Annual emission rate (lb/MMBtu)	Emissions reduction (tpy)	Remaining emissions (tpy)
LSFO	87.0	0.060	2,369	354
LSD	85.9	0.065	2,339	384
DSI	50.0	0.232	1,362	1,361
No Controls (Baseline) [1]	NA	0.461		2,723

[1] Baseline emissions were determined by averaging the annual emissions from 2008 to 2010 as reported to the CAMD database available at *http://camddataandmaps.epa.gov/gdm/*. A summary of this information can be found in our docket.

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of compliance

In accordance with the BART Guidelines (70 FR 39166 (July 6, 2005)), and in order to maintain and improve consistency, we sought to align our cost analysis for SO_2 controls with the CCM. In a manner similar to our evaluation of costs for NO_X controls as described above, we relied on the cost methods developed for IPM version 4.10. However, unlike our evaluation of costs for NO_X controls, we relied on the IPM cost methods for both the capital costs and operating and maintenance costs (*i.e.,* direct annual costs). The IPM cost methods for both capital and operation and maintenance costs for SO_2 controls are more appropriate to utility boilers than the methods for industrial processes found in the CCM. Our costs were also informed by cost analyses submitted by PPL. EPA's detailed cost calculations for each of the SO_2 control options can be found in the docket.

Annualization of capital investments was achieved using the CRF as described in the CCM.[200] Unless noted otherwise, the CRF was computed using an economic lifetime of 20 years and an annual interest rate of 7%.[201] All costs presented in this proposal are adjusted to 2010 dollars using the CEPCI.[202] EPA's detailed cost calculations can be found in the docket.

DSI

The specific methods that we relied upon for evaluating costs for DSI are found in Appendix 5–4 to the IPM v.4.1 documentation. Our costs are based on utilization of the existing ESP to handle the increased particulate loading associated with injection of dry sorbent. This is consistent with the SO_2 control efficiency of 50% that we assumed for DSI in conjunction with ESP. We used a retrofit factor of ''1'' reflecting a DSI retrofit of typical difficulty in the IPM control costs. We used a reagent cost of $145/ton of trona, consistent with the assumption in the IPM cost methods. We summarize the costs from our DSI cost analysis in Tables 127, 128, and 129.

TABLE 127—SUMMARY OF SO_2 BART CAPITAL COST ANALYSIS FOR DSI ON CORETTE

Description	Cost ($)
Total Capital Investment	10,311,531

TABLE 128—SUMMARY OF EPA SO_2 BART ANNUAL COST ANALYSIS FOR DSI ON CORETTE

Description	Cost ($)
Total Indirect Annual Cost	973,409
Total Direct Annual Cost	4,390,487
Total Annual Cost	5,363,896

TABLE 129—SUMMARY OF SO_2 BART COSTS FOR DSI ON CORETTE

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
10.311	5.364	1,361	3,940

Semi-dry Scrubbing with LSD

The specific methods that we relied upon for evaluating costs for LSD can be found in Appendix 5–1B to the IPM v.4.1 documentation. We used a retrofit factor of ''1'' reflecting a LSD retrofit of typical difficulty in the IPM control costs. We summarize the costs from our LSD cost analysis in Tables 130, 131, and 132.

[200] CCM, Section 1, Chapter 2, p. 2–21.

[201] Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

[202] Chemical Engineering Magazine, p. 56, August 2011. (*http://www.che.com*).

TABLE 130—SUMMARY OF SO_2 BART CAPITAL COST ANALYSIS FOR LSD ON CORETTE

Description	Cost ($)
Total Capital Investment	93,175,857

TABLE 131—SUMMARY OF EPA SO_2 BART ANNUAL COST ANALYSIS FOR LSD ON CORETTE

Description	Cost ($)
Total Indirect Annual Cost	8,795,801
Total Direct Annual Cost	3,932,763
Total Annual Cost	12,728,564

TABLE 132—SUMMARY OF SO_2 BART COSTS FOR LSD ON CORETTE

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tons/yr)	Average cost effectiveness ($/ton)
93.175	12.728	2,339	5,442

Wet Scrubbing With LSFO

The specific methods that we relied upon for evaluating costs for LSFO can be found in Appendix 5–1A to the IPM v.4.1 documentation. We used a retrofit factor of ''1'' reflecting a LSFO retrofit of typical difficulty in the IPM control costs. We summarize the costs from our LSFO cost analysis in Tables 133, 134, and 135.

TABLE 133—SUMMARY OF SO_2 BART CAPITAL COST ANALYSIS FOR LSFO ON CORETTE

Description	Cost ($)
Total Capital Investment	98,352,945

TABLE 134—SUMMARY OF EPA SO_2 BART ANNUAL COST ANALYSIS FOR LSFO ON CORETTE

Description	Cost ($)
Total Indirect Annual Cost	9,284,518
Total Direct Annual Cost	5,792,020
Total Annual Cost	15,076,538

TABLE 135—SUMMARY OF SO_2 BART COSTS FOR LSFO ON CORETTE

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
98.352	15.076	2,369	6,365

Factor 2: Energy Impacts

Auxiliary power requirements were calculated consistent with the methods found in the IPM cost model for variable operating and maintenance costs. DSI requires additional power of 0.19% of the plant's electrical output for air blowers for the injection system, drying equipment for the transport air, and in-line trona milling equipment. LSD and LSFO require additional power of 1.64% and 1.42% of the plant's electrical output, respectively, to meet power requirements primarily associated with increased fan power to overcome the pressure drop of the FGD system. The average annual gross output of the Corette facility between 2008 and 2010 was 1,084,455 MW-hours (MWh). The additional annual power needs associated with DSI, LSD, and LSFO equate to 2,060 MWh, 17,785 MWh, and 15,399 MWh, respectively. We find that the additional energy requirements are not significant enough to warrant elimination of any of the SO_2 control options under consideration.

Factor 3: Non-air Quality Environmental Impacts

Non-air quality environmental impacts for the SO_2 control options under consideration for Corette include increased waste disposal, and with the exception of DSI, water usage.

Waste disposal rates were calculated consistent with the methods found in the IPM cost model for variable operation and maintenance costs; PPL currently sells the fly ash generated at Corette. However, with the addition of a sodium sorbent used in DSI, any fly ash produced must be landfilled.

Therefore, the total waste disposal rate includes waste associated with both fly ash and sorbent. The hourly waste generation rate for DSI is 9.51 tons/hr. For both LSD and LSFO, the waste generation rate is directly proportional to the reagent usage and is estimated based on 10% moisture in the by-product. The hourly waste generation rates for LSD and LSFO are 1.41 tons/hr and 1.42 tons/hr, respectively. The average annual hours of operation at the Corette facility between 2008 and 2010 were 7,513 hours. The annual waste generation rates associated with DSI, LSD, and LSFO equate to 71,448 tons/yr, 10,593 tons/yr, and 10,668 tons/yr, respectively.

Makeup water rates were calculated consistent with the methods found in the IPM cost model for variable operation and maintenance costs. The makeup water rates for LSD and LSFO are a function of gross unit size (actual gas flow rate) and sulfur feed rate. The hourly makeup water rates for LSD and LSFO are 11,290 gallons/hr and 15,380 gallons/hr, respectively. These rates equate to an increase of annual consumption of 85,024,990 gallons/yr and 115,813,373 gallons/yr, respectively.

With the exception of water use explained above, we find that the non-air quality environmental impacts are not significant enough to warrant elimination of any of the SO_2 control options under consideration.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. Thus, this factor does not impact our BART determination because the annualized cost was calculated over a 20 year period in accordance with the BART Guidelines.

Factor 5: Evaluate Visibility Impacts.

We conducted modeling for Corette as described in section V.C.3.a. Table 136 presents the visibility impacts of the 98th percentile of daily maxima for each Class I area from 2006 through 2008. Table 137 presents the number of days with impacts greater than 0.5 deciviews for each Class area from 2006 through 2008.

TABLE 136—DELTA DECIVIEW IMPROVEMENT FOR SO_2 CONTROLS ON CORETTE

Class I area	Baseline impact (Delta deciview)	LSFO (Delta deciview)	LSD (Delta deciview)	DSI (Delta deciview)
Gates of the Mountains WA	0.295	0.147	0.145	0.090
North Absaroka WA	0.497	0.148	0.147	0.093
Red Rock Lakes WA	0.090	0.044	0.043	0.025
Teton WA	0.298	0.114	0.112	0.065
UL Bend WA	0.462	0.168	0.168	0.101
Washakie WA	0.667	0.256	0.253	0.176
Yellowstone NP	0.325	0.135	0.134	0.097

TABLE 137—DAYS GREATER THAN 0.5 DECIVIEW FOR SO_2 CONTROLS ON CORETTE (THREE YEAR TOTAL)

Class I area	Baseline (days)	Using LSFO	Using LSD	Using DSI
Gates of the Mountains WA	4	2	2	3
North Absaroka WA	11	8	8	9
Red Rock Lakes WA	0	0	0	0
Teton WA	7	4	4	5
UL Bend WA	14	4	4	6
Washakie WA	20	8	8	12
Yellowstone NP	7	3	3	4

Step 5: Select BART.

We propose to find that BART for SO_2 is the existing operation at Corette with an emission limit of 0.70 lb/MMBtu (annual average). Of the five BART factors, cost and visibility improvement were the critical ones in our analysis of controls for this source.

In our BART analysis for SO_2 at Corette, we considered DSI, LSD, and LSFO. The comparison between our DSI, LSD, and LSFO analysis is provided in Table 138.

TABLE 138—SUMMARY OF EPA SO_2 BART ANALYSIS COMPARISON OF DSI, LSD, AND LSFO FOR CORETTE

Control option	Total capital investment (MM$)	Total annual cost (MM$)	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility Impacts [1]	
					Visibility improvement (delta deciviews)	Fewer days > 0.5 deciview
LSFO	98.352	15.076	6,365	78,266	0.256	12
LSD	93.175	12.728	5,442	7,530	0.253	12
DSI	10.312	5.364	3,940	[2]	0.176	8

[1] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2006 through 2008) is for Washakie WA, the Class I area with the greatest change.

[2] Incremental cost is not applicable to the option that has the lowest effectiveness.

We have concluded that DSI is a cost effective control technology. DSI has a cost effectiveness value of $3,940 per ton of NO_X emissions reduced. This is within the range of values we have considered reasonable for BART and that states have considered reasonable for BART. We have concluded that LSD and LSFO are not cost effective. LSD has a cost effectiveness of $5,442 per ton of SO_2 emissions reduced and LSFO has a cost effectiveness of $6,365 per ton of SO_2 emissions reduced.

We have weighed costs against the anticipated visibility impacts at Corette. Any of the control options would have a positive impact on visibility; however, the cost of controls is not justified by the visibility improvement.

In proposing a BART emission limit of 0.70 lb/MMBtu, we evaluated the existing emissions from the facility and determined this rate to allow for a sufficient margin of compliance for an annual average limit that would apply at all times, including startup, shutdown, and malfunction.[203] We are also proposing monitoring, recordkeeping, and reporting requirements as described in our proposed regulatory text for 40 CFR 52.1395.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.'' Since we propose a BART emission limit that represents current operations and no installation is necessary, we propose a compliance deadline of 30 days from the date our final FIP becomes effective.

PM

Corette currently has an ESP for particulate control. ESP is a particle control device that uses electrical forces to move the particles out of the flowing gas stream and onto collector plates. The ESP places electrical charges on the particles, causing them to be attracted to oppositely charged metal plates located in the precipitator. The particles are removed from the plates by ''rapping'' and collected in a hopper located below the unit. The removal efficiencies for ESPs are highly variable; however, for very small particles alone, the removal efficiency is about 99%.[204] The ESP at Corette is designed to achieve a 96% control efficiency, but is currently operating at 98.5%.[205] The present emission annual average filterable particulate emission rate is 0.082 lb/MMBtu.[206]

Based on our modeling described in section V.C.3.a., PM contribution to the baseline visibility impairment is low. Table 139 shows the maximum baseline visibility impact and percentage contribution to that impact from coarse PM and fine PM.

TABLE 139—CORETTE VISIBILITY IMPACT CONTRIBUTION FROM PM

Maximum baseline visibility impact (deciview)	% Contribution coarse PM	% Contribution fine PM
0.497	1.97	2.42

The PM contribution to the baseline visibility impact for Corette is very small; therefore, any visibility improvement that could be achieved with improvements to the existing PM controls would be negligible.

Corette must meet the filterable PM emission standard of 0.26 lb/MMBtu in accordance with its Final Title V Operating Permit #OP2953–05. This Title V requirement appears in Permit Condition H.4.; and was included in the permit pursuant to the regulatory requirements in Montana's EPA approved SIP (ARM 17.8.749).

Taking into consideration the above factors we propose basing the BART emission limit on what Corette is currently meeting. The units are exceeding a PM control efficiency of 99%, and therefore we are proposing that the current control technology and the emission limit of 0.10 lb/MMBtu for PM/PM_{10} as BART. We find that the BART emission limit can be achieved through the operation of the existing ESP. Thus, as described in our BART Guidelines, a full five-factor analysis for PM/PM_{10} is not needed for Corette.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.'' Since we propose a BART emission limit that represents current operations and no installation is necessary, we propose a compliance deadline of 30 days from the date our final FIP becomes effective.

D. Long-Term Strategy/Strategies

1. Emissions Inventories

40 CFR 51.308(d)(3)(iii) requires that EPA 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 Reasonable Progress in each mandatory Class I Federal area Montana affects. EPA must identify the baseline emissions inventory on which its strategies for Montana are based. 40 CFR 51.308(d)(3)(iv) requires that EPA identify all anthropogenic (human-caused) sources of visibility impairment it considered in developing Montana's LTS. This includes major and minor stationary sources, mobile sources, and area sources. In its efforts to meet these requirements, EPA relied on technical analyses developed by WRAP and approved by all state participants, as described below.

Emissions within Montana are both naturally occurring and man-made. Two primary sources of naturally occurring emissions include wildfires and windblown dust. In Montana, the primary sources of anthropogenic emissions include electric utility steam generating units, energy production and processing sources, agricultural production and processing sources, prescribed burning, and fugitive dust sources. The Montana inventory includes emissions of SO_2, NO_X, $PM_{2.5}$, PM_{10}, OC, EC, VOCs, and NH_3.

An emissions inventory for each pollutant was developed by WRAP for Montana for the baseline year 2002 and for 2018, which is the first RP milestone. The 2018 emissions inventory was developed by projecting 2002 emissions and applying reductions expected from federal and state regulations. The emission inventories developed by WRAP were calculated using approved EPA methods.

[203] As discussed in the BART Guidelines, section V (70 FR 39172, July 6, 2005), and Section 302(k) of the CAA, emissions limits such as BART are required to be met on a continuous basis.

[204] EPA Air Pollution Control Online Course, description at *http://www.epa.gov/apti/course422/ce6a1.html.*

[205] Corette Addendum, p. 6–1.

[206] *Id.*

There are ten different emission inventory source categories identified: Point, area, area oil and gas, on-road, off-road, all fire, biogenic, road dust, fugitive dust, and windblown dust. Tables 140 through 145 show the 2002 baseline emissions, the 2018 projected emissions, and net changes of emissions for SO_2, NO_X, OC, EC, $PM_{2.5}$, and PM_{10} by source category in Montana. The methods that WRAP used to develop these emission inventories are described in more detail in the WRAP documents included in the docket.[207]

SO_2 emissions in Montana, shown in Table 140, come mostly from point sources with smaller amounts coming from fire, area, mobile and the oil and gas industry. WRAP assumed more than 6,000 tpy of SO_2 would be reduced at Colstrip due to controls required by the Regional Haze program. Overall, a 12% statewide reduction in SO_2 emissions is expected by 2018.

TABLE 140—MONTANA SO_2 EMISSION INVENTORY—2002 AND 2018

Montana statewide SO_2 emissions [tons/year]

Source category	Baseline 2002	Future 2018	Net change	Percent change
Point	36,888	36,749	−138	−0.4
All Fire	5,134	4,912	−222	−4.3
Biogenic	0	0	0	0
Area	3,236	3,580	344	11
Area Oil and Gas	225	6	−219	−97
On-Road Mobile	1,863	234	−1629	−87
Off-Road Mobile	4,552	282	−4270	−94
Road Dust	11	13	2	20
Fugitive Dust	13	17	4	32.8
Wind Blown Dust	0	0	0	0
Total	51,923	45,794	−6,128	−12

NO_X emissions in Montana, shown in Table 141, are expected to decline 26% by 2018. Off-road and on-road vehicle NO_X emissions are estimated to decline by more than 50,000 tpy from the base case emissions total of approximately 104,000 tpy. WRAP assumed more than 23,000 tpy of NO_X would be reduced at Colstrip by 2018 due to an enforcement action and additional controls required as a result of the regional haze requirements. NO_X emissions from oil and gas sources are projected to increase by 84% (6000 tons). Overall, a 26% statewide reduction in NO_X emissions is expected by 2018.

TABLE 141—MONTANA NO_X EMISSION INVENTORY—2002 AND 2018

Montana statewide NO_X emissions [tons/year]

Source Category	Baseline 2002	Future 2018	Net change	Percent change
Point	53,416	33,508	−19,909	−37
All Fire	15,283	14,632	−652	−4
Biogenic	58,354	58,354	0	0
Area	4,292	5,535	1,244	29
Area Oil and Gas	7,557	13,880	6,323	84
On-Road Mobile	53,597	22,036	−31,560	−59
Off-Road Mobile	50,604	32,054	−18,550	−37
Road Dust	25	29	4	17
Fugitive Dust	14	15	1	11
Wind Blown Dust	0	0	0	0
Total	243,142	180,043	−63,099	−26

Most of the PM OC emissions in Montana are from fires as shown in Table 142. In 2002, natural (non-anthropogenic) wildfire accounted for 38,324 tons of OC emissions while anthropogenic fire accounted for 3,745 tons of OC emission. Anthropogenic fire (human-caused), includes such activities as forestry prescribed burning, agricultural field burning, and outdoor residential burning. Overall, OC emissions are estimated to decline by 3% by 2018.

[207] The WRAP 2002 Plan02d and WRAP 2018 PRP18b inventories cited in Tables 73–78 can be found at *http://vista.cira.colostate.edu/tss/Results/HazePlanning.aspx*.

TABLE 142—MONTANA PARTICULATE MATTER ORGANIC CARBON EMISSION INVENTORY—2002 AND 2018

Montana statewide organic carbon emissions
[tons/year]

Source category	Baseline 2002	Future 2018	Net change	Percent Change
Point	101	267	167	165
All Fire	42,069	40,162	−1,907	−5
Biogenic	0	0	0	0
Area [1]	2788	2974	187	7
On-Road Mobile	455	469	14	3
Off-Road Mobile	718	382	−336	−47
Road Dust	1,271	1,487	216	17
Fugitive Dust	687	760	73	11
Wind Blown Dust	0	0	0	0
Total	48,089	46,502	−1,587	−3

[1] Area Source Oil and Gas emissions are included in Area Source total for OC, EC, and PM.

The primary source of EC is fire as shown in Table 143. In 2002, natural (non-anthropogenic) wildfire accounted for 7,743 tons of EC emissions while anthropogenic fire accounted for 759 tons of OC emissions. Other emissions of note are off-road mobile and on-road mobile sources, particularly those associated with diesel engines. EC emissions are estimated to decrease by 17% by 2018 due mostly to new federal mobile source regulations.

TABLE 143—MONTANA ELEMENTAL CARBON EMISSION INVENTORY—2002 AND 2018

Montana statewide elemental carbon emissions
[tons/year]

Source category	Baseline 2002	Future 2018	Net change	Percent change
Point	17	25	8	49
All Fire	8,502	8,116	−386	−5
Biogenic	0	0	0	0
Area [1]	413	447	34	8
On-Road Mobile	519	159	−361	−69
Off-Road Mobile	2,288	1,001	−1287	−56
Road Dust	87	102	15	17
Fugitive Dust	47	52	5	11
Wind Blown Dust	0	0	0	0
Total	11,873	9,901	−1,971	−17

[1] Area Source Oil and Gas emissions are included in Area Source total for OC, EC, and PM.

As detailed in Tables 144 and 145, the primary sources of PM (both PM_{10} and $PM_{2.5}$) are road, fugitive, and windblown dust (agriculture, mining, construction, and unpaved and paved roads). Overall, PM shows an increase of 8–9% by 2018.

TABLE 144—MONTANA FINE PARTICULATE MATTER EMISSION INVENTORY—2002 AND 2018

Montana statewide $PM_{2.5}$ emissions
[tons/year]

Source category	Baseline 2002	Future 2018	Net change	Percent change
Point	182	294	112	62
All Fire	3,190	3,047	−142	−5
Biogenic	0	0	0	0
Area [1]	2,472	2,754	281	11
On-Road Mobile	0	0	0	0
Off-Road Mobile	0	0	0	0
Road Dust	21,671	25,294	3,623	17
Fugitive Dust	13,276	15,209	1,933	15
Wind Blown Dust	36,448	36,448	0	0
Total	77,239	83,047	5,807	8

[1] Area Source Oil and Gas emissions are included in Area Source total for OC, EC, and PM.

TABLE 145—MONTANA COARSE PARTICULATE MATTER EMISSION INVENTORY—2002 AND 2018

Montana statewide coarse particulate matter emissions
[tons/year]

Source category	Baseline 2002	Future 2018	Net change	Percent change
Point	7,818	11,384	3,566	46
All Fire	9,210	8,808	−401	−4
Biogenic	0	0	0	0
Area [1]	706	790	84	12
On-Road Mobile	270	329	59	22
Off-Road Mobile	0	0	0	0
Road Dust	206,863	241,329	34,467	17
Fugitive Dust	68,373	85,309	16,936	25
Wind Blown Dust	328,036	328,036	0	0
Total	621,276	675,985	54,709	9

[1] Area Source Oil and Gas emissions are included in Area Source total for OC, EC, and PM.

See the WRAP documents included in the docket for details on how the 2018 emissions inventory was constructed. WRAP used this inventory and other states' 2018 emission inventories to construct visibility projection modeling for 2018.

The reduction in point and area emissions shown in Tables 140 through 145 is explained in the WRAP's 2018 point and area source projection on Reasonable Progress inventory (version 2018 PRP 18b, *http://www.wrapair.org/forums/ssjf/pivot.html*). The factors contributing to the reductions included emission reductions due to known controls in place on the emission sources, consent decrees, SIP control measures, and other relevant regulations that have gone into effect since 2002, or will go into effect before the end of 2018. This includes estimates made in 2007 for controls for BART sources. These controls do not include impacts from any future control scenarios that had not been defined by 2007. The reduction in emissions due to the retirement of older equipment was estimated using annual retirement rates and based on expected equipment lifetimes. Unit lifetimes were examined for natural gas-fired electrical generating units (EGU) but no retirements were assumed for coal-fired EGU. The permit limits for a source having a limit were considered in the cases where the projected emissions may have inadvertently exceeded an enforceable emission limit i.e., emissions were adjusted downward to the permit limit.

2. Sources of Visibility Impairment in Montana Class I Areas

In order to determine the significant sources contributing to haze in Montana's Class I areas, EPA relied upon two source apportionment analysis techniques developed by WRAP. The first technique was regional modeling using the Comprehensive Air Quality Model (CAMx) and the PSAT tool, used for the attribution of sulfate and nitrate sources only. The second technique was the 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 through 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 WRAP modeling methodologies is available in the docket.[208] Note that the PSAT analyses used the earlier 2002 Plan 02c and 2018 Base 18b inventories, rather than the 2002 Plan 02d and 2018 PRP 18b inventories that are listed in the tables here. The 2018 Base 18b inventory does not assume BART controls.

The contributions of sulfate and nitrate are based on PSAT while the contributions of OC, EC, $PM_{2.5}$, PM_{10}, and Sea Salt are based on WEP. The PSAT and WEP results presented in Tables 146, 147, and 148 were derived from WRAP analysis. Table 147 shows the contribution of different pollutant species from Montana sources.

TABLE 146—MT SOURCES EXTINCTION CONTRIBUTION 2000–2004 FOR 20% WORST DAYS

Class I area	Pollutant species	Extinction (Mm^{-1})	Species contribution to total extinction (%)	MT sources contribution to species extinction (%)[1]
	Sulfate	4.83	11	4
	Nitrate	1.46	3	18
	OC	20.01	47	5

[208] WRAP TSD.

TABLE 146—MT SOURCES EXTINCTION CONTRIBUTION 2000–2004 FOR 20% WORST DAYS—Continued

Class I area	Pollutant species	Extinction (Mm^{-1})	Species contribution to total extinction (%)	MT sources contribution to species extinction (%)[1]
Anaconda-Pintler WA	EC	2.52	6	6
	$PM_{2.5}$	0.94	2	21
	PM_{10}	2.49	6	21
	Sea Salt	0.26	1	[2]
	Sulfate	5.12	11	6
	Nitrate	1.43	3	31
Bob Marshall WA	OC	22.29	48	33
	EC	2.8	6	36
	$PM_{2.5}$	1.29	3	49
	PM_{10}	3.6	8	60
	Sea Salt	0.03	0	[2]
Cabinet Mountains WA.	Sulfate	6.48	15	3
	Nitrate	2.02	5	14
	OC	16.95	40	25
	EC	2.79	7	25
	$PM_{2.5}$	1.03	2	13
	PM_{10}	2.81	7	16
	Sea Salt	0.1	0	[2]
	Sulfate	5.41	17	8
	Nitrate	1.88	6	30
Gates of the Mountains WA	OC	11.26	35	35
	EC	1.82	6	38
	$PM_{2.5}$	0.75	2	73
	PM_{10}	1.68	5	82
	Sea Salt	0.06	0	[2]
	Sulfate	11.37	8	10
	Nitrate	9.36	7	23
Glacier National Park	OC	87.68	64	44
	EC	11.2	8	45
	$PM_{2.5}$	1.4	1	36
	PM_{10}	5.22	4	42
	Sea Salt	0.28	0	[2]
	Sulfate	16.96	28	3
	Nitrate	16.27	27	16
	OC	9.48	15	40
Medicine Lake WA.				
	EC	2.34	4	40
	$PM_{2.5}$	0.75	1	45
	PM_{10}	4.46	7	51
	Sea Salt	0.03	0	[2]
	Sulfate	5.12	11	6
	Nitrate	1.43	3	31
Mission Mountain WA	OC	22.29	48	33
	EC	2.8	6	36
	$PM_{2.5}$	1.29	3	49
	PM_{10}	3.6	8	60
	Sea Salt	0.03	0	[2]
	Sulfate	4.26	12	1
	Nitrate	1.77	5	1
Red Rock Lakes WA	OC	13.48	39	2
	EC	2.48	7	3
	$PM_{2.5}$	0.95	3	18
	PM_{10}	2.58	7	26
	Sea Salt	0.02	0	[2]
	Sulfate	5.12	11	6
	Nitrate	1.43	3	31
	OC	22.29	48	33
Scapegoat WA	EC	2.8	6	36
	$PM_{2.5}$	1.29	3	49
	PM_{10}	3.6	8	60
	Sea Salt	0.03	0	[2]
	Sulfate	4.83	11	4
	Nitrate	1.46	3	1

TABLE 146—MT SOURCES EXTINCTION CONTRIBUTION 2000–2004 FOR 20% WORST DAYS—Continued

Class I area	Pollutant species	Extinction (Mm^{-1})	Species contribution to total extinction (%)	MT sources contribution to species extinction (%)[1]
Selway-Bitterroot WA	OC	20.01	47	5
	EC	2.52	6	6
	$PM_{2.5}$	0.94	2	21
	PM_{10}	2.49	6	21
	Sea Salt	0.26	1	[2]
	Sulfate	9.78	20	5
	Nitrate	8.01	17	18
	OC	12.76	26	52
U.L. Bend WA	EC	2.08	4	51
	$PM_{2.5}$	0.77	2	75
	PM_{10}	4.01	8	81
	Sea Salt	0.01	0	[2]
	Sulfate	4.26	12	1
	Nitrate	1.77	5	1
	OC	13.48	39	2
Yellowstone NP	EC	2.48	7	3
	$PM_{2.5}$	0.95	3	18
	PM_{10}	2.58	7	26
	Sea Salt	0.02	0	[2]

[1] Contribution of sulfate and nitrate based on PSAT; OC, EC, $PM_{2.5}$, PM_{10}, and Sea Salt contribution based on WEP.
[2] MT sources contribution to sea salt was not included in the WRAP results.

Tables 147 and 148 show influences from sources both inside and outside of Montana.

TABLE 147—SOURCE REGION APPORTIONMENT FOR SO_4 FOR 20% WORST DAYS

[Percentage]

	Montana	Canada	Idaho	Washington	Oregon	Outside domain
Anaconda-Pintler WA	4	14	13	10	7	45
Bob Marshall WA	6	14	5	6	4	47
Cabinet Mountains WA	3	17	7	14	5	48
Gates of the Mountains WA	8	1	4	6	3	48
Glacier NP	10	24	2	6	5	51
Medicine Lake WA	3	50	0	2	1	23
Mission Mountain WA	6	14	5	6	4	47
Red Rock Lakes WA	1	5	8	4	4	46
Scapegoat WA	6	14	5	6	4	47
Selway-Bitterroot WA	4	14	13	10	7	45
U.L. Bend WA	5	34	1	2	1	37
Yellowstone NP	1	5	8	4	4	46

TABLE 148—SOURCE REGION APPORTIONMENT FOR NO_3 FOR 20% WORST DAYS

[Percentage]

	Montana	Canada	Idaho	Washington	Oregon	Outside domain
Anaconda-Pintler WA	18	9	13	15	5	23
Bob Marshall WA	31	11	7	9	3	25
Cabinet Mountains WA	14	9	14	32	7	14
Gates of the Mountains WA	29	13	6	9	2	26
Glacier NP	23	22	9	13	6	23
Medicine Lake WA	16	47	1	6	3	18
Mission Mountain WA	31	11	7	9	3	25
Red Rock Lakes WA	2	1	24	8	6	27
Scapegoat WA	31	11	7	9	3	25
Selway-Bitterroot WA	18	9	13	15	5	23
U.L. Bend WA	18	38	2	5	3	21
Yellowstone NP	2	1	24	8	6	27

3. Other States' Class I Areas Affected by Montana Emissions

Table 149 shows the impact Montana sources have on Class I areas in adjacent states.[209]

TABLE 149—MT SOURCES EXTINCTION CONTRIBUTION 2000–2004, 20% WORST DAYS

Class I area	Pollutant species	Extinction (Mm^{-1})	Species contribution to particle extinction (%)	MT sources contribution to species extinction (%) [1]
Badlands WA	Sulfate	18.85	41	2
	Nitrate	5.85	13	7
	OC	11.78	26	18
	EC	2.59	6	12
	$PM_{2.5}$	0.98	2	4
	PM_{10}	5.94	13	5
	Sea Salt	0.19	0	
Bridger WA	Sulfate	4.99	22	2
	Nitrate	1.43	6	3
	OC	10.55	47	2
	EC	1.99	9	2
	$PM_{2.5}$	1.1	5	8
	PM_{10}	2.51	11	13
	Sea Salt	0.04	0	
Craters of the Moon WA	Sulfate	5.69	18	1
	Nitrate	11.35	35	3
	OC	9.06	28	1
	EC	1.92	6	1
	$PM_{2.5}$	1.04	3	4
	PM_{10}	2.95	9	5
	Sea Salt	0.03	0	
Fitzpatrick WA	Sulfate	4.99	22	2
	Nitrate	1.43	6	3
	OC	10.55	47	2
	EC	1.99	9	2
	$PM_{2.5}$	1.1	5	8
	PM_{10}	2.51	11	13
	Sea Salt	0.04	0	
Grand Teton NP	Sulfate	4.26	17	0
	Nitrate	1.77	7	0
	OC	13.48	53	2
	EC	2.48	10	3
	$PM_{2.5}$	0.95	4	18
	PM_{10}	2.58	10	26
	Sea Salt	0.02	0	
Hells Canyon WA	Sulfate	8.37	14	1
	Nitrate	28.47	49	1
	OC	15.6	27	1
	EC	3.06	5	1
	$PM_{2.5}$	0.66	1	2
	PM_{10}	1.93	3	3
	Sea Salt	0.05	0	
Lostwood NWR	Sulfate	21.4	34	2
	Nitrate	22.94	36	9
	OC	11.05	18	17
	EC	2.84	5	12
	$PM_{2.5}$	0.62	1	7
	PM_{10}	3.93	6	11
	Sea Salt	0.26	0	
North Absaroka NP	Sulfate	4.87	21	7
	Nitrate	1.61	7	16
	OC	11.64	49	15
	EC	1.86	8	15
	$PM_{2.5}$	0.85	4	45
	PM_{10}	2.91	12	56
	Sea Salt	0.01	0	
Teton WA	Sulfate	4.26	17	0
	Nitrate	1.77	7	0
	OC	13.48	53	2
	EC	2.48	10	3

[209] WRAP TSD.

TABLE 149—MT SOURCES EXTINCTION CONTRIBUTION 2000–2004, 20% WORST DAYS—Continued

Class I area	Pollutant species	Extinction (Mm^{-1})	Species contribution to particle extinction (%)	MT sources contribution to species extinction (%) [1]
	$PM_{2.5}$	0.95	4	18
	PM_{10}	2.58	10	26
	Sea Salt	0.02	0	
Theodore Roosevelt NP	Sulfate	17.53	35	3
	Nitrate	13.74	27	15
	OC	10.82	21	49
	EC	2.75	5	33
	$PM_{2.5}$	0.9	2	22
	PM_{10}	4.82	10	25
	Sea Salt	0.07	0	
Washakie WA	Sulfate	4.87	21	7
	Nitrate	1.61	7	16
	OC	11.64	49	15
	EC	1.86	8	15
	$PM_{2.5}$	0.85	4	45
	PM_{10}	2.91	12	56
	Sea Salt	0.01	0	
Wind Cave NP	Sulfate	13.2	32	2
	Nitrate	6.98	17	0
	OC	13.22	32	21
	EC	2.92	7	15
	$PM_{2.5}$	0.85	2	11
	PM_{10}	3.52	9	13
	Sea Salt	0.03	0	

[1] Contribution of sulfate and nitrate based on PSAT; OC, EC, $PM_{2.5}$, PM_{10}, and Sea Salt contribution based on WEP.

4. Visibility Projection Modeling

The Regional Modeling Center (RMC) at the University of California Riverside, under the oversight of the WRAP Modeling Forum, performed modeling for the regional haze LTS for the WRAP member states, including Montana. The modeling analysis is a complex technical evaluation that began with selection of the modeling system. RMC primarily used the Community Multi-Scale Air Quality (CMAQ) photochemical grid model to estimate 2018 visibility conditions in Montana and all western Class I areas, based on application of the regional haze strategies in the various state plans, including some assumed controls on BART sources.

The RMC 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 regional haze 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 2007. All emission inventories were spatially and temporally allocated using the Sparse Matrix Operator Kernel Emissions (SMOKE) modeling system. 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.[210] A more detailed description of the CMAQ modeling performed for the WRAP can be found in the docket.[211]

The photochemical modeling of regional haze 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 RMC 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 regional haze assessment of the LTS and for use in the modeling assessment. The 2002 modeling efforts were used to evaluate air quality/visibility modeling for a historical episode—in this case, for calendar year 2002—to demonstrate the suitability of the modeling systems for subsequent planning, sensitivity, and emissions control strategy modeling. Model performance evaluation 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 RMC determined that model performance was acceptable, it used the model to determine the 2018 RPGs using the current and future year air quality modeling predictions, and compared the RPGs to the URP.

5. Consultation and Emissions Reduction for Other States' Class I Areas

40 CFR 51.308(d)(3)(i) requires that EPA consult with another state if Montana's emissions are reasonably anticipated to contribute to visibility impairment at that state's Class I area(s), and that EPA consult with other states if those other states' emissions are reasonably anticipated to contribute to visibility impairment at Montana's Class I areas. EPA worked with other states and tribes through the WRAP process. EPA also accepts and incorporates the WRAP-developed visibility modeling

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

[211] WRAP TSD and ''Air Quality Modeling,'' available at: *http://vista.cira.colostate.edu/docs/WRAP/Modeling/AirQualityModeling.doc.*

into the Regional Haze FIP for Montana.[212]

This proposal contains the necessary measures to meet Montana's share of the reasonable progress goals for the other state's Class I areas.

Table 149 above shows Montana's contribution to Class I areas in neighboring states. None of the neighboring states with Class I areas have indicated to EPA that specific reductions are necessary for this FIP. Therefore, EPA proposes that this FIP meets Montana's share of the reasonable progress goals for the other state's Class I areas.

6. EPA's Reasonable Progress Goals for Montana

In order to establish RPGs for the Class I areas in Montana and to determine the controls needed for the LTS, we followed the process established in the Regional Haze Rule. First, we identified the anticipated visibility improvement in 2018 in all Montana Class I areas accounting for all existing enforceable federal and state regulations already in place and anticipated BART controls. The WRAP CMAQ modeling results were used to identify the extent of visibility improvement from the baseline by pollutant for each Class I area.

a. EPA's Use of WRAP Visibility Modeling

We are relying on modeling performed by WRAP. The primary tool WRAP relied upon for modeling regional haze improvements by 2018, and for estimating Montana's RPGs, was the CMAQ model. The CMAQ model was used to estimate 2018 visibility conditions in Montana and all western Class I areas, based on application of anticipated regional haze strategies in the various states' regional haze plans, including assumed controls on BART sources.

The RMC at the University of California Riverside conducted the CMAQ modeling under the oversight of the WRAP Modeling Forum. The RMC 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 regional haze 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 2007. A more detailed description of the inventories can be found in the following documents that are included in the docket.[213] All emission inventories were spatially and temporally allocated using the SMOKE modeling system. Each of these inventories underwent a number of revisions throughout the development process to arrive at the final versions used in CMAQ modeling.[214]

b. EPA's Reasonable Progress ''Four-Factor'' Analysis

In determining the measures necessary to make reasonable progress and in selecting RPGs for mandatory Class I areas within Montana, we must take into account the following four factors and demonstrate how they were taken into consideration:

- 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 51.308(d)(1)(i)(A).

As the purpose of the reasonable progress analysis is to evaluate the potential of controlling certain sources or source categories for addressing visibility from manmade sources, our four-factor analysis addresses only anthropogenic sources, on the assumption that the focus should be on sources that can be ''controlled.''

As explained previously, WRAP developed emission inventories for 11 source categories and we are proposing to use this analysis to identify sources that should be evaluated for further control. Specifically, we identified those source categories that, based on the inventories, contribute the most to emissions of visibility impairing pollutants and for which there are not adequate controls. The visibility impairing pollutants we considered are primary organic aerosol, EC, $PM_{2.5}$, PM_{10}, SO_2, and NO_X.

Tables 150 through 154 provide the statewide 2002 baseline primary organic aerosol, EC, $PM_{2.5}$ and PM_{10} emissions and percentage contribution from the eleven source categories evaluated by WRAP.

TABLE 150—MONTANA PRIMARY ORGANIC AEROSOL EMISSION INVENTORY—2002

Source category	Baseline 2002 (tpy)	Percentage of total
Point	101	<1
Anthropogenic Fire	3,745	8
Natural Fire	38,324	80
Biogenic	0	0
Area	2,788	6
Area Oil and Gas	0	0
On-Road Mobile	455	1
Off-Road Mobile	718	2
Road Dust	1,271	3
Fugitive Dust	687	1
Wind Blown Dust	0	0
Total	48,089	

[212] See ''Air Quality Modeling,'' available at: *http://vista.cira.colostate.edu/docs/WRAP/Modeling/AirQualityModeling.doc.*

[213] WRAP TSD; WRAP PRP 18b Emissions Inventory—Revised Point and Area Sources Projections, Final dated October 16, 2009; Development of 2000–04 Baseline period and 2018 Projection Year Emission Inventories, Final, dated May 2007; Final Report, WRAP Mobile Source Emission Inventories Updated, dated May 2006; Emissions Overview, for which WRAP did not include a date; 2002 Planning Simulation Version D Specification Sheet for which WRAP did not include a date; 2018 Preliminary Reasonable Progress Simulation Version B Specification Sheet for which WRAP did not include a date. The actual inventories can be found in the docket in the spreadsheets with the following titles: 02d Point Source Inventory; 02d Area Source Inventory; PRP18b Point Source Inventory; PRP 18b Area Source Inventory.

[214] A more detailed description of the CMAQ modeling performed by WRAP can be found in WRAP's TSD dated February 29, 2011, and also in the document in the docket titled Air Quality Modeling for which the WRAP did not include a date.

TABLE 151—MONTANA ELEMENTAL CARBON EMISSION INVENTORY—2002

Source category	Baseline 2002 (tpy)	Percentage of total
Point	17	<1
Anthropogenic Fire	759	6
Natural Fire	7,743	65
Biogenic	0	0
Area	413	3
Area Oil and Gas	0	0
On-Road Mobile	519	4
Off-Road Mobile	2,288	19
Road Dust	89	<1
Fugitive Dust	47	<1
Wind Blown Dust	0	0
Total	11,873	....

TABLE 152—MONTANA FINE PARTICULATE MATTER EMISSION INVENTORY—2002

Source category	Baseline 2002 (tpy)	Percentage of total
Point	182	<1
Anthropogenic Fire	279	<1
Natural Fire	2,911	4
Biogenic	0	0
Area	2,472	3
Area Oil and Gas	0	0
On-Road Mobile	0	0
Off-Road Mobile	0	0
Road Dust	21,671	28
Fugitive Dust	13,276	17
Wind Blown Dust	36,448	47
Total	77,239	....

TABLE 153—MONTANA COARSE PARTICULATE MATTER EMISSION INVENTORY—2002

Source category	Baseline 2002 (tpy)	Percentage of total
Point	7,818	1
Anthropogenic Fire	713	<1
Natural Fire	8,496	1
Biogenic	0	0
Area	706	<1
Area Oil and Gas	0	0
On-Road Mobile	270	<1
Off-Road Mobile	0	0
Road Dust	206,863	33
Fugitive Dust	68,373	11
Wind Blown Dust	328,036	53
Total	621,276	....

As indicated, point sources contribute less than 1% to primary organic aerosol emissions, less than 1% to EC emissions, less than 1% to fine particulate, and 1% to coarse particulate emissions. Also, BART modeling that we conducted tends to indicate that PM emissions from point sources have the potential to contribute only a minimal amount to the visibility impairment in the Montana Class I areas. Since the contribution from point sources to primary organic aerosols, EC, $PM_{2.5}$ and PM_{10} is very small, and modeling tends to show that PM emissions from point sources do not have a very large impact, we are proposing that additional controls on point sources for primary organic aerosols, EC, $PM_{2.5}$ and PM_{10} are not necessary for this planning period. We next consider other sources of these pollutants.

Anthropogenic fire contributes 8% to primary organic aerosol emissions, 6% to EC emissions, less than 1% to $PM_{2.5}$ emissions and less than 1% to PM_{10} emissions. Anthropogenic fire emissions are controlled through Montana's visibility SIP, which we propose for approval as addressing one of the required LTS factors, Agricultural and Forestry Smoke Management Techniques, in section V.D.6.f.v . Natural fire contributes 80% to primary organic aerosol emissions, 65% to EC emissions, 4% to $PM_{2.5}$ emissions, and 1% to PM_{10} emissions. Natural fires are considered uncontrollable. In summary, we are proposing that additional controls for primary organic aerosols, EC, $PM_{2.5}$ and PM_{10} from anthropogenic fire are not necessary for this planning period. We also are proposing that natural fires do not need to be addressed because they are not man-made.

Area sources contribute only 6% to primary organic aerosol emissions, 3% to EC emissions, 3% to $PM_{2.5}$ emissions, and less than 1% to PM_{10} emissions. We are proposing that because area sources have such a small contribution to the emissions inventory, additional controls for primary organic aerosols, EC, $PM_{2.5}$ and PM_{10} from area sources are not necessary for this planning period.

On-road mobile sources contribute only 1% to primary organic aerosol emissions, 4% to EC emissions, and less than 1% to PM_{10} emissions. Off-road mobile sources contribute 2% to primary organic aerosol emissions and 19% to EC emissions. Both on-road and off-road mobile sources will benefit from fleet turnover to cleaner vehicles resulting from more stringent federal emission standards. Since emissions are expected to decrease as newer vehicles replace older ones, we are proposing that additional controls for primary organic aerosols, EC, $PM_{2.5}$ and PM_{10} from on-road and off-road vehicles are not necessary during this planning period.

Emissions from road dust contribute 3% to primary organic aerosol emissions, less than 1% to EC emissions, 28% to $PM_{2.5}$ emissions and 33% to PM_{10} emissions. Wind-blown dust contributes 47% to fine particulate emissions and 53% to PM_{10} emissions. Road dust and wind-blown dust are regulated by the State's ARM 17.8.308, Particulate Matter, Airborne. This regulation, which is approved into Montana's SIP, establishes an opacity limit of 20% and also requires reasonable precautions to be taken to control emissions of airborne PM from the production, handling, transportation, or storage of any material. It also requires reasonable precautions to be taken to control emissions of airborne PM from streets, roads, and parking lots. In addition, in any nonattainment area, this regulation requires Reasonable Available Control Technology for existing sources, BACT for new sources with a potential to emit less than 100 tpy, and Lowest Achievable Emission Rates for new sources that have the potential to emit more than 100 tpy. Finally, this regulation requires operators of a construction site to take reasonable precautions to control emissions of airborne PM at construction and demolition sites and it establishes a 20% opacity limit for emissions of airborne pollutants at these sites. The measures to mitigate the impact of construction activities are included as one of the required LTS factors in section V.D.6.f.ii. We are proposing that the existing rules at ARM 17.8.308 are sufficient to control emissions of OC, EC, $PM_{2.5}$ and PM_{10} and that additional controls for primary organic aerosols, EC, $PM_{2.5}$ and PM_{10} from road dust, fugitive dust, and windblown dust are not necessary for this planning period.

Table 154 provides the Statewide baseline SO_2 emissions and percentage contribution to the total SO_2 emissions in Montana.

TABLE 154—MONTANA SO_2 EMISSION INVENTORY—2002

Source category	Baseline 2002 (tpy)	Percentage of total
Point	36,887	71
Anthropogenic Fire	500	1
Natural Fire	4,634	9
Biogenic	0	0
Area	3,236	6
Area Oil and Gas	225	<1
On-Road Mobile	1,836	4
Off-Road Mobile	4,552	9
Road Dust	11	<1
Fugitive Dust	13	<1
Wind Blown Dust	0	0
Total	51,923	

As indicated, 71% of total Statewide SO_2 emissions are from point sources, 6% are from area sources and less than 1% are from area oil and gas sources. Emissions from anthropogenic fire contribute 1% and emissions from natural fire contribute 9% to Statewide SO_2 emissions. Anthropogenic fire emissions are controlled through Montana's Visibility SIP, which is further described as one of the required LTS factors, Agricultural and Forestry Smoke Management Techniques, in V.D.6.f.v. SO_2 emissions from natural fires (9%) are considered uncontrollable. On-road mobile sources contribute 4% and off-road sources contribute 9% to Statewide SO_2 emissions. Both off-road and on-road mobile sources are subject to federal ultra-low sulfur diesel fuel requirements that limit sulfur content to 15 ppm (0.0015%), which was in widespread use after June 2010 for off-road mobile and June 2006 for on-road mobile. Road dust, fugitive dust and windblown dust comprise less than 1% of Statewide emissions. We are proposing that point sources are the dominant source of emissions and, for this planning period, the only category necessary to evaluate further under reasonable progress for SO_2.

Table 155 provides the Statewide baseline NO_X emissions and percentage contribution to the total NO_X emissions in Montana.

TABLE 155—MONTANA NO_X EMISSION INVENTORY—2002

Source category	Baseline 2002 (tpy)	Percentage of total
Point	53,416	22
Anthropogenic Fire	1,513	<1
Natural Fire	13,770	6

TABLE 155—MONTANA NO_X EMISSION INVENTORY—2002—Continued

Source category	Baseline 2002 (tpy)	Percentage of total
Biogenic	58,353	24
Area	4,292	2
Area Oil and Gas	7,557	3
On-Road Mobile	53,597	22
Off-Road Mobile	50,604	21
Road Dust	25	<1
Fugitive Dust	14	<1
Wind Blown Dust	0	0
Total	24,314	

As indicated, 22% of total Statewide NO_X emissions are from point sources. Emissions from anthropogenic fire contribute less than 1% and emissions from natural fire contribute 6% to Statewide NO_X emissions. Agricultural and Forestry smoke management techniques are discussed in section V.D.6.f.v as one of the mandatory LTS factors required to be considered. Emissions from natural fires are considered uncontrollable. Emissions from biogenic sources contribute 24% and also are considered uncontrollable. Emissions from area sources contribute only 2% and emissions from area oil and gas sources contribute only 3% of statewide emissions. Emissions from on-road mobile sources contribute 22% and emissions from off-road mobile sources contribute 21% to Statewide NO_X emissions. Both on-road and off-road mobile sources will benefit from fleet turnover to cleaner vehicles resulting from more stringent federal emission standards. We are proposing that point sources are the dominant source of emissions not already being addressed and, for this planning period, the only category necessary to evaluate further under reasonable progress for NO_X.

To identify the point sources in Montana that potentially affect visibility in Class I areas, we started with the list of sources included in the 2002 NEI, except that for Colstrip Units 3 and 4 we used data from 2010. For Colstrip, we included only the emissions for Units 3 and 4 because Units 1 and 2 are subject to BART. Also, a consent decree signed in 2007 required upgraded combustion controls on Units 3 and 4. The year 2010 was the first full year that the upgraded combustions controls were operational for both units.

We divided the actual emissions (Q) in tpy from each source in the inventory by their distance (D) in kilometers to the nearest Class I Federal area. We are proposing to use a Q/D value of 10 as our threshold for further evaluation for RP controls. We chose this value based on the FLMs' Air Quality Related Values Work Group guidance amendments for initial screening criteria, as well as statements in EPA's BART Guidelines.[215] A comprehensive list of the sources we reviewed is included in the docket as a spreadsheet titled, ''Montana Q Over D Analysis.'' The sources with Q/D results greater than 10 are listed below in Table 156.

TABLE 156—MONTANA Q/D ANALYSIS SOURCES WITH RESULTS GREATER THAN 10

Source	SO_2 + NO_X emissions (tons)	Distance to nearest class I area (km)	Q/D (tons/km)
PPL Montana, LLC Colstrip Steam Electric Station (Units 3 and 4)	15,754	193	82
Plum Creek Manufacturing	1,067	13	82
Ash Grove Cement Company	2,060	31	66
Columbia Falls Aluminum Company, LLC	591	10	59
ExxonMobil Refinery & Supply Company, Billings Refinery	6,313	161	39
PPL Montana, LLC—JE Corette Steam Electric Station	4,838	136	36
Smurfit Stone Container Enterprises Inc., Missoula Mill	1,315	41	32
Montana-Dakota Utilities Company Lewis and Clark Station	1,576	54	29
Cenex Harvest States Cooperatives Laurel Refinery	3,038	161	19
Holcim (US), Inc.	1,783	97	18
Montana Sulphur and Chemical	2,408	161	15
Yellowstone Energy Limited Partnership	1,928	141	14
Roseburg Forest Products	518	44	12
Devon Energy Production Company, LP, Blaine County #1 Compressor Station	1,155	107	11
Colstrip Energy Limited Partnership	1,242	117	11
Montana Refining	774	77	10
Conoco Phillips	1,323	136	10

[215] The relevant language in our BART Guidelines reads, ''Based on our analyses, we believe that a State that has established 0.5 deciviews as a contribution threshold could reasonably exempt from the BART review process sources that emit less than 500 tpy of NO_X or SO_2 (or combined NO_X and SO_2), as long as these sources are located more than 50 kilometers from any Class I area; and sources that emit less than 1000 tpy of NO_X or SO_2 (or combined NO_X and SO_2) that are located more than 100 kilometers from any Class I area.'' (See 40 CFR part 51, appendix Y, section III, How to Identify Sources ''Subject to BART.'') The values described equate to a Q/D of 10.

For the reasons described below, we eliminated from further consideration several sources that met the Q/D criteria.

We are eliminating the four refineries from further consideration as a result of consent decrees entered into by the owners. Under these consent decrees, emissions have been reduced sufficiently after the 2002 baseline so that the Q/D for each facility is below 10. Specifically, ExxonMobil's emissions in 2008 of NO_X and SO_2 were 1,019 tpy, resulting in a Q/D of 6. Cenex's emissions in 2008 of NO_X and SO_2 were 727 tpy, resulting in a Q/D of 5. Conoco's emissions in 2008 of NO_X and SO_2 were 1,087 tpy, resulting in a Q/D of 8. Montana Refining's emissions in 2008 of NO_X and SO_2 were 122 tpy, resulting in a Q/D of 2. The consent decrees are available in the docket.

We eliminated from further discussion the following sources because they were evaluated under BART: Colstrip Units 1 and 2, Ash Grove Cement, CFAC, PPL Montana JE Corette, and Holcim US Incorporated, Trident Plant. As the BART analysis is based, in part, on an assessment of many of the same factors that are addressed under RP or RPGs, we propose that the BART control requirements for these facilities also satisfy the requirements for reasonable progress for the facilities for this planning period.

We undertook a more detailed analysis of the remaining sources that exceeded a Q/D of 10. These sources are shown below in Table 157.

TABLE 157—SOURCES FOR REASONABLE PROGRESS FOUR-FACTOR ANALYSES

Source	SO_2 + NO_X Emissions (tons)	Distance to nearest class I area (km)	Q/D (tons/km)
PPL Montana, LLC Colstrip Steam Electric Station (Units 3 and 4)	15,754	193	82
Plum Creek Manufacturing	1,067	13	82
Smurfit Stone Container Enterprises Inc., Missoula Mill	1,315	41	32
Montana Dakota Utilities Company Lewis and Clark Station	1,576	54	29
Montana Sulphur and Chemical	2,408	161	15
Yellowstone Energy Limited Partnership	1,928	141	14
Roseburg Forest Products	518	44	12
Devon Energy Production Company, LP Blaine County #1 Compressor Station	1,155	107	11
Colstrip Energy Limited Partnership	1,242	117	11

c. Four Factor Analyses for Point Sources

The BART Guidelines recommend that states utilize a five-step process for determining BART for sources that meet specific criteria. In proposing a FIP we are considering this recommendation applicable to us as it would be applicable to a state. Although this five-step process is not required for making RP determinations, we have elected to largely follow it in our RP analysis because there is some overlap in the statutory BART and RP factors and because it provides a reasonable structure for evaluating potential control options.

We requested a four factor analysis from each RP source and our analysis has taken that information into consideration.

i. Colstrip Energy Limited Partnership

Colstrip Energy Limited Partnership (CELP) submitted analysis and supporting information on March 11, 2009 and February 24, 2011.[216]

CELP in partnership with Rosebud Energy Corporation, owns the Rosebud Power Plant, operated by Rosebud Operating Services. The plant is rated at 43 MWs gross output (38 MWs net). The primary source of emissions consists of a single circulating fluidized bed (CFB) boiler, fired on waste coal. The boiler and emission controls were installed in 1989–90.

PM emissions are controlled by a fabric filter baghouse that is designed to achieve greater than 99% control of particulates.[217] As discussed previously in Section V.D.6.b., the contribution from point sources to primary organic aerosols, EC, $PM_{2.5}$ and PM_{10} at Montana Class I areas is very small, and modeling tends to confirm that PM emissions from point sources do not have a very large impact. Therefore, we are proposing that additional controls for PM are not necessary for this planning period.

SO_2

The current SO_2 control consists of limestone injection with waste coal prior to its combustion in the boiler.

Step 1: Identify All Available Technologies

We identified that the following technologies are available: limestone injection process upgrade, SDA, DSI, a circulating dry scrubber (CDS), hydrated ash reinjection (HAR), a wet lime scrubber, a wet limestone scrubber, and/or a dual alkali scrubber.

CELP currently controls SO_2 emissions using limestone injection. Crushed limestone is injected with the waste coal prior to its combustion in the boiler, becoming the solid medium in which coal combustion takes place. When limestone is heated to 1550°F, it releases CO_2 and forms lime, which subsequently reacts with acid gases released from the burning coal, to form calcium sulfates and calcium sulfites. The calcium compounds are removed as PM by the baghouse. Depending on the fuel fired in the boiler and the total heat input, this process currently removes 70% to 90% of SO_2 emissions, on average about 80%. Increasing the limestone injection rate beyond current levels could theoretically result in a modest increase in SO_2 control.[218]

SDAs use lime slurry and water injected into a tower to remove SO_2 from the combustion gases. The towers must be designed to provide adequate contact and residence time between the exhaust gas and the slurry in order to produce a relatively dry by-product. The process equipment associated with an SDA typically includes an alkaline storage tank, mixing and feed tanks, atomizer, spray chamber, particulate

[216] Response to Request for Information for the Colstrip Energy Limited Partnership Facility Pursuant to Section 114(a) of the Clean Air Act (42 U.S.C. Section 7414(A) (''CELP Initial Response''), Rosebud Energy Corp. (Mar. 11, 2009); Response to Additional Reasonable Progress Information for the Colstrip Energy Limited Partnership Facility Pursuant to Section 114(a) of the Clean Air Act (42 U.S.C. Section 7414(A)) (''CELP Additional Response''), Rosebud Energy Corp., Prepared by Bison Engineering Inc (Feb. 24, 2011).

[217] CELP Additional Response, p. 2–1.

[218] CELP Additional Response, p. 2–2.

control device, and recycle system. The recycle system collects solid reaction product and recycles it back to the spray dryer feed system to reduce alkaline sorbent use. SDAs are the commonly used dry scrubbing method in large industrial and utility boiler applications. SDAs have demonstrated the ability to achieve 90% to 94% SO_2 reduction. SDA plus limestone injection can achieve between 98% and 99% SO_2 reduction.[219]

DSI was previously described in our evaluation for Corette. SO_2 control efficiencies for DSI systems by themselves (not downstream of limestone injection systems) are approximately 50%, but if the sorbent is hydrated lime, then 80% or greater removal can be achieved. These systems are commonly called lime spray dryers.

A CDS uses a fluidized bed of dry hydrated lime reagent to remove SO_2. Flue gas passes through a venturi at the base of a vertical reactor tower and is humidified by a water mist. The humidified flue gas then enters a fluidized bed of powdered hydrated lime where SO_2 is removed. The dry by-product produced by this system is routed with the flue gas to the particulate removal system. A CDS can achieve removal efficiency similar to that achieved by SDA on CFB boilers.[220]

The HAR process is a modified dry FGD process developed to increase the use of unreacted lime in the CFB ash and any free lime left from the furnace burning process. HAR will further reduce the SO_2 concentration in the flue gas. The actual design of an HAR system is vendor-specific, but in general, a portion of the collected ash and lime is hydrated and re-introduced into a reaction vessel located ahead of the fabric filter inlet. In conventional boiler applications, additional lime may be added to the ash to increase the mixture's alkalinity. For CFB applications, sufficient residual lime is available in the ash and additional lime is not required. HAR downstream of a CFB boiler that utilizes limestone injection can reduce the remaining SO_2 by about 80%.[221]

The wet lime scrubbing process uses alkaline slurry made by adding CaO to water. The alkaline slurry is sprayed into the exhaust stream and reacts with the SO_2 in the flue gas. Insoluble calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) salts are formed in the chemical reaction that occurs in the scrubber. The salts are removed as a solid waste by-product.

Wet lime and wet limestone scrubbers involve spraying alkaline slurry into the exhaust gas to react with SO_2 in the flue gas. The reaction in the scrubber forms insoluble salts that are removed as a solid waste by-product. Wet lime and limestone scrubbers are very similar, but the type of additive used differs (lime or limestone). Using limestone ($CaCO_3$) instead of lime requires different feed preparation equipment and a higher liquid-to-gas ratio. The higher liquid-to-gas ratio typically requires a larger absorbing unit. The limestone slurry process also requires a ball mill to crush the limestone feed. Wet lime and limestone scrubbers have been demonstrated to achieve greater than 99% control efficiency.[222]

Dual-alkali scrubbers use a sodium-based alkali solution to remove SO_2 from the combustion exhaust gas. The process uses both sodium-based and calcium-based compounds. The sodium-based reagents absorb SO_2 from the exhaust gas, and the calcium-based solution (lime or limestone) regenerates the spent liquor. Calcium sulfites and sulfates are precipitated and discarded as sludge, and the regenerated sodium solution is returned to the absorber loop. The dual-alkali process requires lower liquid-to-gas ratios than scrubbing with lime or limestone. The reduced liquid-to-gas ratios generally mean smaller reaction units; however, additional regeneration and sludge processing equipment is necessary.

A sodium-based scrubbing solution, typically consisting of a mixture of sodium hydroxide, sodium carbonates, and sodium sulfite, is an efficient SO_2 control reagent. However, the process generates a sludge that can create material handling and disposal issues. The control efficiency is similar to the wet lime/limestone scrubbers at approximately 95% or greater.

Step 2: Eliminate Technically Infeasible Options

The current limestone injection system is operating at or near its maximum capacity. The boiler feed rates are approximately 770 tons/day of waste coal and 91 tons/day of limestone. Increasing limestone injection beyond the current levels would result in plugging of the injection lines, and increased bed ash production, which can reduce combustion efficiency, and increased particulate loading to the baghouses. Therefore, increasing limestone injection beyond its current level would require major upgrades to the limestone feeding system and the baghouses.[223] Only modest increases in SO_2 removal efficiency, if any, are expected with this scenario, compared to add-on SO_2 control systems discussed below. Therefore, a limestone injection process upgrade is eliminated from further consideration.

CDS systems result in high particulate loading to the unit's particulate control device. Because of the high particulate loading, the pressure drop across a fabric filter would be unacceptable; therefore, ESPs are generally used for particulate control. CELP has a high efficiency fabric filter (baghouse) in place. Based on limited technical data from non-comparable applications and engineering judgment, we are determining that CDS is not technically feasible for this baghouse-equipped facility.[224] Therefore, CDS is eliminated from further consideration.

A DSI system is not practical for use in a CFB boiler such as CELP, where limestone injection is already being used upstream in the boiler for SO_2 control. With limestone injection, the CFB boiler flue gas already contains excess unreacted lime. Fly ash containing this unreacted lime is reinjected back into the CFB boiler combustion bed, as part of the boiler operating design. A DSI system would simply add additional unreacted lime to the flue gas and would achieve little, if any, additional SO_2 control.[225] If used instead of limestone injection (the only practical way it might be used), DSI would achieve less control efficiency (50%) than the limestone injection system already being used (70% to 90%). Therefore, DSI is eliminated from further consideration.

Regarding wet scrubbing, there is limited area to install additional SO_2 controls that would require high quantities of water and dewatering ponds. The wet FGD scrubber systems with the higher water requirements (wet lime scrubber, wet limestone scrubber, dual alkali wet scrubber) would require an on-site dewatering pond or an additional landfill to dispose of scrubber sludge. Due to the limited available space, its proximity to the East Armels Creek to the east of the plant, an unnamed creek to the south of the plant, and limited water availability for these

[219] US EPA Region 8, Final Statement of Basis, PSD Permit to Construct, Deseret Power Elec. Coop., Bonanza Power Plant (''Deseret Bonanza SOB''), p. 92 (Aug. 30, 2007), available at *http://www.epa.gov/region8/air/pdf/FinalStatementOfBasis.pdf*.

[220] *Id.*

[221] *Id.*, p. 93.

[222] *Id.*, p. 94 (for proposed CFB boiler, indicating that a wet FGD scrubber plus limestone injection can achieve 99.1% control efficiency).

[223] CELP Additional Response, p. 2–2.

[224] Deseret Bonanza SOB, p. 92 (indicating that CDS systems have thus far not been used on CFB boilers).

[225] Id., p. 93.

controls,[226] we consider these technologies technically infeasible and do not evaluate them further.

The remaining technically feasible SO_2 control options for CELP are SDA and HAR.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

Baseline SO_2 emissions from CELP are 1141 tpy. A summary of emissions projections for the various control options is provided in Table 158. Since limestone injection is already in use at the CELP facility, the control efficiencies and emissions reductions shown below are those that might be achieved beyond the control already being achieved by the existing limestone injection system.

TABLE 158—SUMMARY OF CELP SO_2 REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGIES

Control option	Control effectiveness (%)	Emissions reduction tpy	Remaining emissions tpy
SDA	80	913	228
HAR	50	571	570

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

Table 159 provides a summary of estimated annual costs for the various control options.

TABLE 159—SUMMARY OF CELP SO_2 REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
SDA with baghouse replacement	4,419,472	4,840
SDA without baghouse replacement	3,138,450	3,437
HAR with baghouse replacement	3,384,565	5,927
HAR without baghouse replacement	2,103,543	3,684

We are relying on the control costs provided by CELP,[227] with two exceptions. First, we calculated the annual cost of capital using a 7% annual interest rate and a 20-year equipment life (which yields a capital CRF of 0.0944), as specified in the Office of Management and Budget's Circular A–4, Regulatory Analysis.[228] Second, we calculated the cost of SDA and HAR in two ways: (1) With baghouse replacement, and (2) without baghouse replacement.

Factor 2: Time Necessary for Compliance

We have relied on CELP's estimates that the time necessary to complete the modifications to the boiler to accommodate SDA or HAR, without baghouse replacement, would be approximately four to six months and that a boiler outage of approximate two to three months would be necessary to perform the installation of either system. As noted previously, CELP states that complete replacement or major modifications to the existing baghouse would be necessary; however, the company does not explain why the existing baghouse would need to be replaced or modified to accommodate SDA or HAR.[229]

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

Wet FGD systems are estimated to consume 1% to 2.5% of the total electric generation of the plant and can consume approximately 40% more than dry FGD systems (SDA). Electricity requirements for a HAR system are less than FGD systems. DSI systems are estimated to consume 0.1% to 0.5% of the total plant generation.[230] For reasons explained above, wet FGD systems and DSI systems have already been eliminated as technically infeasible.

SO_2 controls would result in increased ash production at the CELP facility. Boiler ash is currently either sent to a landfill or sold for beneficial use, such as oil well reclamation. Changes in ash properties due to increased calcium sulfates and calcium sulfites could result in the ash being no longer suitable to be sold for beneficial uses. If the ash properties were to change such that the ash could no longer be sold for beneficial use, the loss of this market would cost approximately $1,020,000 per year at the current ash value and production rates (approximately 100,000 tons of ash per year). The loss of this market could also result in the company having to dispose of the ash at its current landfill, which is adjacent to the plant. The cost to dispose of the ash would be approximately $62,000 per year. The total cost from the loss of the beneficial use market and the increase in ash disposal costs would be a total of $1,082,000 per year.[231] This potential cost has not been included in the cost described above, as it is only speculative, being based on an undetermined potential future change in ash properties.

As described above, wet FGD scrubber systems with the higher water requirements (wet lime scrubber, wet limestone scrubber, dual alkali wet scrubber) would require an on-site dewatering pond or an additional landfill to dispose of scrubber sludge.

[226] CELP Additional Response, p. 2–5.

[227] CELP Additional Response, Appendix A, pp. 17–24.

[228] Available at: *http://www.whitehouse.gov/omb/circulars_a004_a-4/.*

[229] CELP Additional Response, p. 3–1.

[230] *Id.,* p. 4–1.

[231] *Id.*

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: the cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the source. We are also taking into account the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. Given the cost of $3,437 per ton of SO_2 (at a minimum) for the most cost-effective option (SDA), the relatively small size of CELP, and the small baseline Q/D of 11, we find it reasonable to not impose any of the SO_2 control options. We therefore propose to not require additional SO_2 controls for this planning period.

NO_X

Currently, there are no NO_X controls at the CELP facility.

Step 1: Identify All Available Technologies

We identified that the following technologies to be available: SCR, SNCR, low excess air (LEA), FGR, OFA, LNB, non-thermal plasma reactor, and carbon injection into the combustion chamber.

SCR uses either NH_3 or urea in the presence of a metal-based catalyst to selectively reduce NO_X emissions. Technical factors that impact the effectiveness of SCR include the catalyst reactor design, operating temperature, type of fuel fired, sulfur content of the fuel, design of the NH_3 injection system, and the potential for catalyst poisoning.

SCR has been demonstrated to achieve high levels of NO_X reduction in the range of 80% to 90% control, for a wide range of industrial combustion sources, including PC and stoker coal-fired boilers and natural gas-fired boilers and turbines. Typically, installation of the SCR is upstream of the particulate control device (e.g., baghouse). However, calcium oxide (from a dry scrubber) in the exhaust stream can cause the SCR catalyst to plug and foul, which would lead to an ineffective catalyst.

SCRs are classified as low dust SCR (LDSCR) or high dust SCR (HDSCR). LDSCR is usually applied to natural gas combustion units or after a particulate control device. HDSCR units can be installed on solid fuel combustion units before the particulate control device, but they have their limitations. Installation of SCR in a low dust flue gas stream is often not practical, especially on an existing boiler. The reason is that the low dust portion of a flue gas stream is located after a baghouse or precipitator. The temperature of the flue gas stream is too low in these areas for proper operation of SCR. The temperature range for proper operation of SCR is between 480 °F and 800 °F. Many of the CFBs in the United States have baghouses for particulate control. The normal maximum allowable temperature for a baghouse is 400 °F.

Therefore, on some installations, regenerative SCR (RSCR) is installed. RSCRs are expensive to install and expensive to operate, because an RSCR requires the use of burners to heat up the flue gas stream in order for the NO_X capture to occur. This is often an efficiency decrease for the boiler, significant increase in operating cost, and often not a practical solution. For this reason, RSCR was not evaluated as a control option for CELP. Instead, HDSCR was evaluated.

In SNCR systems, a reagent such as NH_3 or urea is injected into the flue gas at a suitable temperature zone, typically in the range of 1,600 to 2,000 °F and at an appropriate ratio of reagent to NO_X.

LEA operation involves lowering the amount of combustion air to the minimum level compatible with efficient and complete combustion. Limiting the amount of air fed to the furnace reduces the availability of oxygen for the formation of fuel NO_X and lowers the peak flame temperature, which inhibits thermal NO_X formation. Emissions reductions achieved by LEA are limited by the need to have sufficient oxygen present for flame stability and to ensure complete combustion. As excess air levels decrease, emissions of carbon monoxide (CO), hydrocarbons (HC) and unburned carbon increase, resulting in lower boiler efficiency. Other impediments to LEA operation are the possibility of increased corrosion and slagging in the upper boiler because of the reducing atmosphere created at low oxygen levels.

FGR is a flame-quenching technique that involves recirculating a portion of the flue gas from the economizers or the air heater outlet and returning it to the furnace through the burner or windbox. The primary effect of FGR is to reduce the peak flame temperature through absorption of the combustion heat by relatively cooler flue gas. FGR also serves to reduce the oxygen concentration in the combustion zone.

OFA allows staged combustion by supplying less than the stoichiometric amount of air theoretically required for complete combustion through the burners. The remaining necessary combustion air is injected into the furnace through overfire air ports. Having an oxygen-deficient primary combustion zone in the furnace lowers the formation of fuel NO_X. In this atmosphere, most of the fuel nitrogen compounds are driven into the gas phase. Having combustion occur over a larger portion of the furnace lowers peak flame temperatures. Use of a cooler, less intense flame limits thermal NO_X formation.

Poorly controlled OFA may result in increased CO and hydrocarbon emissions, as well as unburned carbon in the fly ash. These products of incomplete combustion result from a decrease in boiler efficiency. OFA may also lead to reducing conditions in the lower furnace that in turn may lead to corrosion of the boiler.

LNBs use stepwise or staged combustion and localized exhaust gas recirculation (i.e., at the flame).

The non-thermal plasma technique involves using methane and hexane as reducing agents. Non-thermal plasma is shown to remove NO_X in a laboratory setting with a reactor duct only two feet long. The reducing agents were ionized by a transient high voltage that created a non-thermal plasma. The ionized reducing agents reacted with NO_X achieving a 94% destruction efficiency, and there are indications that an even higher destruction efficiency can be achieved. A successful commercial vendor uses NH_3 as a reducing agent to react with NO_X in an electron beam generated plasma.[232] Such a short reactor can meet available space requirements for virtually any plant. The non-thermal plasma reactor can also be used without a reducing agent to generate ozone and use that ozone to raise the valence of nitrogen for subsequent absorption as nitric acid. This control technology may have practical potential for application to coal-fired CFB boilers as a technology transfer option.

A version of sorbent injection uses carbon injected into the air flow to finish the capture of NO_X. The carbon is captured in either the baghouse or the ESP, just like other sorbents.[233]

[232] Deseret Bonanza SOB, p. 46.

[233] US EPA, Office of Air Quality Planning and Standards, Technical Bulletin: Nitrogen Oxides (NO_X), Why and How They Are Controlled, EPA–456/F–99–006R, p. 19 (Nov. 1999), available at *http://www.epa.gov/ttn/catc/dir1/fnoxdoc.pdf.*

Step 2: Eliminate Technically Infeasible Options

LEA, FGR, and OFA are typically used on Pulverized Coal (PC) units and cannot be used on CFB boilers due to air needed to fluidize the bed.[234] While LEA may have substantial effect on NO_X emissions at PC boilers, it has much less effect on NO_X emissions at combustion sources such as CFBs that operate at low combustion temperatures. FGR reduces NO_X formation by reducing peak flame temperature and is ineffective on combustion sources such as CFBs that already operate at low combustion temperatures. For these reasons, LEA, FGR and OFA are eliminated from further consideration.

LNBs are typically used on PC units and cannot be used on CFB boilers because the combustion occurs within the fluidized bed.[235] CFB boilers do not use burners during normal operation. Therefore, LNBs are eliminated from further consideration.

While a non-thermal plasma reactor may have practical potential for application to coal-fired CFB boilers as a technology transfer option at Step 1 of the analysis, it is not known to be commercially available for CFB boilers.[236] Therefore, a non-thermal plasma reactor is eliminated from further consideration.

Although carbon injection is an emerging technology used to reduce mercury emissions, it has not been used anywhere to control NO_X. Therefore, it is eliminated from further consideration.

The remaining technically feasible NO_X control options for CELP are HDSCR and SNCR.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

Baseline NO_X emissions from CELP are 768 tpy. A summary of emissions projections for the various control options is provided in Table 160.

TABLE 160—SUMMARY OF CELP NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGIES

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions reduction (tpy)
HDSCR	80	614	154
SNCR	50	384	384

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

Table 161 provides a summary of estimated annual costs for the various control options.

TABLE 161—SUMMARY OF CELP NO_X REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
HDSCR	2,102,189	3,423
SNCR	584,717	1,523

We are relying on all the NO_X control costs provided by CELP,[237] with one exception. We calculated the annual cost of capital using a 7% annual interest rate and 20-year equipment life (which yields a capital CRF of 0.0944), as specified in the Office of Management and Budget's Circular A–4, Regulatory Analysis.[238]

Factor 2: Time Necessary for Compliance

We are relaying on CELP's estimates that SCR would take approximately 26 months to install and that SNCR would take 16 to 24 weeks to install.[239]

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

The energy impacts from SNCR are expected to be minimal. SNCR is not expected to cause a loss of power output from the facility. SCR, however, could cause significant backpressure on the boiler, leading to lost boiler efficiency and, thus, a loss of power production. If LDSCR was to be installed instead of HDSCR, CELP would be subject to the additional cost of reheating the exhaust gas.

Regarding other non-air quality environmental impacts of compliance, SCRs can contribute to airheater fouling from the formation of ammonium sulfate. Airheater fouling could reduce unit efficiency, increase flue gas velocities in the airheater, cause corrosion, and erosion. Catalyst replacement can lengthen boiler outages, especially in retrofit installations, where space and access is limited. This is a retrofit installation in a high dust environment, thus fouling is likely, which could lead to unplanned outages or less time between planned outages. On some installations, catalyst life is short and SCRs have fouled in high dust environments. For both SCR and SNCR, the storage of on-site NH_3 could pose a risk from potential releases to the environment. An additional concern is the loss of NH_3, or ''slip'' into the emissions stream from the facility.

[234] CELP Additional Response, pp. 2–7, 2–8.

[235] CELP Additional Response, p. 2–8.

[236] Deseret Bonanza SOB, pp. 46, 48.

[237] CELP Additional Response.

[238] Available at: *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

[239] CELP Additional Response, p. 3–1.

This ''slip'' contributes another pollutant to the environment, which has been implicated as a precursor to $PM_{2.5}$ formation.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: the cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We are also taking into account the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. Based on costs of compliance, the relatively small size of CELP, and the relatively small baseline Q/D, we propose to eliminate the more expensive control option (SCR). The more cost-effective control option (SNCR) would result in a fairly small total reduction in emissions (384 tpy). This would constitute an approximately 20% reduction in overall emissions of SO_2 + NO_X for the facility and a reduction of the facility's Q/D from 11 to 9. Based on the cost of compliance, the relatively small size of CELP, and the reduction in Q/D for SNCR, we find it reasonable to not require SNCR. We therefore propose to not require additional NO_X controls for this planning period.

ii. Colstrip Unit 3

PPL Montana's Colstrip Power Plant (Colstrip), located in Colstrip, Montana, consists of a total of four electric utility steam generating unit; however, only Units 3 and 4 are being analyzed for control options to meet RP requirements under the Regional Haze Rule. All information found within this section is located in the docket. Unit 3, a tangentially fired CE boiler which burns low sulfur, sub-bituminous northern PRB coal, is rated at 805 MW gross output. The boiler started operation in 1984.

PM emissions are controlled by using a wet particulate scrubber that is designed to achieve approximately 99.8% particulate control efficiency.[240] As discussed previously in Section V.D.6.b., the contribution from point sources to primary organic aerosols, EC, $PM_{2.5}$ at Montana Class I areas is very small, and modeling tends to confirm that PM emissions from point sources do not have a very large impact. Therefore, we are proposing that additional controls for PM are not necessary for this planning period.

Colstrip Unit 3 burns low-sulfur (0.7%) coal and has a wet particulate scrubber that achieves 95% SO_2 control. Emissions for the last five years have averaged 0.08 lb/MMBtu. The scrubber has no provisions for bypass and the system includes a spare vessel for the unit which is available for use while servicing the other vessels. Other upgrades to the scrubber are infeasible for the same reasons as described in the BART determinations for Colstrip Units 1 and 2. For these reasons, additional controls for SO_2 will not be considered or required in this planning period. We now consider controls for NO_X.

Currently, Colstrip Unit 3 has installed LNB with SOFA and a Digital Process Control System (DPCS). These controls reduce NO_X emissions by 81%.

Step 1: Identify All Available Technologies

We identified that the following technologies to be available for Colstrip Unit 3: SCR and SNCR. These technologies have been described in the BART determinations for Colstrip Unit 1.

Step 2: Eliminate Technically Infeasible Options

We are not eliminating either SCR or SNCR as technically infeasible. Thus, the technically feasible NO_X control options for Colstrip Unit 3 are SCR and SNCR.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

Baseline NO_X emissions from Colstrip Unit 3 are 5,428 tpy. A summary of emissions projections for the various control options is provided in Table 162.

TABLE 162—SUMMARY OF COLSTRIP UNIT 3 NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGIES

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions reduction (tpy)
SCR	70.2	3,810	1,618
SNCR	25.0	1,356	4,072

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

Refer to the Colstrip Unit 1 section above for general information on how we evaluated the cost of compliance for NO_X controls. EPA's control costs can be found in the docket.

Table 163 provides a summary of estimated annual costs for the various control options.

TABLE 163—SUMMARY OF COLSTRIP UNIT 3 NO_X REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
SCR	17,425,444	4,574
SNCR	3,755,238	2,769

[240] Letter from James Parker to Vanessa Hinkle regarding Request for Additional Reasonable Progress Information—Colstrip Steam Electric Station Units 3 & 4 (''Colstrip 3 & 4 Additional Response''), Attachment 2, p. 2 (Jan. 31, 2011).

We relied on control costs developed for the IPM for direct capital costs for SCR and SNCR.[241] We then used methods provided by the CCM for the remainder of SCR and SNCR calculations. Specifically, we used the methods in the CCM to calculate total capital investment, annual costs associated with operation and maintenance, to annualize the total capital investment using the CRF, and to sum the total annual costs. We used a retrofit factor of ''1,'' reflecting an SCR and SNCR retrofit of typical difficulty in the IPM control costs.

As Colstrip Unit 3 burns sub-bituminous PRB coal having a low sulfur content of 0.91 lb/MMBtu (equating to a SO_2 rate of 1.8 lb/MMBtu),[242] it was not necessary to make allowances in the control costs to account for equipment modifications or additional maintenance associated with fouling due to the formation of ammonium bisulfate. These are only concerns when the rate of SO_2 is above 3 lb/MMBtu.[243] Moreover, ammonium bisulfate formation can be minimized by preventing excessive NH_3 slip. Optimization of the SNCR system can commonly limit NH_3 slip to levels less than the 5 ppm upstream of the pre-air heater.[244] EPA's detailed cost calculations for SNCR can be found in the docket.

For SNCR we used a urea reagent cost estimate of $450 per ton, taken from PPL's September 2011 submittal for Colstrip Units 1 and 2.[245] For SCR, we used an aqueous ammonia (29%) cost of $240 per ton,[246] and a catalyst cost of $6,000 per cubic meter.[247] To estimate the average cost effectiveness (dollars per ton of emissions reductions), we divided the total annual cost by the estimated NO_X emissions reductions.

Factor 2: Time Necessary for Compliance

We estimate that SCR and SNCR can be installed within this planning period.

Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance

An SNCR process reduces the thermal efficiency of a boiler as the reduction reaction uses thermal energy from the boiler.[248] Therefore, additional coal must be burned to make up for the decreases in power generation. Using CCM calculations, we determined the additional coal needed for Unit 3 equates to 176,800 MMBtu/yr. For an SCR, the new ductwork and the reactor's catalyst layers decrease the flue gas pressure. As a result, additional fan power is necessary to maintain the flue gas flow rate through the ductwork. SCR systems require additional electric power to meet fan requirements equivalent to approximately 0.3% of the plant's electric output.[249] Both SCR and SNCR require some minimal additional electricity to service pretreatment and injection equipment, pumps, compressors, and control systems. Note that cost of the additional energy requirements has been included in our calculations.

Non-air quality environmental impacts of SNCR and SCR were described in our BART analysis for Colstrip Unit 1.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Optional Factor: Modeled Visibility Impacts

We conducted modeling for Colstrip Unit 3 as described in section V.C.3.a. Table 164 presents the visibility impacts and benefits of SCR and SNCR at the 98th percentile of daily maxima for each Class I area from 2006 through 2008. Table 165 presents the number of days with impacts greater than 0.5 deciviews for each Class I area from 2006 through 2008.

TABLE 164—DELTA DECIVIEW IMPROVEMENT FOR NO_X CONTROLS ON COLSTRIP UNIT 3

Class I area	Baseline impact (delta deciview)	Improvement from SCR (delta deciview)	Improvement from SNCR (delta deciview)
North Absaroka WA	0.200	0.109	0.036
Theodore Roosevelt NP	0.498	0.273	0.099
UL Bend WA	0.471	0.261	0.084
Washakie WA	0.223	0.105	0.044
Yellowstone NP	0.151	0.063	0.032

TABLE 165—DAYS GREATER THAN 0.5 DECIVIEW FOR NO_X CONTROLS ON COLSTRIP UNIT 3

[Three Year Total]

Class I area	Baseline (days)	Using SCR	Using SNCR
North Absaroka WA	2	0	2
Theodore Roosevelt NP	14	2	8
UL Bend WA	15	0	10
Washakie WA	2	0	2
Yellowstone NP	1	0	1

[241] IPM, Chapter 5, Appendix 5–2A and 5–2B.

[242] U.S. DOE, Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants 1999 Tables, DOE/EIA–0191(99), Table 24 (June 2000).

[243] IPM, Chapter 5, p. 5–9.

[244] ICAC, p. 8.

[245] NO_X Control Update to PPL Montana's Colstrip Generating Station BART Report, September 2011, p. 8.

[246] Email communication with Fuel Tech, Inc. (Mar. 2, 2012).

[247] Cichanowicz 2010, p. 6–7.

[248] CCM, Section 4.2, Chapter 1, p. 1–21.

[249] CCM, Section 4.2, Chapter 2, p. 2–28.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We have also considered an additional factor: The modeled visibility benefits of controls. We evaluated this factor for Colstrip Units 3 and 4, due to the size of Colstrip Units 3 and 4 in comparison with the other RP sources. For the more cost-effective option (SNCR), the modeled visibility benefits are relatively modest. For the more expensive option (SCR), the modeled visibility benefits, although more substantial, are not sufficient for us to consider it reasonable to impose this option in this planning period. Therefore, we are proposing that no additional NO_X controls will be required for this planning period on Colstrip Unit 3.

iii. Colstrip Unit 4

All information found within this section is located in the docket. Unit 4, a tangentially fired CE boiler which burns low sulfur, sub-bituminous northern PRB coal, is rated at 805 MW gross output. The boiler started operation in 1984.

PM emissions are controlled by using a wet particulate scrubber that is designed to achieve approximately 99.8% particulate control efficiency.[250] As discussed previously in Section V.D.6.b., the contribution from point sources to primary organic aerosols, EC, $PM_{2.5}$ at Montana Class I areas is very small, and modeling tends to confirm that PM emissions from point sources do not have a very large impact. Therefore, we are proposing that additional controls for PM are not necessary for this planning period.

Colstrip Unit 4 burns low-sulfur (0.7%) coal and has a wet particulate scrubber that achieves 95% SO_2 control. Emissions for the last five years have averaged 0.08 lb/MMBtu. The scrubber has no provisions for bypass and the system includes a spare vessel for the unit which is available for use while servicing the other vessels.[251] Other upgrades to the scrubber are infeasible for the same reasons as described in the BART determinations for Colstrip Units 1 and 2. For these reasons, additional controls for SO_2 will not be considered or required in this planning period.

Currently, Colstrip Unit 4 has installed LNB with SOFA and a DPCS. These controls reduce NO_X emissions by 81%.

Step 1: Identify All Available Technologies

We identified that the following technologies to be available for Colstrip Unit 4: SCR and SNCR. These technologies have been described in the BART determinations for Colstrip Unit 1.

Step 2: Eliminate Technically Infeasible Options

We are not eliminating any options as technically infeasible. Thus, the technically feasible NO_X control options for Colstrip Unit 4 are SCR and SNCR.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

Baseline NO_X emissions from Colstrip Unit 4 are 5,347 tpy. A summary of emissions projections for the various control options is provided in Table 166.

TABLE 166—SUMMARY OF COLSTRIP UNIT 4 NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGIES

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
SCR	70.7	3,780	1,567
SNCR	25.0	1,336	4,011

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

Refer to the Colstrip Unit 1 section above for general information on how we evaluated the cost of compliance for NO_X controls. EPA's cost calculations can be found in the docket.

Table 167 provides a summary of estimated annual costs for the various control options.

TABLE 167—SUMMARY OF COLSTRIP UNIT 4 NO_X REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
SCR	17,441,422	4,607
SNCR	3,682,750	2,757

We relied on control costs developed for the IPM for direct capital costs for SCR and SNCR.[252] We then used methods provided by the CCM for the remainder of the SCR and SNCR. Specifically, we used the methods in the CCM to calculate total capital investment, annual costs associated with operation and maintenance, to annualize the total capital investment using the CRF, and to sum the total annual costs. We used a retrofit factor of ''1,'' reflecting an SCR and SNCR retrofit of typical difficulty in the IPM control costs.

As Colstrip Unit 4 burns sub-bituminous PRB coal having a low sulfur content of 0.91 lb/MMBtu (equating to a SO_2 rate of 1.8 lb/MMBtu),[253] it was not necessary to make allowances in the cost calculations to account for equipment modifications or additional

[250] Colstrip 3 & 4 Additional Response, Attachment 2, p. 2.

[251] *Id.*

[252] IPM, Chapter 5, Appendix 5–2A and 5–2B.

[253] U.S. DOE, Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants 1999 Tables, DOE/EIA–0191(99), Table 24 (June 2000).

maintenance associated with fouling due to the formation of ammonium bisulfate. These are only concerns when the rate of SO_2 is above 3 lb/MMBtu.[254] Moreover, ammonium bisulfate formation can be minimized by preventing excessive NH_3 slip. Optimization of the SNCR system can commonly limit NH_3 slip to levels less than the 5 ppm upstream of the pre-air heater.[255] EPA's detailed cost calculations for SNCR can be in the docket.

For SNCR we used a urea reagent cost estimate of $450 per ton taken from PPL's September 2011 submittal for Colstrip Units 1 and 2.[256] For SCR, we used an aqueous ammonia (29%) cost of $240 per ton,[257] and a catalyst cost of $6,000 per cubic meter.[258]

Factor 2: Time Necessary for Compliance

We estimate that SCR and SNCR can be installed within this planning period.

Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance

An SNCR process reduces the thermal efficiency of a boiler as the reduction reaction uses thermal energy from the boiler.[259] Therefore, additional coal must be burned to make up for the decreases in power generation. Using CCM calculations we determined the additional coal needed for Unit 4 equates to 172,200 MMBtu/yr. For an SCR, the new ductwork and the reactor's catalyst layers decrease the flue gas pressure. As a result, additional fan power is necessary to maintain the flue gas flow rate through the ductwork. SCR systems require additional electric power to meet fan requirements equivalent to approximately 0.3% of the plant's electric output.[260] Both SCR and SNCR require some minimal additional electricity to service pretreatment and injection equipment, pumps, compressors, and control systems. Note that cost of the additional energy requirements has been included in our calculations.

Non-air quality environmental impacts of SNCR and SCR were described in our BART analysis for Colstrip Unit 1.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Optional Factor: Modeled Visibility Impacts

We conducted modeling for Colstrip Unit 4 as described in section V.C.3.a. Table 168 presents the visibility impacts and benefits of SCR and SNCR at the 98th percentile of daily maxima for each Class I area from 2006 through 2008. Table 169 presents the number of days with impacts greater than 0.5 deciviews for each Class I area from 2006 through 2008.

TABLE 168—DELTA DECIVIEW IMPROVEMENT FOR NO_X CONTROLS ON COLSTRIP UNIT 4

Class I area	Baseline impact (delta deciview)	Improvement from SCR (delta deciview)	Improvement from SNCR (delta deciview)
North Absaroka WA	0.168	0.077	0.030
Theodore Roosevelt NP	0.485	0.260	0.091
UL Bend WA	0.468	0.249	0.081
Washakie WA	0.223	0.101	0.043
Yellowstone NP	0.148	0.057	0.026

TABLE 169—DAYS GREATER THAN 0.5 DECIVIEW FOR NO_X CONTROLS ON COLSTRIP UNIT 4

[Three Year Total]

Class I area	Baseline (days)	Using SCR	Using SNCR
North Absaroka WA	2	0	1
Theodore Roosevelt NP	14	2	8
UL Bend WA	14	0	11
Washakie WA	2	0	1
Yellowstone NP	1	0	1

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We have also considered an additional factor: The modeled visibility benefits of controls. We evaluated this factor for Colstrip Units 3 and 4, due to the size of Colstrip Units 3 and 4 in comparison with the other RP sources. For the more cost-effective option (SNCR), the modeled visibility benefits are relatively modest. For the more expensive option (SCR), the modeled visibility benefits, although more substantial, are not sufficient for us to consider it reasonable to impose this option in this planning period. Therefore, we are proposing that no additional NO_X controls will be required for this planning period on Colstrip Unit 4.

[254] IPM, Chapter 5, p. 5–9.

[255] ICAC, p. 8.

[256] NO_X Control Update to PPL Montana's Colstrip Generating Station BART Report, September 2011, p. 8.

[257] Email communication with Fuel Tech, Inc., March 2, 2012.

[258] Cichanowicz 2010, p. 6–7.

[259] CCM, Section 4.2, Chapter 1, p. 1–21.

[260] CCM, Section 4.2, Chapter 2, p. 2–28.

iv. Devon Energy Blaine County #1 Compressor Station

Devon Energy Blaine County #1 Compressor Station (Devon) operates two 5,500-hp Ingersoll Rand 616 natural gas compressor engines at its Blaine County #1 Compressor Station. The engines began operation in 1972 and combust natural gas. Emissions exit through a 45-foot stack. Additional information to support this four factor analysis can be found in the docket.[261]

PM and SO_2 emissions are relatively small (0.32 tpy of PM and 0.02 tpy of SO_2 per engine). Thus, SO_2 and PM emissions from these two engines are not significant contributors to regional haze and our determination only considers NO_X. Additional controls for SO_2 and PM will not be considered or required in this planning period.

Step 1: Identify All Available Technologies

We identified that the following technologies to be available for the compressor station: A continuous exhaust monitoring system (CEMS) with upgraded ignition system and air-fuel ratio control, a Dresser-Rand (D–R) mixing kit, a D–R mixing kit with screw-in prechambers, SCR, and non-selective catalytic reduction (NSCR). Both engines are already equipped with electronic air/fuel controllers, as well as electronic fuel valves and ignition. Emissions are adjusted through manual setpoint control of the air-to-fuel (A/F) ratio.

The CEMS involves continuous monitoring of the exhaust stack gases and making the necessary automatic adjustments to the ignition timing and air-fuel ratio to ensure optimization of the combustion cycle within the power cylinders. Load changes on the engine are compensated for in real time as opposed to the manual adjustments that currently take place. It is estimated that this system could achieve a 12% reduction in NO_X from the baseline case. This technology has been used in the past on similar engines.

A D–R mixing kit system, supplied by the engine manufacturer, improves the fuel delivery system to enhance fuel/air mixing, which improves exhaust NO_X levels and combustion stability. Dresser-Rand estimates that this system could achieve a 14% reduction in NO_X from the baseline case.

The D–R mixing kit with screw-in prechambers adds a new turbocharger and cooling system to the hardware of the mixing kit. This system further leans out the combustion of the existing engine to improve NO_X emissions performance. Dresser-Rand estimates that this system could achieve a 78% reduction in NO_X from the baseline case.

SCR has been described in general terms in the above BART determinations. SCR is considered feasible for this source. However, typical compressor engines operate at variable loads, thereby creating technical difficulties for SCR operation leading to periods of NH_3 slip or periods of insufficient NH_3 injection. It is estimated that this system could achieve a 75% reduction in NO_X from the baseline case. This technology is available from Catalytic Combustion, Inc and has been used in the past on similar engines.

NSCR is an add-on NO_X control technology for exhaust streams with low O_2 content. NSCR uses a catalyst reaction to simultaneously reduce NO_X, CO, and HC to water, carbon dioxide, and nitrogen. The catalyst is usually a noble metal.

One type of NSCR system injects a reducing agent into the exhaust gas stream prior to the catalyst reactor to reduce the NO_X. Another type of NSCR system has an afterburner and two catalytic reactors (one reduction catalyst and one oxidation catalyst). In this system, natural gas is injected into the afterburner to combust unburned HC (at a minimum temperature of 1700 °F). The gas stream is cooled prior to entering the first catalytic reactor where CO and NO_X are reduced. A second heat exchanger cools the gas stream (to reduce any NO_X reformation) before the second catalytic reactor where remaining CO is converted to carbon dioxide.

The control efficiency achieved by NSCR for NO_X ranges from 80 to 90%. The NO_X reduction efficiency is controlled by similar factors as for SCR, including the catalyst material and condition, the space velocity, and the catalyst bed operating temperature. Other factors include the A/F ratio, the exhaust gas temperature, and the presence of masking or poisoning agents. The operating temperature for an NSCR system ranges from approximately 700 °F to 1500 °F, depending on the catalyst.[262]

Step 2: Eliminate Technically Infeasible Options

We are not eliminating any of the control options as being technically infeasible.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

Baseline NO_X emissions are 372 tpy for each engine. A summary of emissions projections for the various control options is provided in Table 170.

TABLE 170—SUMMARY OF DEVON NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGIES

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)	Emissions reduction (tpy)	Remaining emissions (tpy)
		Unit 1		Unit 2	
NSCR	90	335	37	335	37
Mixing kit plus screw-in prechambers	78	290	82	290	82
SCR	75	279	93	279	93
Mixing kit	14	52	320	52	320
CEMS with upgraded ignition system and air-fuel ratio control	12	45	327	45	327

CAM Technical Guidance Document, Appendix B–16, Non-Selective Catalytic Reduction (Apr. 2002), available at: *www.epa.gov/ttnchie1/mkb/documents/B_16a.pdf.*

[261] Letter to Laurel Dygowski from Tracy Carter, no subject (June 18, 2009); Memo to Laurel Dygowski from Brad Nelson, RE: Four-Factor Analysis of Control Options for Devon Energy-Blaine County #1 Compressor Station—Chinook, Montana (July 17, 2009); Letter to Vanessa Hinkle from Tracy Carter, no subject, (Feb. 25, 2011); APMM Unit Recommendations/Considerations for AQP Unit Reasonable Progress Determination for Devon Energy Blaine County #1 Compressor Station, Prepared by Claudia Smith (Dec. 5, 2011); Email to Vanessa Hinkle from Alden West RE: Regional Haze RP Analysis (Oct. 26, 2011).

[262] CAM Technical Guidance Document, Appendix B–16, Non-Selective Catalytic Reduction (Apr. 2002), available at: *www.epa.gov/ttnchie1/mkb/documents/B_16a.pdf.*

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

We are adopting cost figures provided by Devon, except for the costs of NSCR. For NSCR, we estimated the annual cost to be $105,000 based on information used to support the 2002 NESHAP for Reciprocating Internal Combustion Engines (RICE).[263]

Table 171 provides a summary of estimated annual costs for the various control options.

TABLE 171—SUMMARY OF DEVON NO_X REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($) (same for both units)	Cost effectiveness ($/ton) Unit 1	Cost effectiveness ($/ton) Unit 2
NSCR	105,000	282	282
Mixing kit plus screw-in prechambers	261,000	897	897
SCR	308,822	1,108	1,108
Mixing kit	110,500	2,079	2,079
CEMS with Upgraded ignition system and air-fuel ratio control	29,100	652	652

Factor 2: Time Necessary for Compliance

Installation of a CEMS would take approximately nine weeks, installation of the mixing kit would take between 17 to 22 weeks, installation of a mixing kit plus screw-in prechambers would take 20 to 26 weeks, installation of SCR would take approximately 25 weeks, and installation of NSCR could take up to one year.

Factor 3: Energy and Non-Air Quality Environmental Impacts

A CEMS with an upgraded ignition system and air-fuel ratio control would actually improve fuel consumption. Installation of SCR would cause backpressure on the engine exhausts which would lead to a reduction of available power and an increase in engine fuel use. NSCR can potentially require up to a 5% increase in fuel consumption and up to a 2% reduction in power output.

A CEMS with an integrated ignition system and air-fuel ratio control, D–R mixing kit, or D–R mixing kit with screw-in prechambers would not have direct environmental impacts. Some manufacturers accept the return of spent catalyst that would be used by NSCR and SCR. If the catalyst could not be returned to the manufacturer, it would need to be disposed. In addition, SCR uses NH_3, which would have the possibility of being released if not properly managed.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We are also taking into account the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. Based primarily on the low cost of $282 per ton of NO_X removed, we propose to find NSCR is a reasonable control to address reasonable progress for the initial planning period, with an emission limit of 21.8 lb/hr (30-day rolling average).

We have eliminated lower performing options—upgraded ignition system and air-fuel ratio control, D–R mixing kit, SCR, and D–R mixing kit with screw-in prechambers because their cost effectiveness values are higher and/or the emission reductions are lower than NSCR. We are proposing an emission limit of 21.8 lbs/hr (30-day rolling average) based on a predicted control efficiency of 90%. The emission limit would apply on a continuous basis, including during startup, shutdown, and malfunction. We propose to require that Devon start meeting our proposed emission limit at Blaine County #1 Compressor Station as expeditiously as practicable, but no later than July 31, 2018. This is consistent with the requirement that the FIP cover an initial planning period that ends July 31, 2018. We propose this compliance deadline because of the equipment installation that is required.

In order to ensure the effectiveness of the NSCR, we are proposing to require the following work practices and operational requirements. We are proposing that Devon install a temperature-sensing device (*i.e.,* thermocouple or resistance temperature detectors) before the catalyst in order to monitor the inlet temperatures of the catalyst for each engine and that Devon maintain the engine at a minimum of at least 750 °F and no more than 1250 °F in accordance with manufacturer's specifications. Also, we are proposing that Devon install gauges before and after the catalyst for each engine in order to monitor pressure drop across the catalyst, and that Devon maintain the pressure drop within ±2″ water at 100% load plus or minus 10% from the pressure drop across the catalyst measured during the initial performance test. We are proposing to require Devon to follow the manufacturer's recommended maintenance schedule and procedures for each engine and its respective catalyst. We are proposing that Devon only fire each engine with natural gas that is of pipeline-quality in all respects except that the CO_2 concentration in the gas shall not be required to be within pipeline-quality.

We are proposing the following monitoring, recordkeeping, and reporting requirements for Devon:

- Devon shall measure NO_X emissions from each engine at least semi-annually or once every six month period to demonstrate compliance with the emission limits. To meet this requirement, we are proposing that Devon measure NO_X emissions from the

[263] US EPA, Office of Air Quality Planning and Standards, Regulatory Impact Analysis of the Proposed Reciprocating Internal Combustion Engines NESHAP, Final Report (Nov. 2002), available at *http://www.epa.gov/ttn/atw/rice/riceria.pdf*.

engines using a portable analyzer and a monitoring protocol approved by EPA.

• Devon shall submit the analyzer specifications and monitoring protocol to EPA for approval within 45 calendar days prior to installation of the NSCR unit.

• Monitoring for NO_X emissions shall commence during the first complete calendar quarter following Devon's submittal of the initial performance test results for NO_X to EPA.

• Devon shall measure the engine exhaust temperature at the inlet to the oxidation catalyst at least once per week and shall measure the pressure drop across the oxidation catalyst monthly.

• Each temperature-sensing device shall be accurate to within plus or minus 0.75% of span and that the pressure sensing devices be accurate to within plus or minus 0.1 inches of water.

• Devon shall keep records of all temperature and pressure measurements; vendor specifications for the thermocouples and pressure gauges; vendor specifications for the NSCR catalyst and the A/F ratio controller on each engine.

• Devon shall keep records sufficient to demonstrate that the fuel for the engines is pipeline-quality natural gas in all respects, with the exception of the CO_2 concentration in the natural gas.

• Devon shall keep records of all required testing and monitoring that include: the date, place, and time of sampling or measurements; the date(s) analyses were performed; the company or entity that performed the analyses; the analytical techniques or methods used; the results of such analyses or measurements; and the operating conditions as existing at the time of sampling or measurement.

• Devon shall maintain records of all required monitoring data and support information (e.g. all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required) for a period of at least five years from the date of the monitoring sample, measurement, or report and that these records be made available upon request by EPA.

Devon shall submit a written report of the results of the required performance tests to EPA within 90 calendar days of the date of testing completion.

v. Montana-Dakota Utilities Lewis & Clark Station

Montana-Dakota Utilities Company (MDU) submitted analyses and supporting information on March 17, 2009, February 2011 (Revised June 2011), June 14, 2011, February 10, 2012, and February 27, 2012.[264]

MDU owns and operates an electric utility power plant in Sidney, Montana, known as the L&C Station. The plant is rated at 52 MWs gross output (48 MWs net output) and consists of a single dry bottom, tangentially fired boiler, fueled with lignite coal. The boiler was installed in 1958.

PM emissions are controlled by a multi-cyclone dust collector, installed in 1957, with design control of 75–80%, as well as a flooded disc wet scrubber installed in 1975, designed for 98% PM control, with a nominal SO_2 control efficiency of approximately 15%, but which has achieved up to 60% control during certain operating conditions, mainly by the presence of calcium in the coal, but also by MDU's addition of lime to the existing scrubber system when the coal has lower calcium and higher sulfur content. Current NO_X controls consist of LNBs and a CCOFA system, installed in 1996. Estimated level of control is 33%.[265]

As discussed previously in Section V.D.6.b., the contribution from point sources to primary organic aerosols, EC, $PM_{2.5}$ at Montana Class I areas is very small, and modeling tends to confirm that PM emissions from point sources do not have a very large impact. Therefore, we are proposing that additional controls for PM are not necessary for this planning period.

SO_2

Current SO_2 controls consist of a wet scrubbing system (flooded disc wet scrubber, with lime addition as needed, depending on coal quality) with an estimated control efficiency of up to 60%.

Step 1: Identify All Available Technologies

We identified that the following technologies to be available for emissions reductions beyond those achieved by the current control configuration: Wet lime scrubbing/optimization of existing wet PM scrubber, lime SDA and baghouse, DSI and baghouse, and fuel switching to either PRB coal or to natural gas.

Wet lime scrubbing involves scrubbing the exhaust gas stream with slurry comprised of lime (CaO) in suspension. The process takes place in a wet scrubbing tower located downstream of a PM control device to prevent the plugging of spray nozzles and other problems caused by the presence of particulates in the scrubber. The SO_2 in the gas stream reacts with the lime to form $CaSO_3 \bullet 2H_2O$ and $CaSO_4$. This control option is functionally equivalent to ''in terms of concept and control efficiency. Forced oxidation is used in wet scrubbing systems to convert calcium sulfite to calcium sulfate (gypsum). Air is blown through spent lime reagent to accomplish this reaction. This often takes place in the bottom of the wet scrubber. Calcium sulfite is a watery compound and cannot be de-watered. It is typically disposed in ash ponds. Calcium sulfate is a solid. Wet scrubber blowdown containing calcium sulfate can be run through a filter press for calcium sulfate recovery. After filtration, calcium sulfate can be disposed of as a solid waste or it can be sold as a raw material for drywall production. The use of forced oxidation has an impact on the method of scrubber waste disposal, but does not appreciably impact SO_2 removal.

This wet scrubbing option at L&C Station would involve modification to the existing PM wet scrubber to increase SO_2 removal efficiency. The modification would primarily involve upgrade and optimization of the lime injection system. Expected total SO_2 emissions reduction would be approximately 70% on an annual basis, versus the estimated 60% control currently being achieved (about a 10% improvement). The scrubber lime injection system would be upgraded to achieve this additional removal.[266]

Lime SDA is a dry scrubbing system that sprays a fine mist of lime slurry into an absorption tower where the SO_2 is absorbed by the droplets. Once absorbed, the SO_2 reacts with lime to form $CaSO_3 \bullet 2H_2O$ and $CaSO_4$ within the droplets. The SDA temperature must be hot enough to ensure that the heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower. This leads to the formation of a dry powder, which is carried out with the gas and collected

[264] Response to Reasonable Progress Request for Information, Montana-Dakota Utilities Co. (''L&C Initial Response'') (Mar. 17, 2009); Emissions Control Analysis for Lewis & Clark Station Unit 1, Prepared for Montana-Dakota Utilities Co. by Barr Consultants (''L&C Emissions Control Analysis'') (Feb. 2011, rev'd June 2011); Revised Emissions Control Analysis for Lewis & Clark Station, in Response to EPA Request of November 5, 2010, Montana-Dakota Utilities Co. (''L&C Revised Emissions Control Analysis'') (June 14, 2011); Response to EPA Questions of January 19, 2012, Regarding Fuel Switch to Natural Gas, Basis for SCR Cost Calculation, and SDA Efficiency, Montana-Dakota Utilities Co. (''L&C Feb. 10, 2012 Response'') (Feb. 10, 2012); Response to EPA Questions of February 15, 2012, Regarding Cost of Fuel Switch to Natural Gas, Montana-Dakota Utilities Co. (''L&C Feb. 27, 2012 Response'') (Feb. 27, 2012).

[265] L&C Initial Response, pp. 3–5; L&C Emissions Control Analysis, p. 4.

[266] L&C Emissions Control Analysis, pp. 13–17.

with a fabric filter baghouse. Spray dryer absorption control efficiency is typically in the 70% to 90% range, but can be as high as 95%.[267] We used 95% control for this analysis. To accommodate the SDA control option, the existing particulate scrubber at L&C Station would need to be abandoned in place and replaced with a baghouse.[268] This is necessary to ensure the required system residence time for a dry control option; otherwise, the achievable control efficiency would be significantly decreased.[269]

DSI involves the injection of a lime or limestone powder into the exhaust gas duct work. The stream is then passed through a baghouse or ESP to remove the sorbent and entrained SO_2. The process was developed as a lower cost FGD option because the mixing occurs directly in the exhaust gas stream instead of in a separate tower. Depending on the residence time allowed in the system and gas duct temperature, sorbent injection control efficiency is typically between 50% and 70%. Based on the particulate loading of the existing control system, DSI is expected to achieve removal efficiencies of less than the design range in combination with existing controls. We used 70% control for this analysis. To accommodate the DSI control option, the existing particulate scrubber at L&C Station would need to be abandoned in place and replaced with a new baghouse. Again, this is necessary to ensure the required system residence time for a dry control option; otherwise, the achievable control efficiency would be significantly decreased.[270]

Fuel switching is a control technology option. Blending of subbituminous PRB coal is already employed at L&C Station, in instances where relatively poor quality lignite coal is provided to the plant. MDU's boiler is currently permitted to blend PRB coal with the primary lignite fuel.[271] Therefore, we consider a fuel switch to PRB coal as primary fuel to be an available SO_2 control option, although, since there is no appreciable difference in the sulfur content (weight percent) of PRB coal versus lignite coal, this option might yield only marginal SO_2 reductions.[272] Also, since MDU has provided data indicating natural gas is used to some extent (about 0.37% of total heat input to the boiler in 2002, by our calculations, based on information supplied by MDU),[273] we consider a fuel switch to natural gas as primary fuel to be another available control option for SO_2. Since pipeline-quality natural gas has negligible sulfur content, we would expect a greater than 99% reduction in SO_2. To supply sufficient natural gas to serve as primary fuel for the boiler, a new 22-mile pipeline from the nearest connection point to L&C Station would have to be constructed.[274]

Step 2: Eliminate Technically Infeasible Options

Although switching to coals with lower sulfur content and higher Btu content represents a viable pre-combustion method of reducing SO_2 emissions, there are limitations to achievable blending. Switching to any fuel with an appreciably different composition and energy content would require boiler surface and other design changes. Previous test burns of PRB coal at the boiler confirm that the high flue gas temperatures, resulting from the use of PRB coal, cause significant fouling to boiler walls and other boiler surfaces. Due to the physical properties of PRB coal, coal mills and coal piping to the boiler would also need to be replaced, along with the addition of a railcar unloading system. A re-design of the existing boiler does not constitute a feasible retrofit control option. Further, there is no appreciable difference in the sulfur content (weight percent) of the subbituminous coal supplement, and reduced calcium/magnesium concentrations present in the subbituminous coal would also result in less inherent SO_2 control. Finally, the on-site coal inventory is fairly limited (generally 2–3 days' supply of lignite), due primarily to lack of property to safely store additional inventory.[275] Therefore, a switch to PRB coal as primary fuel is not considered further in this evaluation.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

A summary of emissions projections for the various control options is provided in Table 172. For all options, we relied on the estimated control efficiencies, estimated emissions reductions, and emissions baseline provided by MDU. The emissions baseline of 1,002.1 tpy used in our analysis reflects an estimated 60% level of control already being achieved by the existing scrubber system. The control efficiencies listed in the table below are the degree of control that is expected to be achieved on baseline SO_2 emissions (1,002 tpy).

TABLE 172—SUMMARY OF MDU LEWIS AND CLARK SO_2 REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGIES

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
Fuel switch to natural gas	99+	1,002	Negligible
SDA with baghouse	85	850.3	151.8
DSI with baghouse	10	100.2	901.9
Existing scrubber mod.	10	100.2	901.9

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

Table 173 provides a summary of estimated annual costs for the various control options.

[267] L&C Feb. 10, 2012 Response, p. 3.
[268] L&C Emissions Control Analysis, p. 15.
[269] *Id.*
[270] *Id.,* pp. 13, 15.
[271] *Id.,* pp. 8–10.
[272] *Id.*
[273] L&C Initial Response, p. 7.
[274] L&C Feb. 10, 2012 Response, p. 2.
[275] L&C Emissions Control Analysis, p. 8–10.

TABLE 173—SUMMARY OF MDU LEWIS & CLARK REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
Fuel switch to natural gas	21,919,094	21,875
SDA with baghouse	10,055,056	11,825
DSI with baghouse	2,840,734	28,350
Existing scrubber mod.	138,637	1,383

We have relied on costs provide by MDU for these control options. The high annual cost of a fuel switch is due partly to the need to construct a new 22-mile natural gas pipeline, and partly to the large difference in cost of natural gas versus lignite coal. Natural gas would cost about five times as much as lignite coal to fuel the boiler.

Factor 2: Time Necessary for Compliance

For the option involving a fuel switch to natural gas as primary fuel, we estimate several years would be needed to secure the necessary rights-of-way and install a new 22-mile pipeline that MDU has stated would be needed to provide a sufficient supply of natural gas.[276] For the SDA-with-baghouse and DSI-with-baghouse control options, we relied on an estimate from the Institute of Clean Air Companies (ICAC) that approximately 30 months is required to design, build and install SO_2 scrubbing technology.[277] For the option involving modification to the existing scrubbing system, we relied on MDU's estimate of 6 to 12 months to conduct an optimization study to evaluate scrubber capabilities and identify operational constraints.[278]

Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance

A fuel switch to natural gas as primary fuel could significantly increase the demand for natural gas in the region and could increase natural gas prices for other consumers of natural gas in the region, as well as create impacts associated with more production of natural gas in the region. For the SDA-with-baghouse control option, as well as for the DSI-with-baghouse control option, energy impacts would include a blower requiring increased energy use and an associated indirect CO_2 emissions increase. For the option of modifying the existing wet scrubber system, no appreciable energy impacts are expected. There is, however, a potential for additional water consumption and wastewater generation.[279]

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. The costs per ton of pollutant reduced are excessive for the three most expensive options. We are also taking into account the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. Based on costs of compliance, the small size of MDU L&C, and the relatively small baseline Q/D, we propose to eliminate the more expensive control options (fuel switch to natural gas, SDA with baghouse, and DSI with baghouse). The most cost-effective control option (scrubber modifications) would reduce SO_2 emissions by 100 tpy, which equates to a 5.5% reduction in overall emissions of SO_2 + NO_X for this facility, or a reduction of Q/D from 29 to 27. Based on the costs of compliance, the relatively small size of MDU L&C, the baseline Q/D, and the modest reduction in Q/D, we find it reasonable to eliminate this option. We therefore propose to not require additional SO_2 controls for this planning period.

NO_X

Current NO_X controls consist of LNBs and a CCOFA system, with estimated control efficiency of 33%.

Step 1: Identify All Available Technologies

We identified that the following technologies to be available for emissions reductions beyond those achieved by the current control configuration: Fuel switching to PRB coal or to natural gas, SCR + SOFA/LNB, SNCR, SOFA/LNB, and SNCR with SOFA/LNB.

We consider fuel switching to PRB coal or to natural gas, as primary fuel for the boiler, as an available control for NO_X, for the same reasons as described in our SO_2 analysis. With regard to a potential switch to PRB coal, higher heat content of coal can yield lower NO_X emissions in lb/MMBtu. The lignite coal used at L&C Station has an average heating value of 6,435 Btu/lb.[280] PRB coal typically ranges from 8,000 to 8,500 Btu/lb and therefore could be expected to have lower NO_X emissions than lignite coal, per ton of coal fired. Similarly, natural gas could be expected to produce lower NO_X emissions than lignite coal. We used a 65% reduction in our analysis.[281]

SCR was generally described in our BART analysis for CELP. SCR has been demonstrated to achieve high levels of NO_X reduction in the range of 80% to 90% (or higher) control, for a wide range of industrial combustion sources, including PC, cyclone, and stoker coal-fired boilers and natural gas-fired boilers and turbines. For our SCR analysis, we included SOFA and LNB upstream of the SCR controls, on the basis that these controls are much less expensive than SCR and would enable the SCR system to use less reagent. Our calculations reveal that a control system consisting of SCR + SOFA/LNB would be more cost-effective than SCR alone

[276] L&C Feb. 10, 2012 Response, p. 2.

[277] Report from Bradley Nelson, EC/R Inc. to Laurel Dygowski of EPA, Four-factor Analysis of Control Options for MDU L&C Station, p. 5 (July 3, 2009).

[278] L&C Emissions Control Analysis, p. 17.

[279] L&C Emissions Control Analysis, p. 16.

[280] L&C Feb. 27, 2012 Response. MDU cited typical heat content of 6,435 Btu/lb for lignite coal, based on 2009–2011 average from FERC Form 1/EIA 923 reports.

[281] The AP–42 emission factor for natural gas is 170 lb/MMSCF. MDU's February 27, 2012 letter to EPA states that annual natural gas consumption, if natural gas is used as primary fuel, would be 3,283 MMSCF. This yields 279 tpy of NO_X emissions. Baseline NO_X emissions used by MDU in its June 2011 analysis, with lignite coal as primary fuel, are 802 tpy. Switching to natural gas would therefore represent a potential 65% reduction in NO_X emissions.

and would also achieve a higher level of control than SCR alone. We have used 87.5% control as our estimate for the combined SCR + SOFA/LNB system.[282]

A description of SNCR was provided in our BART analysis for CELP. We used 38% control effectiveness for SNCR alone, and 50% control effectiveness for the control option of SNCR with SOFA/LNB.

L&C Station is a member of Midwest Independent Transmission System Operator (MISO) and, as such, is operated as called upon based on energy demand and price. Generally, combustion systems on boilers are not optimized for low load operation, including associated NO_X emissions. This is important because the efficiency of many air emission controls cannot be guaranteed at low load operating conditions. This is especially true for SNCR. Therefore, to reflect actual emission reductions on cost per ton basis, an SNCR scenario at low load operation is also presented in our analysis, using 23 MW capacity as the low load operational case. Based on a preliminary SNCR engineering assessment that includes the temperature, residence time, and the current level of NO_X control, an emissions reduction of approximately 15% to 30% would be expected at low load conditions. We used 16% for our analysis.

SOFA was described in our BART analysis for Colstrip Unit 1. LNB was described in our analysis for CELP. SOFA technology is compatible with the existing LNB.

LNBs typically achieve NO_X emission reductions of 25% to 50% as compared to uncontrolled emissions. LNBs are currently used at L&C Station. Based on the currently achieved emission rates, a combined reduction in the range of 30% to 40% is expected at L&C Station with the addition of SOFA and new LNB. We used 38% for our analysis.

Step 2: Eliminate Technically Infeasible Options

We consider fuel switching to PRB coal to be technically infeasible, for reasons already described in Step 2 of our SO_2 analysis.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

A summary of emissions projections for the various control options is provided in Table 174. We relied on information from MDU for estimated control efficiencies, expected emission reductions, and baseline emissions, with the exception of HDSCR + SOFA/LNB, for which we performed our own analysis. The control efficiencies listed in the table below, other than for the SNCR low-load scenario, are the degree of reduction that is expected to be achieved on actual controlled baseline NO_X emissions of 802 tpy. Similarly, the emission reductions in tpy in the table are reductions from the baseline emissions. For the SNCR low-load scenario, the baseline emissions, control efficiency and emissions reduction are those that correspond to low load operation (23 MW).

TABLE 174—SUMMARY OF MDU LEWIS & CLARK NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGIES

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
HDSCR + SOFA/LNB	87.5	693	109
Fuel switch to natural gas	65	523	279
SNCR with SOFA/LNB	50	401	401
SOFA/LNB	38	301	501
SNCR	38	301	501
SNCR (low load) [1]	16	57.6	298

[1] Baseline emissions for the low load scenario are 356 tpy.

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

Table 175 provides a summary of estimated annual costs for the various control options. We relied on MDU's cost figures, with the exception of HDSCR + SOFA/LNB, for which we performed our own cost calculations, using a combination of EPA's OAQPS CCM and control costs from EPA's IPM.

TABLE 175—SUMMARY OF MDU LEWIS & CLARK NO_X REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
HDSCR + SOFA/LNB	3,361,965	4,853
Fuel switch to natural gas	21,919,094	41,934
SNCR with SOFA/LNB	1,093,962	2,729
SOFA/LNB	364,546	1,213
SNCR	761,654	2,533
SNCR (low load)	565,673	9,817

[282] MDU NO_X control cost analysis by US EPA Region 8 for SCR, SOFA/LNB, and SCR + SOFA/LNB, Summary Spreadsheet (Mar. 7, 2012).

Factor 2: Time Necessary for Compliance

For combustion modifications such as SOFA and/or LNB, furnace penetration would be required and, as such, will need to align with a major outage. The next planned outage is spring of 2018.[283] Therefore, it might not be possible to ensure that SOFA or LNB could be installed within the first planning period for regional haze requirements under the CAA. If HDSCR + SOFA/LNB is the chosen control option, the construction schedule could extend into many months. If SNCR is the chosen control option, installation would likely be much quicker. For the option involving a fuel switch to natural gas as primary fuel, several years might be needed to secure the necessary rights-of-way and install a new 22-mile pipeline that MDU has stated would be needed to provide a sufficient supply of natural gas.[284]

Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance

A fuel switch to natural gas as primary fuel could significantly increase the demand for natural gas in the region and could increase natural gas prices for other consumers of natural gas in the region, as well as create impacts associated with more production of natural gas in the region. Other control options, however, would have minimal energy impacts.

Depending on HDSCR installation in relation to existing controls, NH_3 slip can generally cause additional NH_3 to be emitted to air or water. As NH_3 is both a visibility impairing air pollutant and a wastewater regulated pollutant, air emissions and water discharges can be impacted. This is also a potential SNCR impact. Also, spent catalyst from SCR produces an increase in solid waste. Finally, for combustion modifications (SOFA and/or LNB), there is a potential for increased CO emissions from the boiler. During normal operation at L&C Station, CO levels are currently on the order of 20 ppm. Generally, CO performance guarantees are in the 100 ppm to 200 ppm range for LNBs.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

[283] L&C Emissions Control Analysis, p. 26.

[284] L&C Feb. 10, 2012 Response, p. 2.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: the cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We are also taking into account the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. Based on costs of compliance, the small size of the facility, and the relatively small baseline Q/D, we propose to eliminate the more expensive control options (fuel switching to natural gas and HDSCR + SOFA/LNB). For similar reasons, taking into account costs in the low load scenario, we propose to eliminate SNCR and SNCR + SOFA/LNB. Finally, for the most cost effective option (SOFA/LNB), emissions reductions would be fairly small (300 tpy), which would result in approximately 16.6% reduction in overall emissions of SO_2 + NO_X for this facility, or a reduction of Q/D from 29 to 24. Based on the costs of compliance, the relatively small size of MDU L&C, and the modest reduction in Q/D, we find it reasonable to eliminate this option. We therefore propose to not require NO_X controls for this planning period.

vi. Montana Sulphur and Chemical

Montana Sulphur and Chemical Company (MSCC) is a sulfur recovery source located in Billings, Montana. Additional information to support this four factor analysis can be found in the docket.[285]

MSCC converts the raw sulfur compound from fuel gases, acid gases and other materials to create marketable products, including: low sulfur fuel gas, elemental sulfur, dry fertilizers, hydrogen gas, hydrogen sulfide, and carbon and sodium sulfates. MSCC receives sulfur-containing fuel gases from the ExxonMobil refinery, desulfurizes these gases in its amine unit, and returns low-sulfur fuels back to the refinery. This process reduces sulfur oxide emissions that might otherwise be emitted to the atmosphere at the oil refinery site.

At MSCC, acid gases are processed in a multistage Claus process and tail gas incinerator. In 1998, MSCC installed a SuperClaus Process, which further desulfurizes Claus tail gases by selective partial oxidation and controls emissions of SO_2. In 2008, a second SuperClaus unit was installed in parallel to the first unit, so that sulfur and fuel gas processing can continue during periods of repair and maintenance.

[285] Reasonable Progress (RP) Four-Factor Analysis of Control Options for Montana Sulphur & Chemical Company in Billings Montana; Response to Request for Information, Reasonable Progress for Montana Sulphur & Chemical Co, pursuant to Section 114(A) of the Federal Clean Air (Feb. 6, 2012).

The sulfur recovery process and its related stack is the preponderant source of SO_2 emissions from the facility and is the only emissions unit included in our analysis.

PM emissions from the sulfur recovery process are estimated to be only 1 tpy. As discussed previously in Section V.D.6.b., the contribution from point sources to primary organic aerosols, EC, $PM_{2.5}$ and PM_{10} at Montana Class I areas is very small, and modeling tends to confirm that PM emissions from point sources do not have a very large impact. Therefore, we are proposing that additional controls for PM are not necessary for this planning period.

NO_X emissions also are relatively small, at 3 tpy. Thus, NO_X emissions from the unit are not significant contributors to regional haze. Additional controls for NO_X will not be considered or required in this planning period. We are therefore considering controls only for SO_2 for this planning period.

Step 1: Identify All Available Technologies

We identified that the following technologies to be available: extending the Claus reaction into a lower temperature liquid phase (the Sulfured® process) and tail gas scrubbing (Wellman-Lord, SCOT, and traditional FGD processes).

In the Sulfured® process, the Claus reaction is extended at low temperatures (260 to 300°F) to recover SO_2 and H_2S in the tail gas. Tail gas passes through one of three reactors on line at a given time. Two reactors are on either heating or cooling cycles while the third is on the gas stream. Gas flow is switched from the reactors and is determined by the sulfur-holding capacity of each catalyst bed in the reactors. Sulfur is vaporized by using inert gas from a blower, resulting in the regeneration of the catalyst bed. The inert gas is then cooled in a condenser, where the liquid sulfur is removed. The hot regenerated catalyst bed must be cooled before going back on the gas stream.

The Wellman-Lord is an oxidation tail gas scrubber that uses sodium sulfite (Na_2SO_3) and sodium bisulfate ($NaHSO_3$) to react with SO_2 gas from the Claus incinerator to form bisulfate. The incinerator gases must be cooled and quenched before scrubbing, subjected to misting after scrubbing, and reheated afterwards. The bisulfate solution is regenerated to sodium sulfite in a steam-energized evaporator. The concentrated wet SO_2 gas stream from the evaporator is partially condensed and some of the liquid water is used to dissolve sulfite crystals. The remaining enriched SO_2 gas stream is recycled back to the Claus plant and used to recover additional sulfur by reaction with the incoming hydrogen sulfide.

The Shell Claus Off-Gas Treatment (SCOT) process is another example of reduction tail gas scrubbing. In the SCOT process, and numerous variants, tail gas from the sulfur recovery unit (SRU) is re-heated and mixed with a hydrogen-rich reducing gas stream. Heated tail gas is treated using a catalytic reactor where the free sulfur, SO_2, and reduced sulfur compounds are substantially reconverted to H_2S. The H_2S-rich gas stream is then routed to a cooling/quench system where the gases are cooled. Excess condensed water from the quench system is routed to a separate sour water system for treatment and disposal. The cooled quench system gas effluent is then fed to an absorber section where the acidic gas comes in contact with a selective amine solution and is absorbed into solution; the amine must selectively reject carbon dioxide gas to avoid problems in the following steps, and must not be exposed to unreduced gases or oxygen (e.g., unconverted SO_2 or sulfur) that may arise during malfunctions. The rich solution is separately regenerated using steam, cooled and returned to the scrubber/absorber. The H_2S-rich gas released at the regenerator is reprocessed by the SRU.

Other traditional FGD technologies include: Wet lime scrubbers, wet limestone scrubbers, dual alkali wet scrubbers, spray dry absorbers, DSI, and CDS. All of these technologies were described in previous sections (see the BART analysis for Corette and the four factor analyses for CELP, YELP, and MDU, L&C Station).

Step 2: Eliminate Technically Infeasible Options

The Wellman-Lord scrubber is infeasible for MSCC. This system can require significant space, especially in retrofit applications. There is limited space at MSCC. Also, the purge system required by this process would generate excess acid water that would require onsite management and onsite or offsite disposal. For these reasons, the Wellman Lord system was not considered further.

SDA and DSI are not technically feasible because the flue gas SO_2 concentrations at MSCC are too high. These technologies cannot be used when concentrations are greater than 2000 ppm. The average concentration of SO_2 in the flue gas at MSCC ranges from 2,100 to 6,000 ppm. For this reason, SDA and DSI were not considered further.

MSCC has very limited space to install wet systems or to manage the waste streams generated by wet systems (wet lime scrubbers, wet limestone scrubbers, and dual alkali wet scrubbers). These systems can require significant space, especially in retrofit applications. There is limited space at MSCC. Also, these processes would generate excess water that would require onsite management and onsite or offsite disposal. Wet systems would require an onsite dewatering pond and landfill to process and dispose of scrubber sludge. For these reasons, the wet systems were not considered further.

CDS cannot be used at MSCC because it would result in high particulate loading. It would be necessary to control those particulates. Because of the high particulate loading, the pressure drop across a fabric filter would be unacceptable; therefore, ESPs are generally used for particulate control for power plants. Either type of particulate control device would require substantial space, which is not available at MSCC. Based on limited technical data from non-comparable applications and our engineering judgment, we have determined that CDS is not technically feasible for this facility. For this reason, CDS was not considered further.

Both the SCOT and Sulfured® processes are feasible; however, in the BART Guidelines, EPA states that it may be appropriate to eliminate from further consideration technologies that provide similar control levels at higher cost. See 70 FR 39165 (July 6, 2005). We think it appropriate to do the same for RP determinations. In this case, Sulfured® systems reportedly can achieve 98% to 99.5% sulfur recovery efficiency while SCOT can reportedly achieve sulfur recovery as high as 99.8% to 99.9%. The cost is higher for the Sulfured® system when compared to the SCOT process. Because the SCOT process is more effective and costs less than the Sulfured® system, the Sulfured® system was not considered further.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Baseline SO_2 emissions from MSCC are 1,452 tpy. A summary of emissions projections for the SCOT process, the only remaining control technology, is provided in Table 176.

TABLE 176—SUMMARY OF MSCC SO_2 REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGY CONTROL EFFECTIVENESS

Control option	Control effectiveness [1] (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
SCOT	99.9	871	581

[1] Overall control efficiency is shown. Incremental control efficiency, over the current Superclaus™ Process is 60%.

Factor 1: Costs of Compliance

Table 177 provides a summary of estimated annual costs and cost effectiveness for the SCOT process.

TABLE 177—SUMMARY OF MSCC SO_2 REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
SCOT	7,705,000	5,441

We are adopting cost figures provided by MSCC, except that we annualized the capital cost using a 7% interest rate and 20-year equipment life (which yields a CRF of 0.0944), as specified in the Office of Management and Budget's Circular A–4, Regulatory Analysis.[286] The capital cost is annualized by multiplying the total capital investment by the CRF (0.0944). We also used a control efficiency of 99.9% for the SCOT process.

Factor 2: Time Necessary for Compliance

The SCOT process could be installed in 18 to 36 months.

Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance

The SCOT process requires substantial additional energy for operation. The tail gas from the Claus unit would need to be heated prior to entering a reducing reactor and/or heating recycled gas for regeneration requirements. Low-temperature based systems such as the SCOT system would also require additional fuel for reheat of the final tail gas for incineration prior to discharge. SCOT systems also require substantial electricity to operate numerous pumps, coolers and a condenser. Additional power is required to provide relatively large amounts of cooling water. Additional fuel and power energy (and equipment) is required for processing of the new sour water waste that is continuously produced in the quench process necessary for scrubbing. Additional details of the energy requirements for the SCOT process are described in the docket.

The quench system in the SCOT system produces a sour water effluent that requires treatment prior to disposal. This effluent contains hydrogen sulfide, and may contain other troublesome species as well, particularly during upset conditions. An engineered facility needs to be installed at MSCC to manage this waste stream.

Factor 4: Remaining useful life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We are also taking into account the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. Based on costs of compliance for the only control option (SCOT), the relatively small size of the facility, and the relatively small baseline Q/D, we propose to eliminate this option. Therefore, we are proposing that no additional controls for SO_2 will be required for this planning period.

vii. Plum Creek Manufacturing

Plum Creek Manufacturing's Columbia Falls Operation, in Columbia Falls, Montana consists of a sawmill, a planner, and plywood and medium density fiberboard (MDF) processes. Additional information to support this four-factor analysis can be found in the docket.[287] This RP analysis focuses on four emitting units at the Columbia Falls Operation: the Riley Union hog fuel boiler (Riley Union boiler), two Line 1 MDF dryer sander dust burners (Line 1 sander dust burners), and the Line 2 MDF dryer sander dust burner (Line 2 sander dust burner). The Riley Union boiler is used as a load-following steam generator for the dry kilns, plywood press, log vats, and MDF platen press. Downstream from the spreader-stoker grate, there are sander dust burners that are capable of supplementing 10% of the heat rate capacity of the boiler. These burners are normally fired with sander dust, but have the ability to fire natural gas during sander dust shortages and startup.

The Line 1 MDF dryers include two direct-contact dryers, a core fiber dryer, and a face fiber dryer. One Cone sander dust burner supplies heat to each dryer. The Line 1 fireboxes are one-quarter the size of the Line 2 firebox.

The Line 2 MDF dryers are direct-contact dryers. The flue gas from the combustion chamber provides heat for the first- and second-stage dryer lines. The design of the Line 2 burner employs staged combustion, with a rich zone followed by a lean zone reducing peak flame temperature, thereby reducing thermal NO_X emissions.

The Riley Union boiler exhausts to a dry ESP that was installed in 1993. The Line 1 dryer exhausts combine with the Line 1 press vents and metering bin baghouse exhausts before being controlled by a wet ESP that was installed in 1995. They emit to the atmosphere through two 80-foot stacks. The Line 2 dryer exhausts to a Venturi scrubber (installed in 2001) before emitting to the atmosphere through three 40-foot stacks. As discussed previously in Section V.D.6.b., the contribution from point sources to primary organic aerosols, EC, $PM_{2.5}$ and PM_{10} at Montana Class I areas is very small, and modeling tends to confirm that PM emissions from point sources do not have a very large impact. Therefore, we are proposing that additional controls for PM are not necessary for this planning period.

SO_2 emissions are relatively small (18 tpy for all units combined). Thus, SO_2 emissions from these units are not significant contributors to regional haze, and additional controls for SO_2 will not be considered or required in this planning period. We are therefore only considering controls for NO_X for this planning period.

Riley Union Boiler

Step 1: Identify All Available Technologies

The Riley Union Boiler does not currently have post-combustion or low NO_X combustion technology. We identified that the following technologies to be available: SCR, RSCR, SNCR, SNCR/SCR hybrid, staged combustion, fuel staging, LNB, OFA, LEA, and FGR.

SCR, SNCR, LNB, OFA, LEA and FGR were described in our analysis for CELP.

RSCR uses a regenerative thermal oxidizer (or waste heat transfer system) to bring cool exhaust gas back up to the

[286] Available at: *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

[287] Letter from Thomas Ray to Vanessa Hinkle (Feb. 28, 2011); Reasonable Progress (RP) Four-Factor Analysis of Control Options for Plum Creek Manufacturing/Columbia Falls Operations.

temperature required for the SCR catalyst to be effective at reducing NO_X to nitrogen and water. RSCR is a good option for an exhaust gas that has constituents requiring removal prior to introduction into the catalyst (to prevent fouling or plugging), such as high PM concentrations.

The SNCR/SCR hybrid approach involves injecting the reagent (NH_3 or urea) into the combustion chamber, which is a higher temperature zone than traditional SCR injection. This provides an initial reaction that is similar to SNCR. A catalyst is placed in the downstream flue gas to further reduce NO_X and any reagent that remains.

Staged combustion can be achieved through a wide variety of methods and techniques, but in general creates a fuel-rich zone followed by a fuel lean zone. This reduces the peak flame temperature and the generation of thermal NO_X.

Fuel staging is a technique that uses 10% to 20% of the total fuel input downstream from the primary combustion zone. The fuel in the downstream secondary zone acts as a reducing agent to reduce NO emissions to N_2. Natural gas or distillate oil usually are used in the secondary combustion zone.

Step 2: Eliminate Technically Infeasible Options

SCR catalysts may be fouled or plugged by exhaust gas that contains high concentrations of PM, as is the case with the combustion of wood, biomass, or hog fuel. To prevent the premature failure of the catalyst, the PM must be removed from the exhaust stream prior to SCR. At this facility, the exhaust from the boiler's ESP will not meet the minimum temperature required for SCR (without reheat). Since the PM loading is too high for high dust SCR prior to PM controls; and the gas is too cool after the PM control equipment for a low dust SCR (downstream of the ESP). For these reasons, SCR was not considered further.

Since the PM concentrations in the exhaust of the Riley Union boiler would require the PM controls to precede the catalyst section of the hybrid system, reheat would be required. RSCR is considered to be feasible without firebox/SNCR injection, therefore SNCR/SCR Hybrid systems were not considered further.

Further staged combustion is not possible for the Riley Union boiler. The boiler is a stoker boiler with sander dust burners downstream from the stoker. In order to create a further staged combustion process (and lower flame temperature), the energy density must be reduced in the combustion fuel. This means that more volume would be required to accommodate the current heat rate. In addition to the space constraint, as with OFA, it is unlikely that the current design could further stratify the rich and lean combustion zones (either through decreased under-fire air, or increased OFA), due to the minimum air flow needed to cool the stoker grate and maintain an even heat release rate. For these reasons, staged combustion was not considered further.

The Riley Union boiler already employs fuel staging by having a stoker grate for a majority of the heat input followed by sander dust burners downstream of the grate. Further fuel staging is infeasible for the boiler. For this reason, fuel staging was not considered further.

LNBs are not feasible for spreader-stoker boilers, as they do not use burners for a majority (90% in this case) of the heat input. Sander dust burners are located downstream from the stoker grate; however, their small size may restrict the ability to create conditions necessary for a LNB. For LNB technology to be effective, the rich zone must precede the lean zone. In this case, the secondary combustion zone burners would not have sufficient space to accommodate a larger flame front characterized by LNB technology. In addition, lowering the flame temperature at that location may negatively affect the function of the secondary combustion zone, which could result in increased emissions of some pollutants. For these reasons, LNB technology was not considered further.

In order to implement OFA on the boiler, further modifications would be required to add OFA ports. The OFA ports would need to be installed at the same location as the current sander dust burners. In addition, installation of OFA ports will increase the size/volume of the flame front, in turn, increasing flame impingement on the boiler walls, which may lead to tube failure. Flame impingement may also increase quenching of the flame thereby increasing emissions associated with incomplete combustion. The reducing atmosphere of the rich primary zone also may result in accelerated corrosion of the furnace, and grate corrosion and overheating may occur in stokers as primary air flow is diverted to OFA ports. Some level of staged combustion is already achieved through fuel staging (by use of the downstream sander dust burners). Further staging of the combustion process through OFA (or other techniques) is technically infeasible without increasing the boiler volume or decreasing the heat input rate. For these reasons, OFA was not considered further.

LEA is not compatible with the design of the boiler. The boiler is a stoker boiler that operates on the principle of creating an even release of heat across the entire grate. In order to achieve optimal conditions, sufficient air flow is required from beneath the grate. In addition sufficient air flow is needed to keep the grate and parts exposed to combustion material below their maximum operating temperatures. For these reasons, LEA is not considered further.

Similarly, FGR creates a LEA condition, but may not affect the under fire air needed to properly operate the stoker grate system. In order to prevent high loss on ignition and increased emissions associated with incomplete combustion (and the LEA condition) the volume of the boiler's combustion chamber would likely need to be increased to maintain the current steam rate and overall heat release rate, and thus is not compatible with the design of the boiler. FGR is a technique with multiple mechanisms for reducing NO_X, including reducing the available oxygen, since some exhaust gas replaces oxygen rich ambient air. For this reason, FGR is not considered further.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Baseline NO_X emissions from the boiler are 587 tpy. A summary of emissions projections for RSCR and SNCR, the only remaining control technologies, are provided in Table 178. Further information can be found in the docket.

TABLE 178—SUMMARY OF BOILER NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGY

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
SNCR	35	205	382

TABLE 178—SUMMARY OF BOILER NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGY—Continued

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
RSCR	75	440	147

Factor 1: Costs of Compliance

Table 179 provides a summary of estimated annual costs and cost effectiveness for SNCR and RSCR.

TABLE 179—SUMMARY OF BOILER NO_X REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
SNCR	$294,377	$1,436
[1] RSCR	748,097	1,700

[1] Further information on our cost calculation can be found in the docket in the document titled Reasonable Progress (RP) Four-Factor Analysis of Control Options for Roseburg Forest Products Co./Missoula Particleboard (a similar type source to Plum Creek's boiler).

For SNCR, we are adopting cost figures provided by Plum Creek,[288] except that we annualized the capital cost by multiplying the capital cost by a CRF that corresponds to a 7% interest rate and 20-year equipment life (which yields a CRF of 0.0944), as specified in the Office of Management and Budget's Circular A–4, Regulatory Analysis.[289] For RSCR, we are adopting the total annual cost for RSCR for the SolaGen sander dust burner at Roseburg Forest Products. This is likely an underestimation of the cost for the boiler dryers at Plum Creek, because the boiler at Plum Creek is larger than the SolaGen sander dust burner at Roseburg.

Factor 2: Time Necessary for Compliance

RSCR systems can be operational within eight months to one year. Because RSCR includes much of the equipment needed for SNCR, with additional equipment (the catalyst for instance), we have assumed that SNCR could be installed within a similar timeframe to that quoted for RSCR. Therefore, SNCR also can be installed and operational within eight months to one year.

Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance

RSCR requires the reheat of the flue gas, either through a heat exchanger that uses plant waste heat, and/or through direct reheat of the flue gas by additional combustion or electrically powered heating elements. Although specific estimates of resources needed to operate RSCR on the Columbia Falls boiler were not available, we have examined estimates presented for a similar source (Roseburg Forest Products) to illustrate the approximate quantity of resources needed to run a RSCR system. Table 180 provides estimates of these additional resources that are necessary for RSCR.

TABLE 180—ADDITIONAL AMMONIA, NATURAL GAS, ELECTRICITY, AND STEAM REQUIRED FOR RSCR

	Ammonia (NH_3)	Natural gas	Electricity	Steam
RSCR usage per system	300,000 to 400,000 gal/year.	2 million scf/year to 9.7 million scf/year.	930,000–5.4 million kWh/year.	42.5–125 lb/hr or 186–548 tpy.

Additionally, the RSCR catalyst may have the potential to emit NH_3 (as NH_3 slip) and generate nitrous oxide if not operated optimally. Catalysts must be disposed of, presenting a cost; however, many catalyst manufacturers provide a system to regenerate or recycle the catalyst reducing the impacts associated with spent catalysts. In addition to these considerations, there are issues associated with the production, transport, storage, and use of NH_3. However, regular handling of NH_3 has reduced the risks associated with its transport, storage, and use.

As with RSCR, there are issues associated with NH_3, electricity, and compressed air for SNCR. Although specific estimates of resources needed to operate SNCR on the Columbia Falls boiler were not available, we have examined estimates presented for a similar source (Roseburg Forest Products) to illustrate the approximate quantity of resources needed to run a SNCR system. Table 181 provides estimates for additional reagent, electricity and steam use.

[288] Plum Creek Revised Response, Table C–4 (Mar. 13, 2012).

[289] Available at: *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

TABLE 181—ADDITIONAL REAGENT, ELECTRICITY AND STEAM REQUIRED FOR SNCR

	Reagent (Urea)	Electricity	Steam
Boiler SNCR System	165 tpy or 69,740 gallons Urea solution/year.	204,108 kWh/year	51.4 lb/hr or 225 tpy.

As with RSCR, some level of NH_3 slip will be present, which is dependent on the amount of reagent injected and the level of control that is desired. Higher levels of control are associated with greater NH_3 slip. Whether urea or NH_3 is used, there are impacts associated with the production, transport, storage, and use of these chemicals. If urea is used, there will be GHG emissions associated with its hydrolysis prior to its use as a NO_X reagent.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We are also taking into account the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. We propose to eliminate the most expensive option (RSCR), based on costs of compliance and the relatively small size of this facility. The less expensive option (SNCR) would reduce emissions by 205 tpy, which equates to approximately an 18.5% reduction in overall emissions of $SO_2 + NO_X$ from the facility, or a reduction of Q/D from 82 to 67. Based on the relatively small size of this facility, the baseline Q/D, and the reduction in Q/D, we propose to find it reasonable to eliminate this option. Therefore, we are proposing to not require any NO_X controls for this planning period.

Line 1 Sander Dust Burners

Step 1: Identify All Available Technologies

The Line 1 sander dust burners do not currently have post-combustion or low NO_X combustion technology. We identified the following technologies to be available: SCR, RSCR, SNCR, SNCR/SCR hybrid, staged combustion, fuel staging, LNB, OFA, LEA, and FGR. SCR, SNCR, LNB, OFA, LEA and FGR were described in our analysis for CELP. RSCR, SNCR/SCR hybrid, staged combustion, and fuel staging were described in our analysis for Plum Creek's Riley Union boiler.

Step 2: Eliminate Technically Infeasible Options

For the Line 1 sander dust burners, PM loadings are too high for a hot/high dust SCR, and temperatures are too cool following the PMCD unless reheat is used. In addition to these issues, the dryer burners are direct contact dryers. Therefore, any NH_3 in the gas stream from a hot/high dust SCR would have the potential to stain or darken the wood product. For these reasons, SCR was not considered further.

The exhaust from the Line 1 sander dust burners acts as a direct contact heat source for the drying processes at the facility. The use of SNCR would require injection of the reagent prior to the dryers introducing NH_3 to the product lines. Contact with NH_3 may result in reduced product quality. NH_3 darkens wood, which would not be acceptable for Plum Creek's light colored stains. Additionally, NH_3 may affect the curing of any formaldehyde-based resins used in the wood products. High levels of NH_3 reduce the cellulosic structure of the wood, allowing it to be permanently shaped; however compressive strength is reduced, which is an important factor for product quality. Space constraints also are a consideration because there is not sufficient residence time at the required temperatures in the exhaust stream prior to the location where the exhaust comes into contact with the wood products; therefore, there is a likelihood that the conversion of the NH_3 reagent may not be sufficiently completed before the exhaust enters the dryers, making product quality a concern (as stated above). For these reasons, SNCR was not considered further.

Because the PM concentrations in the exhaust of the sander dust burners would require the PM controls to precede the catalyst section of the hybrid system, reheat would be required. RSCR is considered to be feasible without firebox/SNCR injection, therefore SNCR/SCR hybrid systems were not considered further.

Fuel staging is not feasible for the Line 1 sander dust burners. The Line 1 sander dust burners have a combustion chamber that is too small to accommodate fuel staging; therefore, fuel staging was not considered further.

Staged combustion is not compatible with the Line 1 sander dust burners. The Line 1 sander dust burners have a combustion chamber that is one-quarter the volume of the Line 2 sander dust burner. Staged combustion techniques increase the volume (or size) of the flame front for a given heat input rate; therefore it would be necessary to reduce the overall heat input of the burners to achieve lower flame temperatures and thereby realize the NO_X reduction achievable with staged combustion techniques. A reduction in the heat rate to the Line 1 sander dust burners would result in insufficient heat being sent into the drying process.

As stated above in the Step 2 discussion of staged combustion, there is insufficient combustion chamber volume to implement LNB design for the Line 1 sander dust burners; therefore, LNB are considered to be technically infeasible for the Line 1 sander dust burners without increasing combustion chamber volume or decreasing the heat input rate (which would affect Plum Creek's ability to successfully operate the wood product dryers). For this reason, LNB was not considered further.

As also discussed above, there is insufficient combustion chamber volume to implement OFA on the Line 1 burners without decreasing the heat input rate. The reduced heat input rate would prevent the dryers from operating as designed. For this reason, OFA was not considered further.

LEA is considered to be technically infeasible for the Line 1 sander dust burners because sander dust suspension burners require high levels of air in order to fluidize the solid fuel. Poor operation of the burners would result with LEA since high excess air conditions are necessary to sustain stable combustion. The Line 1 dryers are all suspension burners, and therefore LEA is considered technically infeasible for these sources.

Because FGR depends on the same conditions as LEA and LEA is considered technically infeasible for the Line 1 sander dust burners, FGR is also considered infeasible for the Line 1 sander dust burners. Additionally, FGR may require additional combustion chamber volume to accommodate the same heat input while maintaining a reduced flame temperature. For these reasons, FGR was not considered further.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Baseline NO_X emissions from the Line 1 sander dust burners are 319 tpy. A summary of emissions projections for RSCR, the only remaining control technology, is provided in Table 182. Further information can be found in the docket.

TABLE 182—SUMMARY OF LINE 1 NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGY

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
RSCR	75	240	79

Factor 1: Costs of Compliance

Table 183 provides a summary of estimated annual costs and cost effectiveness for RSCR.

TABLE 183—SUMMARY OF LINE 1 NO_X REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
[1] RSCR	748,097	3,117

[1] Further information on our cost calculation can be found in the docket in the document titled Reasonable Progress (RP) Four-Factor Analysis of Control Options for Roseburg Forest Products Co./Missoula Particleboard (a similar type source to Plum Creek).

For RSCR, we are adopting the total annual cost for RSCR for the SolaGen sander dust burner at Roseburg Forest Products. This is likely an underestimation of the cost for the Line 1 sander dust burners at Plum Creek, because the Line 1 sander dust burners are smaller than the SolaGen sander dust burner at Roseburg.

Factor 2: Time Necessary for Compliance

RSCR systems for the Line 1 sander dust burners could be operational within eight months to one year.

Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air quality environmental impacts from RSCR were discussed in the analysis for the boiler. Specific reagent, electricity and steam requirements were not calculated for the Line 1 sander dust burners but are expected to be less than what would be needed for the boiler.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We are also taking into account the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. The emissions reductions from the only feasible option (RSCR) would be fairly small (240 tpy), which would result in approximately 21.7% reduction in overall emissions of $SO_2 + NO_X$ for this facility, or a reduction of Q/D from 82 to 64. Based on the costs of compliance, the relatively small size of the facility, and the reduction in Q/D, we think it reasonable to not impose RSCR for this facility. Therefore, we are proposing to not require any NO_X controls on this unit for this planning period.

Line 2 Sander Dust Burner

Step 1: Identify All Available Technologies

The line 2 sander dust burner uses staged combustion to control NO_X. We identified the following technologies to be available: SCR, RSCR, SNCR, SNCR/SCR hybrid, staged combustion, fuel staging, LNB, OFA, LEA, and FGR. SCR, SNCR, LNB, OFA, LEA and FGR were described in our analysis for CELP. RSCR, SNCR/SCR hybrid, staged combustion, and fuel staging were described in our analysis for Plum Creek's boiler.

Step 2: Eliminate Technically Infeasible Options

All of the sander dust burners have the same issues associated with the implementation of SCR as the boiler. PM loadings are too high for a hot/high dust SCR, and temperatures are too cool following PM control unless reheat is used. In addition to these issues, the dryer burners are all direct contact dryers. Therefore, any NH_3 in the gas stream from a hot/high dust SCR would have the potential to stain or darken the wood product. For these reasons, SCR was not considered further.

The exhaust from the Line 2 sander dust burner acts as a direct contact heat source for the drying processes at the facility. Using SNCR on the Line 2 sander dust burner would cause the same product quality issues that were explained in the analysis for the Line 1 sander dust burners. Space constraints are also an issue as explained for the Line 1 sander dust burners. For these reasons, SNCR was not considered further.

As explained in the analysis for the Line 1 sander dust burners, the PM concentrations in the exhaust of the sander dust burners would require the

PM controls to precede the catalyst section of the hybrid system, and so reheat would be required. RSCR is considered to be feasible without firebox/SNCR injection; therefore SNCR/SCR Hybrid systems were not considered further.

Fuel staging is not feasible for the Line 2 sander dust burner. The Line 2 sander dust burner uses staged combustion. Further modification of the combustion chamber would be required to use fuel staging; however, space constraints would make the expansion infeasible. Also, additional NO_X reductions would not likely be realized because the staged combustion design has already reduced thermal NO_X to the extent possible. For these reasons, fuel staging is not considered further.

The Line 2 sander dust burner already uses staged combustion, therefore further staging would not be technically feasible without complete replacement.

LNB (or staged combustion) is a technique that was designed into the Line 2 sander dust burner; therefore, further staging, or LNB configuration was not considered further.

The Line 2 sander dust burner uses staged combustion. Further modification of the combustion chamber would be required to use fuel staging; however, space constraints would make the expansion infeasible. Also, further NO_X reductions would not likely be realized because the staged combustion design has already reduced thermal NO_X to the extent possible. For these reasons, fuel staging is not considered further.

The Line 2 sander dust burner already employs staged combustion; therefore, further staging through the use of OFA is technically infeasible. For this reason, OFA was not considered further.

LEA is considered to be technically infeasible for the Line 2 sander dust burner because sander dust suspension burners require high levels of air in order to fluidize the solid fuel. Poor operation of the burners would result with LEA since high excess air conditions are found under the conditions necessary to sustain stable combustion. The Line 2 dryers are all suspension burners, and therefore LEA is considered technically infeasible for these sources. For these reasons, LEA was not considered further.

FGR is not technically feasible for the Line 2 sander dust burner for the same reasons as were described under the analysis for the Line 1 sander dust burners. Because FGR causes a LEA condition and LEA is considered technically infeasible for the Line 2 sander dust burner, FGR has also been considered to be infeasible for the Line 2 sander dust burner. Also, FGR may require additional combustion chamber volume to accommodate the same heat input while maintaining a reduced flame temperature. For these reasons, FGR was not considered further.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Baseline NO_X emissions from the Line 2 sander dust burner are 200 tpy. A summary of emissions projections for RSCR, the only remaining control technology, is provided in Table 184.

TABLE 184—SUMMARY OF LINE 2 NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGY

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
RSCR	75	150	50

Factor 1: Costs of Compliance

Table 185 provides a summary of estimated annual costs and cost effectiveness for RSCR.

TABLE 185—SUMMARY OF LINE 2 NO_X REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
[1] RSCR	748,000	4,987

[1] Further information on our cost calculation can be found in the docket in the document titled Reasonable Progress (RP) Four-Factor Analysis of Control Options for Roseburg Forest Products Co./Missoula Particleboard (a similar type source to Plum Creek's boiler).

For RSCR, we are adopting the total annual cost for RSCR for the SolaGen sander dust burner at Roseburg Forest Products. This is likely an underestimation of the cost for the Line 2 sander dust burner because the line 2 sander dust burner at Plum Creek is larger than the SolaGen sander dust burner at Roseburg.

Factor 2: Time Necessary for Compliance

RSCR systems for the Line 2 sander dust burner could be operational within eight months to one year.

Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air quality environmental impacts from RSCR were discussed in the analysis for the boiler. Specific reagent, electricity and steam requirements were not calculated for the Line 2 sander dust burner, but are expected to be less than what would be needed for the boiler.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We are also taking into account the size of the facility, the baseline Q/

D of the facility, and the potential reduction in Q/D from the controls. Based on the costs of compliance and the relatively small size of this facility, we find it reasonable to eliminate the only control option (RSCR). Therefore, we are proposing that no additional controls will be required for this planning period.

viii. Roseburg Forest Products

Roseburg Forest Products Company owns and operates a particleboard manufacturing facility in Missoula, Montana. Additional information to support this four factor analysis can be found in the docket.[290] The facility has two production lines, one with a multi-platen batch press (Line 1) and one with a continuous press (Line 2). A pre-dryer is used to reduce the moisture of green wood materials received at the facility. Heat for the pre-dryer is provided by exhaust from a 45 MMBtu/hr SolaGen sander dust burner. There are four final dryers associated with Line 1 and two final dryers associated with Line 2 that produce dried wood furnish for face and core material in the particleboard. Heat input for all six of the final dryers is provided by the combined exhaust of a 50 MMBtu/hr ROEMMC sander dust burner and 55 MMBtu/hr sander dust-fired Babcock & Wilcox boiler, which also provides steam for facility processes.

The Babcock & Wilcox boiler is the oldest of the three sander dust-fired sources at the facility. It is a stoker-type boiler that was installed in 1969. Unlike the other sander dust burners at the facility, the boiler serves the function of producing steam for facility processes in addition to providing heat input to the final dryers. The ROEMMC burner was installed in 1979, although it is a 1978 model burner. The sole purpose of this burner is to provide heat input for the final dryers. The SolaGen sander dust burner was installed in 2006, although it is a 2005 model. The sole purpose of this burner is to provide heat input to the pre-dryer.

PM emissions from the Babcock & Wilcox boiler, ROEMMC burner, and Line 1 and 2 final dryers are controlled by multi-clones at the dryer outlets. PM emissions from the SolaGen burner and pre-dryer are controlled by a cyclone, a wet ESP, and a regenerative thermal oxidizer. As discussed previously in Section V.D.6.b., the contribution from point sources to primary organic aerosols, EC, $PM_{2.5}$ and PM_{10} at Montana Class I areas is very small, and modeling tends to confirm that PM emissions from point sources do not have a very large impact. Therefore, we are proposing that additional controls for PM are not necessary for this planning period.

SO_2 emissions are relatively small (6 tpy of SO_2 for all units combined). Thus, SO_2 emissions from these units are not significant contributors to regional haze and our analysis only considers NO_X. Additional controls for SO_2 will not be considered or required in this planning period. We are therefore considering controls only for NO_X for this planning period.

Babcock & Wilcox Boiler

Step 1: Identify All Available Technologies

The Babcock & Wilcox boiler does not currently have post-combustion controls or low NO_X combustion technology. We identified that the following technologies to be available: SCR, RSCR, SNCR, SNCR/SCR hybrid, staged combustion, fuel staging, LNB, OFA, LEA, and FGR. SCR, SNCR, LNB, OFA, LEA and FGR were described in our analysis for CELP. RSCR, SNCR/SCR hybrid, staged combustion, and fuel staging were described in our analysis for the boiler at Plum Creek Manufacturing.

Step 2: Eliminate Technically Infeasible Options

SCR catalysts may be fouled or plugged by exhaust gas that contains high concentrations of PM, as is the case with the combustion of wood, biomass, or hog fuel. To prevent the premature failure of the catalyst, the PM must be removed from the exhaust stream prior to the SCR. In this case, the exhaust from the PM control equipment will not meet the minimum temperature required for SCR to be effective. In addition to these issues, there is insufficient space prior to the dryers to add both PM controls and SCR. Even if there were space to add both systems, the exhaust from PM controls and SCR would be at a lower temperature, resulting in insufficient heat being sent to the dryers. For these reasons, SCR was not considered further.

The exhaust from all of the units act as direct contact heat sources for the drying processes at the facility. The use of SNCR would require injection of the reagent prior to the dryers, which would introduce NH_3 to the product lines. Roseburg has stated that contact with NH_3 may reduce product quality. For this reason, SNCR was not considered further.

A SNCR/SCR hybrid system also uses a catalyst and thus would experience similar technical difficulties related to catalyst plugging and/or fouling, as described for SCR. If PM controls were retrofitted prior to the dryers to allow the SCR to be operated without reheat, the exhaust from the PM controls would be significantly reduced, resulting in insufficient heat being sent to the dryers. Space constraints and product quality concerns are also issues. For these reasons, a SNCR/SCR hybrid system was not considered further.

Two stable zones of combustion are required for fuel staging. If there is insufficient space, the secondary fuel and combustion zone will impinge on the primary zone having the effect of raising the peak flame temperature and, in turn, increasing NO_X emissions. There is not sufficient room within the boiler to achieve fuel staging while maintaining the necessary heat input to the dryers. The creation of a larger combustion zone within the boiler also has the possibility of causing greater flame impingement on the boiler wall and tubes, which may compromise their integrity and cause premature failure. For these reasons, fuel staging was not considered further.

Staged combustion is considered feasible for the boiler in the form of a new SolaGen-type LNB; however, staged combustion in the form of OFA is considered technically infeasible for the boiler. Suspension burners such as the boiler need high air flow through the fuel-feed auger and burner to suspend and fluidize the solid fuel. Splitting the combustion air to OFA ports would result in poor and perhaps unstable combustion at the burner tip. For this reason, OFA was not considered further.

As with OFA, suspension-type burners, such as the boiler, require high levels of air in order to fluidize the solid fuel. The burners would operate poorly with LEA. For this reason, LEA was not considered further.

FGR is a technique with multiple mechanisms for reducing NO_X, including reducing the available oxygen, since some exhaust gas replaces oxygen rich ambient air. As with LEA, some combustion air must be reduced to accommodate the recirculating flue gas, which may cause the suspension burner to operate improperly. FGR may be applied in some situations, but in order to maintain the necessary heat input in this situation, additional combustion chamber volume would be required to accommodate the volume of the flue gas introduced into the combustion

[290] Reasonable Progress Analysis, Roseburg Forest Products, Missoula Particleboard, Submitted for Roseburg Forest Products by Golder Associates, Inc. (Feb. 2, 2011); Reasonable Progress (RP) Four-Factor Analysis of Control Options for Roseburg Forest Products Co., Missoula Particleboard.

chamber. For these reasons, FGR was not considered further.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

A summary of emissions projections for LNB and RSCR, the only remaining control technologies, are provided in Table 186. At this facility, RSCR would be placed downstream of the wood particle dryers and as a result would control emissions from both the boiler and the ROEMMC sander dust burner. Baseline NO_X emissions from the boiler are 134 tpy. Baseline NO_X emissions from the Line 1 dryers would be from the boiler and ROEMMC sander dust burner combined and are 202 tpy. Baseline NO_X emissions from the Line 2 dryers would be from the boiler and ROEMMC sander dust burner combined and are 92 tpy.

TABLE 186—SUMMARY OF ROSEBURG NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGY

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
LNB	22.2	30	104
RSCR Line 1	75	[1] 151	[1] 51
RSCR Line 2	75	[1] 69	[1] 23

[1] RSCR on the dryers would control emissions from the boiler and the ROEMMC.

LNBs are a form of staged combustion and may be able to achieve 50–70% reductions in NO_X emissions when firing coal, depending on the design or generation of the burner. However, NO_X reductions are highly dependent on the specifics of the burner design, fuel fired, and the operational setting. Roseburg presented a control efficiency for LNB applicable to the boiler of approximately 20%, which was based on information from the LNB vendor. This is not unreasonable considering that biomass produces primarily fuel NO_X rather than thermal NO_X, and LNB primarily reduce the generation of thermal NO_X.

Factor 1: Costs of Compliance

Table 187 provides a summary of estimated annual costs and cost effectiveness for LNB and RSCR.

TABLE 187—SUMMARY OF ROSEBURG NO_X REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
LNB	70,624	2,354
RSCR Line 1	2,261,273	14,975
RSCR Line 2	1,234,469	17,891

For LNB, we are adopting cost figures provided by Roseburg, except that we annualized the capital cost by multiplying the capital cost by a CRF that corresponds to a 7% interest rate and 20-year equipment life (which yields a CRF of 0.0944), as specified in the Office of Management and Budget's Circular A–4, Regulatory Analysis.[291]

Factor 2: Time Necessary for Compliance

EPA found cases in which boilers have been retrofitted with LNB in less than six months. However, this does not take into account variables that affect the ability of a company to have equipment off-line, such as seasonal variations in business that may require Roseburg to postpone retrofit until such time as is appropriate. In this case, we would expect that the LNB can be installed within a maximum of 12 months.

RSCR systems can be operational within eight months to one year.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

LNB would reduce the heat rate that could be sent to the units without increasing the volume of the combustion chamber. That would have the effect of reducing the mass flow rate and heat flux through the dryers. In order to make up for the lost heat it may be possible to add an additional heat source; however, that would use additional fuel, increasing natural resource use. It may be possible to reduce the amount of ambient air mixed into the exhaust prior to the dryers, but this is unlikely because there must be sufficient air flow, in addition to heat, to reduce the moisture content of the product.

RSCR requires the reheat of the flue gas, either through a heat exchanger that utilizes plant waste heat, and/or through direct reheat of the flue gas by additional combustion or electrically powered heating elements. The flue gas at the boiler exhaust is approximately 572 °F, and the temperature of the exhaust of the ROEMMC varies between 700 °F and 1050 °F. These two gas streams then mix with additional ambient air and pass through the Line 1 and Line 2 dryers, further reducing the exhaust gas temperature to 130 °F to 155 °F. In order to reheat the gas stream and operate the RSCR system it is anticipated that the following resources described in Table 188 would be required or consumed.

[291] Available at: *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

TABLE 188—ADDITIONAL AMMONIA, NATURAL GAS, ELECTRICITY AND COMPRESSED AIR FOR RSCR

	Ammonia (NH_3)	Natural gas	Electricity	Compressed air
Line 1 RSCR	433,000 gal/year	9.7 million scf/year	3.6 million kWh/year	7.2 million scf/year
Line 2 RSCR	433,000 gal/year	4.7 million scf/year	1.7 million kWh/year	3.8 million scf/year

Additionally, the RSCR catalyst may have the potential to emit NH_3 (as NH_3 slip) and generate nitrous oxide if not operated optimally. Catalysts must be disposed of, presenting a cost; however, many catalyst manufacturers provide a system to regenerate or recycle the catalyst reducing the impacts associated with spent catalysts. In addition to these considerations, there are issues associated with the production, transport, storage, and use of NH_3. However, regular handling of NH_3 has reduced the risks associated with its transport, storage, and use.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We are also taking into account the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. We propose to eliminate the most expensive options (RSCR on line 1 and line 2), based on costs of compliance and the relatively small size of this facility. The most cost-effective option (LNB) would reduce emissions by only 34 tpy, which equates to approximately a 9.2% reduction in overall emissions of SO_2 + NO_X from the facility, or a reduction of Q/D from 12 to 11. Based on this benefit, the baseline Q/D, and the reduction in Q/D, we find it reasonable to eliminate this option. Therefore, we are proposing to not require any NO_X controls on this unit for this planning period.

ROEMMC Sander Dust Burner

Step 1: Identify All Available Technologies

The ROEMMC sander dust burner does not currently have post combustion controls or low NO_X combustion technology. We identified that the following technologies to be available: SCR, RSCR, SNCR, SNCR/SCR hybrid, staged combustion, fuel staging, LNB, OFA, LEA, and FGR. SCR, SNCR, and LNB, OFA, LEA and FGR were described in our analysis for CELP. RSCR, SNCR/SCR hybrid, staged combustion, and fuel staging were described in our analysis for the boiler at Plum Creek Manufacturing.

Step 2: Eliminate Technically Infeasible Options

SCR was not considered further for the ROEMMC sander dust burner for the same reasons provided for the boiler: Insufficient space for both PM controls (necessary to avoid fouling and plugging) and the SCR catalyst, and insufficient heat from the exhaust to operate the dryers.

RSCRs would be placed downstream of the wood particle dryers. The RSCRs would control emissions from the ROEMMC sander dust burner in addition to the Babcock & Wilcox boiler. This technology was described in the analysis for the boiler; for the same reasons it was considered feasible there, it is considered feasible here.

SNCR was not considered further for the ROEMMC sander dust burner for the same reason provided for the boiler: reduced product quality due to contact with NH_3. A SNCR/SCR hybrid system was also not considered further for the ROEMMC sander dust burner for the same reasons provided for the boiler: lower temperature exhaust from PM controls and the SCR/SNCR hybrid system would provide insufficient heat for the dryers.

Staged combustion techniques increase the volume of the flame front for a given heat input rate. The ROEMMC sander dust burner is small, making it necessary to reduce the overall heat input to levels below what is needed to operate the dryers to achieve staged combustion. For this reason, staged combustion was not considered further.

Fuel staging was not considered further for the same reasons provided for the boiler: Insufficient space to achieve fuel staging while maintaining the necessary heat input the dryers.

LNB designs increase the length of the flame front. In order for the ROEMMC sander dust burner to operate as designed (with a rich and lean zone), the heat input to the burner would need to be decreased so that a smaller, yet longer flame could be created within the same physical space available with the current combustion chamber. The reduced firing rate would have the effect of reducing the necessary heat input below acceptable levels for operating the dryers. For these reasons, LNB was not considered further.

The ROEMMC sander dust burner does not have sufficient space to install OFA ports. In addition to space constraints, suspension burners such as the ROEMMC need high air flow through the fuel feed auger and burner to suspend and fluidize the solid fuel. Splitting the combustion air to OFA ports would result in poor and perhaps unstable combustion at the burner tip. For these reasons, OFA was not considered further.

LEA was not considered further for the ROEMMC sander dust burner for the same reasons provided for the boiler. Suspension-type burners, such as the ROEMMC sander dust burner, require high levels of air in order to fluidize the solid fuel. The burners would operate poorly with LEA.

FGR was not considered further for the ROEMMC sander dust burner for the same reasons provided for the boiler. FGR reduces the available oxygen, since some exhaust gas replaces oxygen rich ambient air. Additionally, FGR may require increased combustion chamber volume to accommodate the same heat input while maintaining a reduced flame temperature. For these reasons, FGR was not considered further.

All technologies identified in Step 1 were eliminated in Step 2; therefore, our analysis for the ROEMMC sander dust burner is complete. We have determined that no additional controls should be imposed on this unit in this planning period.

SolaGen Sander Dust Burner

Step 1: Identify All Available Technologies

The SolaGen sander dust burner currently uses LNB and FGR to control NO_X. We identified that the following technologies to be available: SCR, RSCR, SNCR, SNCR/SCR hybrid, staged combustion, fuel staging, OFA, and LEA. SCR, SNCR, LNB, OFA, LEA and FGR were described in our analysis for

CELP. RSCR, SNCR/SCR hybrid, staged combustion, and fuel staging were described in our analysis for the boiler at Plum Creek Manufacturing.

Step 2: Eliminate Technically Infeasible Options

SCR was not considered further for the SolaGen sander dust burner for the same reasons provided for the boiler. There is insufficient space prior to the pre-dryer to add both PM controls and SCR, and the exhaust from PM controls and SCR would be at a lower temperature resulting in insufficient heat being sent to the pre-dryer.

SNCR was not considered further for the SolaGen sander dust burner for the same reason provided for the boiler: reduced product quality from contact with NH_3. A SNCR/SCR hybrid system was not considered further for the SolaGen sander dust burner for the same reasons provided for the boiler: lower temperature exhaust from PM controls and the SCR/SNCR hybrid system would provide insufficient heat for the pre-dryer.

The SolaGen sander dust burner is a LNB, which is a form of staged combustion; further staging would not be technically feasible for the SolaGen. For this reason, staged combustion was not considered further.

Fuel staging was not considered further for the same reasons provided for the boiler. There is not sufficient room to achieve fuel staging while maintaining the necessary heat input for the pre-dryer.

The SolaGen sander dust burner already utilizes a LNB design, making further excess air infeasible to support stable combustion. For this reason, OFA was not considered further.

LEA was not considered further for the SolaGen sander dust burner for the same reasons provided for the boiler. Suspension-type burners, such as the SolaGen sander dust burner, require high levels of air in order to fluidize the solid fuel. The burners would operate poorly with LEA.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

Baseline NO_X emissions from the SolaGen sander dust burner are 58 tpy. A summary of emissions projections for RSCR, the only remaining control technology, is provided in Table 189.

TABLE 189—SUMMARY OF ROSEBURG NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGY

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
RSCR	75	43	15

Factor 1: Costs of Compliance

Table 190 provides a summary of estimated annual costs for RSCR.

TABLE 190—SUMMARY OF ROSEBURG RSCR REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
RSCR	748,097	17,398

We are adopting cost figures provided by Roseburg, except that we annualized the capital cost by multiplying the capital cost by a CRF that corresponds to a 7% interest rate and 20-year equipment life (which yields a CRF of 0.0944), as specified in the Office of Management and Budget's Circular A–4, Regulatory Analysis.[292]

Factor 2: Time Necessary for Compliance

RSCR systems can be operational within eight months to one year.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

RSCR requires the reheat of the flue gas, either through a heat exchanger that utilizes plant waste heat, and/or through direct reheat of the flue gas by additional combustion or electrically powered heating elements. In order to reheat the gas stream and operate the RSCR system, the following resources described in Table 191 would be consumed.

TABLE 191—ADDITIONAL AMMONIA, NATURAL GAS, ELECTRICITY AND COMPRESSED AIR REQUIRED FOR RSCR

Ammonia (NH_3)	Natural gas	Electricity	Compressed air
304,000 gal/year	2 million scf/year	700,000 kWh/year	1.3 million scf/year

Environmental impacts were described in the analysis for the boiler.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: the cost of compliance; the time necessary for compliance; the

[292] Available at: *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We are also taking into account the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. We find it reasonable to eliminate the only feasible option, RSCR, on the basis of the costs of compliance and the relatively small size of this facility. Therefore, we are proposing that no additional NO_X controls will be required for this planning period.

ix. Smurfit Stone Container

Smurfit Stone Container Enterprises Inc., Missoula Mill (purchased and renamed M2Green Redevelopment LLC Missoula Site on 5/3/11) [293] was determined to be below the threshold of sources subject to BART, but above the threshold for sources subject to further evaluation for RP controls. According to an emissions report from M2Green Redevelopment LLC, the mill was permanently shut down on January 12, 2010 and is no longer operating.[294]

While the current owners have permanently shut down the mill at M2Green Redevelopment LLC, Missoula Site, and it is uncertain whether the mill will resume operations, should the mill resume operations we will revise the FIP as necessary in accordance with regional haze requirements, including the ''reasonable progress'' provisions in 40 CFR 51.308(d)(1).

x. Yellowstone Energy Limited Partnership

Yellowstone Energy Limited Partnership (YELP), in partnership with Billings Generation Incorporated, owns an electric power plant in Billings, Montana.[295] The plant is rated at 65 MW gross output and includes two identical CFB boilers that are fired on petroleum coke and cooker gas; exhaust exits through a common stack. The boilers and emission controls were installed in 1995.

PM emissions are controlled by two fabric filter baghouses at the common stack that is designed to achieve greater than 99% control of particulates.[296] As discussed previously in Section V.D.6.b., the contribution from point sources to primary organic aerosols, EC, $PM_{2.5}$ at Montana Class I areas is very small, and modeling tends to confirm that PM emissions from point sources do not have a very large impact. Therefore, we are proposing that additional controls for PM are not necessary for this planning period.

SO_2

Step 1: Identify All Available Technologies

We identified that the following technologies to be available: limestone injection process upgrade, a SDA, DSI, a CDS, HAR, a wet lime scrubber, a wet limestone scrubber, and/or a dual alkali scrubber.

YELP currently controls SO_2 emissions using limestone injection. Crushed limestone is injected with the petroleum coke prior to its combustion in the two CFB boilers. When limestone is heated to 1550 °F, it releases CO_2 and forms lime (CaO), which subsequently reacts with the SO_2 in the combustion gas to form calcium sulfates and calcium sulfites. The calcium compounds are removed as PM by the baghouse. Depending on the fuel fired in the boilers and the total heat input, YELP must achieve, under a Montana operating permit, 70% to 90% reduction of SO_2 emissions. YELP states that, during 2008 through 2009, SO_2 reduction averaged 95%. Increasing the limestone injection rate beyond current levels could theoretically result in a modest increase in SO_2 control.

SDAs were described in our analysis for CELP. SDAs have demonstrated the ability to achieve 90% to 94% SO_2 reduction. SDA plus limestone injection can achieve between 98% and 99% SO_2 reduction.[297] Due to the high degree of SO_2 control efficiency already achieved by limestone injection at this facility (95%), we have used 80% control efficiency for SDA in this analysis, downstream of limestone injection.

DSI was described in our BART analysis for Corette. SO_2 control efficiencies for DSI systems by themselves (not downstream of limestone injection systems) are approximately 50%, but if the sorbent is hydrated lime, then 80% or greater removal can be achieved. These systems are commonly called lime spray dryers.

A description of a CDS was provided in our analysis for CELP. A CDS can achieve removal efficiency similar to that achieved by SDA on CFB boilers.[298]

The HAR process was described in our analysis for CELP. HAR downstream of a CFB boiler that utilizes limestone injection can reduce the remaining SO_2 by about 80%.[299]

A general description of wet lime scrubbing was provided in our BART analysis for Ash Grove.

Wet lime and wet limestone scrubbers involve spraying alkaline slurry into the exhaust gas to react with SO_2 in the flue gas. Insoluble salts are formed in the chemical reaction that occurs in the scrubber and the salts are removed as a solid waste by-product. Wet lime and limestone scrubbers are very similar, but the type of additive used differs (lime or limestone). The use of limestone ($CaCO_3$) instead of lime requires different feed preparation equipment and a higher liquid-to-gas ratio. The higher liquid-to-gas ratio typically requires a larger absorbing unit. The limestone slurry process also requires a ball mill to crush the limestone feed. Wet lime and limestone scrubbers have been demonstrated to achieve greater than 99% control efficiency.[300]

Dual-alkali scrubbers use a sodium-based alkali solution to remove SO_2 from the combustion exhaust gas. The process uses both sodium-based and calcium-based compounds. The sodium-based reagents absorb SO_2 from the exhaust gas, and the calcium-based solution (lime or limestone) regenerates the spent liquor. Calcium sulfites and sulfates are precipitated and discarded as sludge, and the regenerated sodium solution is returned to the absorber loop. The dual-alkali process requires lower liquid-to-gas ratios than scrubbing with lime or limestone. The reduced liquid-to-gas ratios generally mean smaller reaction units; however, additional regeneration and sludge processing equipment is necessary. A sodium-based scrubbing solution, typically consisting of a mixture of sodium hydroxide, sodium carbonates, and sodium sulfite, is an efficient SO_2 control reagent. However, the process generates a sludge that can create material handling and disposal issues. The control efficiency is similar to the wet lime/limestone scrubbers at approximately 95% or greater.

Step 2: Eliminate Technically Infeasible Options

The current limestone injection system is operating at or near its maximum capacity. The boiler feed rates are approximately 740 tons/day of petroleum coke and 415 tons/day of limestone. Increasing limestone injection beyond the current levels would result in plugging of the injection

[293] See *http://www.greeninvgroup.com/news/news-release-missoula-announcement.html.*

[294] M2Green Redevelopment LLC Quarterly Excess Emissions Report—Third Quarter 2011 (11/1/2011).

[295] All information found within this section can be found in the corresponding report in the docket.

[296] Response to Additional Reasonable Progress Information for the Yellowstone Energy Limited Partnership Facility Pursuant to Section 114(a) of the CAA (42 U.S.C. Section 7414(A)) Prepared for Billings Generation, Inc. (''YELP Additional Response''), p. 2–1 February 24, 2011.

[297] Deseret Bonanza SOB, p. 92.

[298] *Id.*

[299] *Id.*, p. 93.

[300] Deseret Bonanza SOB, p. 94.

lines, and increased bed ash production, which can reduce combustion efficiency, and increased particulate loading to the baghouses. Therefore, increasing limestone injection beyond its current level would require major upgrades to the limestone feeding system and the baghouses.[301] Only modest increases in SO_2 removal efficiency, if any, would be expected with this scenario, compared to add-on SO_2 control systems discussed below. Therefore, a limestone injection process upgrade is eliminated from further consideration.

CDS systems result in high particulate loading to the unit's particulate control device. Because of the high particulate loading, the pressure drop across a fabric filter would be unacceptable; therefore, ESPs are generally used for particulate control. YELP has two high efficiency fabric filters (baghouses) in place. Based on limited technical data from non-comparable applications and engineering judgment, we are determining that CDS is not technically feasible for this facility.[302] Therefore, CDS is eliminated from further consideration.

A DSI system is not practical for use in a CFB boiler such as YELP, where limestone injection is already being used upstream in the boiler for SO_2 control. With limestone injection, the CFB boiler flue gas already contains excess unreacted lime. Fly ash containing this unreacted lime is reinjected back into the CFB boiler combustion bed, as part of the boiler operating design. A DSI system would simply add additional unreacted lime to the flue gas and would achieve little, if any, additional SO_2 control.[303] If used instead of limestone injection (the only practical way it might be used), DSI would achieve less control efficiency (50%) than the limestone injection system already being used (70 to 90%). Therefore, DSI is eliminated from further consideration.

Regarding wet scrubbing, there is limited area to install additional SO_2 controls that would require high quantities of water and dewatering ponds. The wet FGD scrubber systems with the higher water requirements (wet lime scrubber, wet limestone scrubber, and dual alkali wet scrubber) would require an on-site dewatering pond or an additional landfill to dispose of scrubber sludge. Due to the limited available space, its proximity to the Yellowstone River and limited water availability for these controls,[304] we consider these technologies technically infeasible and do not evaluate them further.

The remaining technically feasible SO_2 control options for YELP are SDA and HAR.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

Baseline NO_X emissions from YELP are 1,826 tpy. A summary of emissions projections for the various control options is provided in Table 192. Since limestone injection is already in use at the YELP facility, the control efficiencies and emissions reductions shown below are those that might be achieved beyond the control already being achieved by the existing limestone injection system.

TABLE 192—SUMMARY OF YELP SO_2 REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGIES

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
SDA	80	1,461	365
HAR	50	913	913

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of compliance

Table 193 provides a summary of estimated annual costs for the various control options. All costs shown are for the two boilers combined.

TABLE 193—SUMMARY OF YELP SO_2 REASONABLE PROGRESS COST ANALYSIS AS RECALCULATED BY EPA

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
SDA with baghouse replacement	6,237,065	4,211
SDA without baghouse replacement	4,709,504	3,182
HAR with baghouse replacement	4,660,376	5,104
HAR without baghouse replacement	3,132,815	3,431

We have relied on the control costs provided by YELP,[305] with two exceptions. First, we calculated the annual cost of capital using 7% annual interest rate and a 20-year equipment life (which yields a CRF of 0.0944), as specified in the Office of Management and Budget's Circular A–4 Regulatory Analysis.[306] Second, we calculated the cost of SDA and HAR in two ways: (1) With baghouse replacement, and (2) without baghouse replacement, see Table 193 above.

Factor 2: Time Necessary for Compliance

We have relied on YELP's estimates that the time necessary to complete the modifications to the two boilers to accommodate SDA or HAR, without replacing the baghouses, would be

[301] YELP Additional Response, p. 2–2.
[302] Deseret Bonanza SOB, p. 92.
[303] *Id.*, p. 93.
[304] YELP Additional Response, p. 2–5.
[305] *Id.*, p. 7–3.
[306] Available at: *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

approximately one year and that a boiler outage of approximate two to three months per boiler would be necessary to perform the installation of either system. The installation of the controls would need to be staggered to allow one boiler to remain in operation while the retrofits are applied to the other boiler. YELP states that complete replacement or major modifications to the existing baghouses would be necessary, however, the company does not explain why the existing baghouses would need to be replaced or modified to accommodate SDA or HAR.[307]

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

Wet FGD systems are estimated to consume 1% to 2.5% of the total electric generation of the plant and can consume approximately 40% more than dry FGD systems (SDA). Electricity requirements for a HAR system are less than FGD systems. DSI systems are estimated to consume 0.1% to 0.5% of the total plant generation.[308] For reasons explained above, wet FGD systems and DSI systems have already been eliminated as technically infeasible.

SO_2 controls would result in increased ash production at the YELP facility. Boiler ash is currently either sent to a landfill or sold for beneficial use, such as oil well reclamation. Changes in ash properties due to increased calcium sulfates and calcium sulfites could result in the ash being no longer suitable to be sold for beneficial uses. If the ash properties were to change such that the ash could no longer be sold for beneficial use, the loss of this market would cost approximately $2,300,000 per year at the current ash value and production rates (approximately 170,000 tons of ash per year). The loss of this market could also result in the company having to dispose of the ash at its current landfill, which is approximately 80 miles from the plant. The cost to dispose of the ash would be approximately $96,000 per year. The total cost from the loss of the beneficial use market and the increase in ash disposal costs would be a total of $2,400,000 per year.[309] This potential cost has not been included in the cost described above, as it is only speculative, being based on an undetermined potential future change in ash properties.

As described above, wet FGD scrubber systems with the higher water requirements (Wet Lime Scrubber, Wet Limestone Scrubber, and Dual Alkali Wet Scrubber) would require construction of an on-site dewatering pond or an additional landfill to dispose of scrubber sludge.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: the cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We are also taking into account the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. Given the cost of $3,182 per ton of SO_2 (at a minimum) for the most cost-effective option (SDA), the relatively small size of YELP, and the small baseline Q/D of 14, we find it reasonable to not impose any of the SO_2 control options. Therefore, we are proposing that no additional controls will be required for this planning period.

NO_X

Currently, there are no NO_X controls at the YELP facility.

Step 1: Identify All Available Technologies

We identified that the following technologies to be available: SCR, SNCR, LEA, FGR, OFA, LNB, non-thermal plasma reactor, and carbon injection into the combustion chamber.

SCR, SNCR, LNB, LEA, OFA, FGR, non-thermal plasma reactor, and carbon injection into the combustion chamber were described in our analysis for CELP.

The temperature range for proper operation of an SCR is between 480 °F and 800 °F. Many of the CFBs in the United States have baghouses for particulate control. The normal maximum allowable temperature for a baghouse is 400 °F.

Therefore, on some installations, RSCR is installed. RSCRs are expensive to install and expensive to operate, because an RSCR requires the use of burners to heat up the flue gas stream in order for the NO_X capture to occur. This is often an efficiency decrease for the boiler, significant increase in operating cost, and often not a practical solution. For this reason, RSCR was not evaluated as a control option for YELP. Instead, high dust SCR was evaluated.

Step 2: Eliminate Technically Infeasible Options

LEA, FGR, and OFA are typically used on Pulverized Coal (PC) units and cannot be used on CFB boilers due to air needed to fluidize the bed.[310] While LEA may have substantial effect on NO_X emissions at PC boilers, it has much less effect on NO_X emissions at combustion sources such as CFBs that operate at low combustion temperatures. FGR reduces NO_X formation by reducing peak flame temperature and is ineffective on combustion sources such as CFBs that already operate at low combustion temperatures. For these reasons, LEA, FGR and OFA are eliminated from further consideration.

LNBs are typically used on PC units and cannot be used on CFB boilers because the combustion occurs within the fluidized bed.[311] CFB boilers do not use burners during normal operation. Therefore, LNBs are eliminated from further consideration.

While a non-thermal plasma reactor may have practical potential for application to coal-fired CFB boilers as a technology transfer option at Step 1 of the analysis, it is not known to be commercially available for CFB boilers.[312] Therefore, a non-thermal plasma reactor is eliminated from further consideration.

Although carbon injection is an emerging technology used to reduce mercury emissions, it has not been used anywhere to control NO_X. Therefore, it is eliminated from further consideration.

The remaining technically feasible NO_X control options for YELP are HDSCR and SNCR.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

Baseline NO_X emissions from YELP are 396 tpy. A summary of emissions projections for the various control options is provided in Table 194.

[307] YELP Additional Response, p. 3–1.
[308] *Id.*, p. 4–2.
[309] *Id.*
[310] *Id.*
[311] *Id.*
[312] Deseret Bonanza SOB, pp. 46, 48.

TABLE 194—SUMMARY OF YELP NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGIES

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
HDSCR	80	317	79
SNCR	50	198	198

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

Table 195 provides a summary of estimated annual costs for the various control options.

TABLE 195—SUMMARY OF YELP NO_X REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
HDSCR	3,883,020	12,249
SNCR	529,810	2,689

We have relied on the NO_X control costs provided by YELP,[313] with one exception. We calculated the annual cost of capital using a 7% annual interest rate and 20-year equipment life (which yields a CRF of 0.0944), as specified in the Office of Management and Budget's Circular A–4, Regulatory Analysis.[314]

Factor 2: Time Necessary for Compliance

We have relied on YELP's estimates that HDSCR would take approximately 26 months to install and that SNCR would take 24 to 30 weeks to install.[315]

Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance

The energy impacts from SNCR are expected to be minimal. SNCR is not expected to cause a loss of power output from the facility. SCR, however, could cause significant backpressure on the boiler, leading to lost boiler efficiency and, thus, a loss of power production. If LDSCR was to be installed instead of HDSCR, YELP would be subject to the additional cost of reheating the exhaust gas.

Regarding other non-air quality environmental impacts of compliance, SCRs can contribute to airheater fouling from the formation of ammonium sulfate. Airheater fouling could reduce unit efficiency, increase flue gas velocities in the airheater, cause corrosion, and erosion. Catalyst replacement can lengthen boiler outages, especially in retrofit installations, where space and access is limited. This is a retrofit installation in a high dust environment, thus fouling is likely, which could lead to unplanned outages or less time between planned outages. On some installations, catalyst life is short and SCRs have fouled in high dust environments. For both SCR and SNCR, the storage of on-site NH_3 could pose a risk from potential releases to the environment. An additional concern is the loss of NH_3, or ''slip'' into the emissions stream from the facility. This ''slip'' contributes another pollutant to the environment, which has been implicated as a precursor to $PM_{2.5}$ formation.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the source. For the more expensive option (SCR), we have concluded that the costs per ton of pollutant reduced are excessive for this facility. The less expensive option (SNCR) would reduce emissions by 198 tpy, which equates to approximately an 8.9% reduction in overall emissions of SO_2 + NO_X from this facility, or a reduction of Q/D from 14 to 13. Given the small size of the facility, the baseline Q/D, and the potential reduction in Q/D, we find it reasonable to eliminate this option. Therefore, we are proposing to not require any NO_X controls on this unit for this planning period.

d. Establishment of the Reasonable Progress Goal

40 CFR 51.308(d)(1) of the Regional Haze Rule requires states to ''establish goals (in deciviews) that provide for Reasonable Progress towards achieving natural visibility conditions'' for each Class I area of the state. These RPGs 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 RPGs for the first planning period are goals for the year 2018.

Based on (1) the results of the WRAP CMAQ modeling, and (2) the results of the four-factor analysis of Montana point sources, we established RPGs for the most impaired days for all of Montana's Class I areas, as identified in Table 196 below. Also shown in Table 197 is a comparison of the RPGs to the URP for Montana Class I areas. The RPGs for the 20% worst days fall short

[313] YELP Additional Response, Appendix A.

[314] Available at: *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

[315] YELP Additional Response, p. 3–1.

of the URP by the amounts shown in the table.

TABLE 196—COMPARISON OF REASONABLE PROGRESS GOALS TO UNIFORM RATE OF PROGRESS ON MOST IMPAIRED DAYS FOR MONTANA CLASS I AREAS

Montana class I area	Visibility conditions on 20% worst days (deciview)			Percentage of URP achieved (%)
	Average for 20% worst days (baseline 2000–2004)	2018 URP goal	RPG (WRAP projection)	
Anaconda-Pintler WA	13.41	12.02	12.94	34
Bob Marshall WA	14.48	12.91	13.83	41
Cabinet Mountains WA	14.09	12.56	13.31	51
Gates of the Mountains WA	11.29	10.15	10.82	41
Glacier NP	22.26	19.21	21.48	26
Medicine Lake WA	17.72	15.42	17.36	16
Mission Mountain WA	14.48	12.91	13.83	41
Red Rock Lakes WA	11.76	10.52	11.23	43
Scapegoat WA	14.48	12.91	13.83	41
Selway-Bitterroot WA	13.41	12.02	12.94	34
U.L. Bend WA	15.14	13.51	14.85	18
Yellowstone NP	11.76	10.52	11.23	43

Our RPGs for each Class I area for 2018 for the 20% worst days represents the improvement shown in Table 197. Our RPGs establish a slower rate of progress than the URP. The number of years necessary to attain natural conditions was calculated by dividing the amount of improvement needed by the rate of progress established by the RPGs. Table 197 shows the number of years it would take to attain natural conditions if visibility improvement continues at the rate of progress established by the RPGs.

TABLE 197—NUMBER OF YEARS TO REACH NATURAL CONDITIONS FOR MONTANA CLASS I AREAS

Montana class I area	2064 natural conditions (deciview)	Average for 20% worst days (Baseline 2000–2004)	Improvement needed (deciview)	RPG Rate of improvement (deciview/year)	Number of years to reach natural conditions
Anaconda-Pintler WA	7.43	13.41	5.98	0.03	204
Bob Marshall WA	7.73	14.48	6.75	0.04	166
Cabinet Mountains WA	7.52	14.09	6.57	0.05	135
Gates of the Mountains WA	6.38	11.29	4.91	0.03	167
Glacier NP	9.18	22.26	13.08	0.05	268
Medicine Lake WA	7.89	17.72	9.83	0.02	437
Mission Mountain WA	7.73	14.48	6.75	0.04	166
Red Rock Lakes WA	6.44	11.76	5.32	0.03	161
Scapegoat WA	7.73	14.48	6.75	0.04	166
Selway-Bitterroot WA	7.43	13.41	5.98	0.03	204
U.L. Bend WA	8.16	15.14	6.98	0.02	385
Yellowstone NP	6.44	11.76	5.32	0.03	161

Table 198 provides a comparison of our RPGs for Montana to baseline conditions on the least impaired days. This comparison demonstrates that our RPGs will result in no degradation in visibility conditions in the first planning period.

TABLE 198—COMPARISON OF REASONABLE PROGRESS GOALS TO BASELINE CONDITIONS ON LEAST IMPAIRED DAYS FOR MONTANA CLASS I AREAS

Montana class I area	Visibility conditions on 20% best days (deciview)		Achieved "No degradation" (Y/N)
	Average for 20% best days (Baseline 2000–2004)	RPG (WRAP projection)	
Anaconda-Pintler WA	2.58	2.48	Y
Bob Marshall WA	3.85	3.60	Y
Cabinet Mountains WA	3.62	3.27	Y
Gates of the Mountains WA	1.71	1.54	Y

TABLE 198—COMPARISON OF REASONABLE PROGRESS GOALS TO BASELINE CONDITIONS ON LEAST IMPAIRED DAYS FOR MONTANA CLASS I AREAS—Continued

Montana class I area	Visibility conditions on 20% best days (deciview)		Achieved "No degradation" (Y/N)
	Average for 20% best days (Baseline 2000–2004)	RPG (WRAP projection)	
Glacier NP	7.22	6.92	Y
Medicine Lake WA	7.26	7.11	Y
Mission Mountain WA	3.85	3.60	Y
Red Rock Lakes WA	2.58	2.36	Y
Scapegoat WA	3.85	3.60	Y
Selway-Bitterroot WA	2.58	2.48	Y
U.L. Bend WA	4.75	4.57	Y
Yellowstone NP	2.58	2.36	Y

The Regional Haze Rule states that if we establish a RPG that provides for a slower rate of improvement in visibility than the rate that would be needed to attain natural conditions by 2064, we must demonstrate that the rate of progress for the implementation plan to attain natural conditions by 2064 is not reasonable; and that the progress goal we adopt is reasonable. 40 CFR 51.308(d)(1)(B)(ii).

We are proposing that the RPGs we established for the Montana Class I areas are reasonable, and that it is not reasonable to achieve the glide path in 2018, for the following reasons:

1. Findings from our four-factor analyses resulted in limited opportunities for reasonable controls for point sources.

2. As described previously in section V.D.2., significant visibility impairment is caused by non-anthropogenic sources in and outside Montana.

We could not re-run the WRAP modeling, but anticipate that the additional controls would result in an increase in visibility improvement during the 20% worst days and the 20% best days. As noted in our analyses, many of our proposed controls would result in significant incremental visibility benefits when modeled against natural background. We anticipate that this would translate into some measurable improvement if modeled on the 20% worst days as well. We are confident that this improvement would not be sufficient to achieve the URP at Montana Class I areas.

For purposes of this action, we are proposing RPGs that are consistent with the additional controls we are proposing. While we would prefer to quantify the RPGs, we note that the RPGs themselves are not enforceable values. The more critical elements of our FIP are the enforceable emissions limits we are proposing.

e. Reasonable Progress Consultation

In accordance with 40 CFR 51.308(d)(3)(i) and (ii), each state that causes or contributes to impairment in a Class I area in another state or states is required to consult with other states and demonstrate that it has included in its SIP all measures necessary to obtain its share of the emission reductions needed to meet the progress goals for the Class I area. If the state has participated in a regional planning process, the state must ensure it has included all measures needed to achieve its apportionment of emission reduction obligations agreed upon through that process.

In this case, where EPA is promulgating a FIP, we take on the responsibilities of the state. We propose that we have met the requirement for consultation with other states through our participation in the WRAP process. Through this processes, we worked with neighboring states, and relied on the technical tools, policy documents, and other products that all western states used to develop their regional haze plans. The WRAP Implementation Work Group was one of the primary collaboration mechanisms. Discussions with neighboring states included the review of major contributing sources of air pollution, as documented in numerous WRAP reports and projects. The focus of this review process was interstate transport of emissions, major sources believed to be contributing, and whether any mitigation measures were needed. All the states relied upon similar emission inventories, results from source apportionment studies and BART modeling, review of IMPROVE monitoring data, existing state smoke management programs, and other information in assessing the extent to which each state contributes to visibility impairment other states' Class I areas.

The Regional Haze Rule at 40 CFR 51.308(d)(3)(ii) requires a state to demonstrate that its regional haze plan includes all measures necessary to obtain its fair share of emission reductions needed to meet RPGs. Based on the consultation described above, we identified no major contributions that supported developing new interstate strategies, mitigation measures, or emission reduction obligations. Both EPA and neighboring states agreed that the implementation of BART and other existing measures in state regional haze plans were sufficient for the states to meet the RPGs for their Class I areas, and that future consultation would address any new strategies or measures needed.

f. Mandatory Long-Term Strategy Requirements

40 CFR 51.308(d)(3)(v) requires that we, at a minimum, consider certain factors in developing our LTS (the LTS factors). These are: (a) Emission reductions due to ongoing air pollution control programs, including measures to address RAVI; (b) measures to mitigate the impacts of construction activities; (c) emissions limitations and schedules for compliance to achieve the RPG; (d) source retirement and replacement schedules; (e) smoke management techniques for agricultural and forestry management purposes including plans as 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 LTS.

i. Reductions Due to Ongoing Air Pollution Programs

In addition to our BART determinations, our LTS incorporates emission reductions due to a number of ongoing air pollution control programs.

a. Prevention of Significant Deterioration/New Source Review Rules

The two primary regulatory tools for addressing visibility impairment from industrial sources are BART and the PSD New Source Review rules. The PSD rules protect visibility in Class I areas from new industrial sources and major changes to existing sources. Title 17, Chapter 8 of the ARM contain requirements for visibility impact assessment and mitigation associated with emissions from new and modified major stationary sources. A primary responsibility of Montana under these rules is visibility protection. ARM 17.8.1106 requires an owner or operator of a major source or major modification to demonstrate that the emissions will not cause or contribute to adverse impact on a Class I area or the Department shall not issue a permit. ARM 17.8.1107 describes the modeling methods.

b. Montana's Phase I Visibility Protection Program

Montana's Visibility SIP was approved as meeting the requirements of 40 CFR 51.305 (Monitoring for RAVI) and 40 CFR 51.307 (New Source Review) on June 6, 1986 (51 FR 20646). On February 17, 2012, Montana submitted a revised Visibility SIP, which as explained in the submittal, includes administrative updates to rule citations, board affiliation, and grammar/punctuation edits to these sections.

EPA will act on the revisions to the sections addressing monitoring for RAVI, new source review, and other sections in a future action.

c. On-going Implementation of State and Federal Mobile Source Regulations

Mobile source NO_X and SO_2 emissions are expected to decrease in Montana from 2002 to 2018.[316] This reduction will result from numerous ''on the books'' federal mobile source regulations described below. This trend is expected to provide significant visibility benefits. Beginning in 2006, EPA mandated new standards for on-road (highway) diesel fuel, known as ultra-low sulfur diesel. This regulation dropped the sulfur content of diesel fuel from 500 ppm to 15 ppm. Ultra-low sulfur diesel fuel enables the use of cleaner technology diesel engines and vehicles with advanced emissions control devices, resulting in significantly lower emissions.

Diesel fuel intended for locomotive, marine, and non-road (farming and construction) engines and equipment was required to meet a low sulfur diesel fuel maximum specification of 500 ppm sulfur in 2007 (down from 5000 ppm). By 2010, the ultra-low sulfur diesel fuel standard of 15 ppm sulfur applied to all non-road diesel fuel. Locomotive and marine diesel fuel will be required to meet the ultra-low sulfur diesel standard beginning in 2012, resulting in further reductions of diesel emissions.

ii. Measures to Mitigate the Impacts of Construction Activities

In developing our LTS, we have considered the impact of construction activities. Based on our general knowledge of construction activity in the State, and without conducting extensive research on the contribution of emissions from construction activities to visibility impairment in Montana Class I areas, we propose to find that current State regulations adequately address construction activities because the regulations already require controls for these sources. Current rules addressing impacts from construction activities in Montana include ARM 17.8.308, which regulates fugitive dust emissions. The rule requires that ''no person shall operate a construction site or demolition project unless reasonable precautions are taken to control emissions of airborne particulate matter.'' The SIP rule also requires that ''[s]uch emissions of airborne particulate matter from any stationary source shall not exhibit an opacity of 20% or greater averaged over six consecutive minutes.'' Additionally, emissions from vehicles at construction site are expected to decrease due to on-going implementation of federal mobile source regulations. ARM 18.8.743 requires permits for asphalt concrete plants, mineral crushers, and mineral screens that have a potential to emit that is greater than 15 tpy.

iii. Emission Limitations and Schedules for Compliance

For those sources subject to BART: Ash Grove Cement Company; PPL Montana, LLC Colstrip Steam Electric Station (Unit 1 and Unit 2); Holcim (US), Inc.; and PPL Montana, LLC JE Corette Steam Electric Station, we have included proposed emission limits and schedules of compliance in regulatory text at the end of this proposal.

As described earlier in Section V.C.3.b.iii, we are proposing that we make a BART determination in the future for CFAC if the sources at that facility begin operating. Additionally, we also are proposing that those sources at CFAC will be required to implement that determination within five years of our final FIP for this action.

For the source that is subject to additional controls for RP requirements, Devon, we have included proposed emission limits and schedules of compliance in regulatory text at the end of this proposal.

We are proposing to determine whether additional controls will be required for Green Investment Group, Inc. (previously owned by Smurfit Stone Container Enterprises Inc.) if the sources at that facility begin operating. We also are proposing that those sources will be required to implement any additional controls that are required by those determinations within this planning period. The proposed schedules for implementation of additional controls for this source is identified within the four factor analyses for this source.

iv. Sources Retirement and Replacement Schedules

Even though the sources at CFAC and Green Investment Group Inc. are not currently operating, we are not relying on those source retirements or replacements in the LTS. Replacement of existing facilities will be managed according to Montana's existing PSD program. The 2018 modeling that WRAP conducted included one new power plant in Montana that is unlikely to be built.[317] Construction of new power plants or replacement of existing plants prior to 2018 is unlikely.

v. Agricultural and Forestry Smoke Management Techniques

We are proposing to use the WRAP's estimates of fire emissions in our analysis for Montana. Table 199, below, shows WRAP's estimate of emissions from fire in Montana for the 2000–2004 baseline period.

[316] WRAP TSD. and Final Report, WRAP Mobile Source Emission Inventories Updated, dated May 2006.

[317] Email from Debbie Skibicki to Vanessa Hinkle dated January 4, 2012 regarding Roundup Power.

TABLE 199—ANNUAL AVERAGE EMISSIONS FROM FIRE (2000–2004) (TONS/YEAR)

Source	$PM_{2.5}$	PM_{10}	NO_X	SO_2	OC	EC
Natural	2,911	8,496	13,770	4,634	38,324	7,743
Anthropogenic	279	713	1,513	500	3,745	759
Total	3,190	9,209	15,283	5,134	42,069	8,502

A more detailed description of the inventories can be found in the docket.[318] 40 CFR 308(d)(3)(v)(E) of the Regional Haze Rule requires the LTS to address smoke management techniques for agricultural and forestry burning. These two sources generally have a very small contribution to visibility impairment in Montana Class I areas. Much of these fire emissions are from wildfires, which fluctuate significantly from year to year. The following paragraph summarizes source apportionment analyses conducted by the WRAP.

As described previously in Sections V.D.6.b., most of the emissions from fire are from wildfires which fluctuate significantly from year to year. Anthropogenic fire contributes 8% to primary organic aerosol emissions, 6% to EC emissions, less than 1% to $PM_{2.5}$ emissions, less than 1% to PM_{10} emissions, 1% to SO_2 emissions, and less than 1% to NO_X emissions. Natural fire contributes 80% to primary organic aerosol emissions, 65% to EC emissions, 4% to $PM_{2.5}$ emissions, 1% to PM_{10} emissions, 9% to SO_2 emissions, and 6% to NO_X emissions. As described previously in Section V.D.2., OC contributes 15% to 64%, EC contributes 4% to 8%, fine particulate contributes 1% to 7%, coarse particulate contributes 4% to 8%, SO_2 contributes 8% to 28%, and NO_X contributes 3% to 27% of the total light extinction to Montana Class I areas.

40 CFR 308(d)(3)(v)(E) of the Regional Haze Rule requires states to consider smoke management techniques for agricultural and forestry burning in their LTS. We are proposing to approve amendments to Montana's existing smoking management program that will ensure that the State's program meets the Regional Haze Rule requirement.

Montana's existing smoke management program regulates major and minor sources of open burning; and the State operates a year round open burning program as well as issues air quality open burning permits for specific types of open burning.[319] On February 17, 2012, Montana submitted a revised Montana Visibility Plan (Plan) that contained revisions to the smoke management program. As described in Montana's ''Explanation of Proposed Action'' the revised Plan ''includes a reference to BACT as the current visibility mitigation measure for open burning administered through the Department's open burning permit program''. The revised Plan requires Montana to consider the visibility impact of smoke on the mandatory federal class I areas when developing, issuing or conditioning permits and when making dispersion forecast recommendations through the implementation of Title 17, Chapter 8, Subchapter 6, Open Burning. These revisions appear in the paragraph of the Plan titled ''Smoke Management''.[320] We are proposing that to approve the revisions to this paragraph titled ''Smoke Management'' as meeting the requirement in 40 CFR 308(d)(3)(v)(E) because the Plan controls emissions from these sources by requiring BACT and takes into consideration the visibility impacts on the mandatory class I areas. We will take action in a future notice on the additional revisions in the Montana Visibility Plan, which as explained in the State's February 17, 2012 submittal include administrative updates to rule citations, board affiliation, and grammar/punctuation edits.

vi. Enforceability of Montana's Measures

40 CFR 51.308(d)(3)(v)(F) of the Regional Haze Rule requires us to ensure that emission limitations and control measures used to meet RPGs are enforceable. In addition to what is required by the Regional Haze Rule, general FIP requirements mandate that the FIP must also include adequate monitoring, recordkeeping, and reporting requirements for the regional haze emission limits and requirements. See CAA section 110(a). As noted, we are proposing specific BART and other emission limits and compliance schedules. For SO_2 and NO_X limits, we are proposing to require the use of CEMS that must be operated and maintained in accordance with relevant EPA regulations, in particular, 40 CFR part 75. For PM limits, we are requiring regular testing. We are proposing to require that relevant records be kept for five years, and that sources report excess emissions on a quarterly basis.

In addition to these requirements, various requirements that are relevant to regional haze are codified in Montana's regulations, including Montana's PSD and other provisions mentioned above.

vii. 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.4 above.

E. Coordination of RAVI and Regional Haze Requirements

Our visibility regulations direct states to coordinate their RAVI LTS and monitoring provisions with those for regional haze, as explained in section IV.G, 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

[318] WRAP TSD; Development of 2000–04 Baseline Period and 2018 Projection Year Emission Inventories, FINAL dated May 2007; Emissions Overview, for which WRAP did not include a date; 2002 Planning Simulation Version D Specification Sheet for which WRAP did not include a date; 1996 Fire Emission Inventory dated December 2002. The actual inventories can be found in the docket in the spreadsheets with the following title: 02d Area Source Inventory.

[319] There are several key elements of Montana's existing smoke management program, which include: (1) Smoke is monitored in Montana (*http://www.satguard.com/usfs4/realtime/MT.asp*); (2) the open burning SIP regulations require best available control technology (BACT) as the visibility mitigation measure for open burning administered through MDEQ's open burning permit program; and (3) the State participates in Montana State Airshed Group, which implements an enhanced smoke management plan (information on the Montana State Airshed Group can be found at *http://www.smokemu.org/about.cfm*).

[320] State of Montana Air Quality Control Implementation Plan, Volume I, Chapter 9, p. 9.6(8) (Dec. 2, 2011).

area. The FLMs did not identify any integral vistas in Montana. In addition, there have been no certifications of RAVI in the Montana Class I areas, nor are any Montana sources affected by the RAVI provisions. We commit to coordinate the Montana regional haze LTS with our RAVI FIP LTS. We propose to find that the Regional Haze FIP appropriately supplements and augments the EPA FIP for RAVI visibility provisions by updating the monitoring and LTS provisions to address regional haze. We discuss the relevant monitoring provisions further below.

F. Monitoring Strategy and Other Implementation Plan Requirements

40 CFR 51.308(d)(4) requires that the FIP contain a monitoring strategy for measuring, characterizing, and reporting regional haze 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 regional haze for all mandatory Class I Federal areas within the state are being achieved. Consistent with EPA's monitoring regulations for RAVI and regional haze, EPA will rely on the IMPROVE network for compliance purposes, in addition to any RAVI monitoring that may be needed in the future. Further information on monitoring methods and monitor locations can be found in the docket.[321] [322] The most recent report also can be found in the docket.[323] Therefore, we propose to find that we have satisfied the requirements of 40 CFR 51.308(d)(4) enumerated in this paragraph.

40 CFR 51.308(d)(4)(ii) requires that EPA establish procedures by which monitoring data and other information are used in determining the contribution of emissions from within Montana to regional haze 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, participation in the IMPROVE program constitutes compliance with this requirement.

40 CFR 51.308(d)(4)(iv) requires that the FIP 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, EPA should report visibility monitoring data electronically. 40 CFR 51.308(d)(4)(vi) also requires that the FIP provide for other elements, including reporting, recordkeeping, and other measures, necessary to assess and report on visibility. We propose that EPA'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.

40 CFR 51.308(d)(4)(v) requires that EPA 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. EPA must also include a commitment to update the inventory periodically. Please refer to section V.D.1, above, where we discuss EPA's emission inventory for Montana. EPA proposes that we will update statewide emissions inventories periodically and review periodic emissions information from other states and future emissions projections. Additionally, during the next planning period EPA intends to review and consider emissions from oil and gas activities, as well as from other sources. Therefore, we propose that this satisfies the requirement.

G. Coordination With FLMs

The Forest Service manages Anaconda-Pintler WA, Bob Marshall WA, Cabinet Mountains WA, Gates of the Mountains WA, Mission Mountains WA, Scapegoat WA, and Selway-Bitterroot WA. The Fish and Wildlife Service manages the Medicine Lake WA, Red Rocks Lake WA, and U.L. Bend WA. The National Park Service manages Glacier NP and Yellowstone NP. Although the FLMs are very active in participating in the RPOs, the Regional Haze Rule grants the FLMs a special role in the review of regional haze FIPs, summarized in section IV.H, above.

Initially, MDEQ met the requirement of 40 CFR 51.308(i)(1) by sending letters to the FLMs dated November 5, 1999. The letters included the title of the official to which the FLM of any mandatory Class I Federal area could submit any recommendations on the implementation of the regional haze rule including the identification of impairment of visibility in any mandatory Class I Federal area(s) and the identification of elements for inclusion in the visibility monitoring strategy required by 40 CFR 51.305 and the regional haze rule.

Under 40 CFR 51.308(i)(2), we were obligated to provide the Forest Service, the Fish and Wildlife Service, and the National Park Service with an opportunity for consultation, in person and at least 60 days prior to holding a public hearing on the Regional Haze FIP. We sent a draft of our Regional Haze FIP to the Forest Service, the Fish and Wildlife Service, and the National Park Service on February 16, 2012 and March 5, 2012. We notified the FLMs of our public hearings (as initially scheduled) on March 14, 2012. 40 CFR 51.308(i)(3) requires that we provide in our Regional Haze FIP a description of how we addressed any comments provided by the FLMs. We revised our proposed Regional Haze FIP to incorporate comments received by the FLMs.

Lastly, 40 CFR 51.308(i)(4) specifies the regional haze FIP must provide procedures for continuing consultation with the FLMs on the implementation of the visibility protection program required by 40 CFR 51.308, including development and review of implementation plan revisions and 5-year progress reports, and on the implementation of other programs having the potential to contribute to impairment of visibility in mandatory Class I Federal areas. We commit to continue to coordinate and consult with the FLMs as required by 40 CFR 51.308(i)(4). We intend to consult the FLMs in the development and review of implementation plan revisions; review of progress reports; and development and implementation of other programs that may contribute to impairment of visibility at Montana and other Class I areas.

We are proposing that we have complied with the requirements of 40 CFR 51.308(i).

[321] *Visibility Monitoring Guidance,* EPA–454/R–99–003, June 1999, *http://www.epa.gov/ttn/amtic/files/ambient/visible/r-99-003.pdf.*

[322] Guidance for Tracking Progress Under the Regional Haze Rule, EPA–454/B–03–004, September 2003, available at *http://www.epa.gov/ttncaaa1/t1/memoranda/rh_tpurhr_gd.pdf.* Figure 1–2 shows the monitoring network on a map, while Table A–2 lists Class I areas and corresponding monitors.

[323] *Spatial and Seasonal Patterns and Temporal Variability of Haze and its Constituents in the United States,* Report V, ISSN 0737–5352–87, June 2011.

H. Periodic FIP Revisions and Five-Year Progress Reports

Consistent with 40 CFR 51.308(g), we are committing to prepare a progress report in the form of a FIP revision, every five years following the final FIP. The FIP revision will evaluate progress towards the RPG for each mandatory Class I Federal area located within Montana and in each mandatory Class I Federal area located outside Montana that may be affected by emissions from within Montana. The FIP revision will include all the activities in 40 CFR 51.308(g).

VI. Proposed Action

A. Montana Visibility SIP

B. We are proposing to approve the changes to one of the sections of Montana's Visibility SIP that were submitted on February 17, 2012 that includes amendments to the ''Smoke Management'' section, which adds a reference to BACT as the visibility control measure for open burning as currently administered through the State's air quality permit program.

Montana Regional Haze FIP

We are proposing the promulgation of a FIP to address Regional Haze for Montana that we have identified in this proposal. The proposed FIP includes the following elements:

- For Ash Grove Cement:
  - A NO_X BART determination and emission limit of 8 lb/ton clinker that applies on a 30-day rolling average, and a requirement that the owners/operators comply with this NO_X BART limit within five (5) years of the effective date of our final rule.
  - A SO_2 BART determination and emission limit of 11.5 lb/ton clinker that applies on a 30-day rolling average, and a requirement that the owners/operators comply with this SO_2 BART limit within 180 days of the effective date of our final rule.
  - The following PM BART determination and emission limit: if the process weight rate of the kiln is less than or equal to 30 tons per hour, then the emission limit shall be calculated using $E=4.10p^{0.67}$ where E = rate of emission in pounds per hour and p = process weight rate in tons per hour; however, if the process weight rate of the kiln is greater than 30 tons per hour, then the emission limit shall be calculated using $E = 55.0p^{0.11} - 40$, where E = rate of emission in pounds per hour and P = process weight rate in tons per hour. This limit applies on a 30-day rolling average, and a requirement that the owners/operators comply with this PM BART limit within 30 days of the effective date of our final rule.
- For Colstrip Units 1 and 2:
  - NO_X BART determinations and emission limits of 0.15 lb/MMBtu that apply singly to each of these units on a 30-day rolling average, and a requirement that the owners/operators comply with these NO_X BART limits within five (5) years of the effective date of our final rule.
  - SO_2 BART determinations and emission limits of 0.08 lb/MMBtu that apply singly to each of these units on a 30-day rolling average, and a requirement that the owners/operators comply with these SO_2 BART limits within five (5) years of the effective date of our final rule.
  - PM BART determinations and emission limits of 0.10 lb/MMBtu that apply singly to each of these units on a 30-day rolling average, and a requirement that the owners/operators comply with these PM BART limits within 30 days of the effective date of our final rule.
- For Holcim:
  - A NO_X BART determination and emission limit of 5.5 lbs/ton clinker produced that applies on a 30-day rolling average, and a requirement that the owners/operators comply with this NO_X BART limit within five (5) years of the effective date of our final rule.
  - A SO_2 BART determination and emission limit of 1.3 lbs/ton clinker produced that applies on a 30-day rolling average, and a requirement that the owners/operators comply with this SO_2 BART limit within 180 days of the effective date of our final rule.
  - A PM BART determination and emission limit of 0.77 lb/ton clinker produced that applies on a 30-day rolling average, and a requirement that the owners/operators comply with this PM BART limit within 30 days of the effective date of our final rule.
- For Corette:
  - A NO_X BART determination and emission limit of .40 lb/MMBtu that applies on a 30-day rolling average, and a requirement that the owners/operators comply with this NO_X BART limit within 30 days of the effective date of our final rule.
  - A SO_2 BART determination and emission limit of 0.70 lb/MMBtu that applies on a 30-day rolling average, and a requirement that the owners/operators comply with this SO_2 BART limit within 30 days of the effective date of our final rule.
  - A PM BART determination and emission limit of 0.10 lb/MMBtu that applies on a 30-day rolling average, and a requirement that the owners/operators comply with this PM BART limit within 30 days of the effective date of our final rule.
- For Devon Energy Blaine County #1 Compressor Station, a NO_X emission limit of 21.8 lb/hr that applies on a 30-day rolling average, and a requirement, as described in our proposed regulatory text for 40 CFR § 52.1395, that the owners/operators comply with this limit as expeditiously as practicable, but no later than July 31, 2018.
- For CFAC, CFAC must notify EPA 60 days in advance of resuming operation. Once CFAC notifies EPA that it intends to resume operation, EPA will initiate and complete a BART determination after notification and revise the FIP as necessary in accordance with regional haze requirements, including the BART provisions in 40 CFR 51.308(e). CFAC will be required to install any controls that are required as soon as practicable, but in no case later than five years following the effective date of this action.
- For the M2Green Redevelopment LLC, Missoula Site, M2Green Redevelopment LLC must notify EPA 60 days in advance of resuming operation. Once M2 Green Redevelopment LLC notifies EPA that it intends to resume operation, EPA will initiate and complete a four factor analysis after notification and revise the FIP as necessary in accordance with regional haze requirements including the ''reasonable progress'' provisions in 40 CFR 51.308(d)(1). M2 Green Redevelopment LLC will be required to install any controls that are required as soon as practicable, but in no case later than July 31, 2018.
- Monitoring, recordkeeping, and reporting requirements for the above six units to ensure compliance with these emission limitations.
- RPGs consistent with the proposed FIP limits.
- LTS elements that reflect the other aspects of the proposed FIP.

VII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

This proposed action is not a ''significant regulatory action'' under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011). As discussed in detail in section C below, the proposed FIP applies to only six sources. It is therefore not a rule of general applicability.

B. Paperwork Reduction Act

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

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

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

C. Regulatory Flexibility Act

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

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

After considering the economic impacts of this proposed action on small entities, I certify that this proposed action will not have a significant economic impact on a substantial number of small entities. EPA's proposal consists of the proposed partial approval of Montana's Regional Haze SIP submission and the proposed Regional Haze FIP by EPA that adds additional controls to certain sources. The Regional Haze FIP that EPA is proposing for purposes of the regional haze program consists of imposing federal controls to meet the BART requirement for PM, NO_X and SO_2 emissions on specific units at five sources in Montana, and imposing controls to meet the RP requirement for NO_X emissions at one additional source in Montana. The net result of the FIP action is that EPA is proposing direct emission controls on selected units at six sources. The sources in question are two large electric generating plants, two cement plants, and one gas compressor station, and none of these sources are not owned by small entities, and therefore are not small entities. The proposed partial approval of the SIP, if finalized, merely approves state law as meeting federal requirements and imposes no additional requirements beyond those imposed by state law. *See Mid-Tex Electric Cooperative, Inc.* v. *FERC,* 773 F.2d 327 (D.C. Cir. 1985)

D. Unfunded Mandates Reform Act (UMRA)

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

Under Title II of UMRA, EPA has determined that this proposed rule does not contain a federal mandate that may result in expenditures that exceed the inflation-adjusted UMRA threshold of $100 million by State, local, or Tribal governments or the private sector in any one year. In addition, this proposed rule does not contain a significant federal intergovernmental mandate as described by section 203 of UMRA nor does it contain any regulatory requirements that might significantly or uniquely affect small governments.

E. Executive Order 13132: Federalism

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

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

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

Executive Order 13175, entitled *Consultation and Coordination with Indian Tribal Governments* (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.'' This proposed rule does not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments. Thus, Executive Order 13175 does not apply to this rule. However, EPA did send letters, dated October 7, 2011, to each of the Montana Tribes explaining our regional haze FIP action and offering consultation. We did not receive any written or verbal requests from the Montana Tribes for more information or consultation. As a follow-up to our letter, we invited all of the Tribes to a January 5, 2012 conference call. The call was attended by tribal Air Program Managers and one Environmental Director from tribes from four reservations. We will be offering to meet with the Montana Tribes prior to the start of the public hearings being held in Helena and Billings, Montana. EPA specifically solicits additional comment on this proposed rule from tribal officials.

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

Executive Order 13045: *Protection of Children from Environmental Health Risks and Safety Risks* (62 FR 19885, April 23, 1997), applies to any rule that: (1) Is determined to be economically significant as defined under Executive Order 12866; and (2) concerns an environmental health or safety risk that we have reason to believe may have a disproportionate effect on children. EPA interprets EO 13045 as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the EO has the potential to influence the regulation. This action is not subject to EO 13045 because it implements specific standards established by Congress in statutes. However, to the extent this proposed rule will limit emissions of NO_X, SO_2, and PM, the rule will have a beneficial effect on children's health by reducing air pollution.

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

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

I. National Technology Transfer and Advancement Act

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

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

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

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

We have determined that this proposed rule, if finalized, will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. This proposed rule limits emissions of NO_X SO_2 and PM from six sources in Montana.

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 20, 2012.

James B. Martin,

Regional Administrator, Region 8.

40 CFR part 52 is proposed to be amended as follows:

PART 52—[AMENDED]

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

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

Subpart BB—Montana

2. Section 52.1370 is amended by revising paragraph (c)(27)(i)(H) to read as follows:

§ 52.1370 Identification of plan.

* * * * *

(c) * * *

(27) * * *

(i) * * *

(H) Appendix G–2, Montana Smoke Management Plan, effective April 15, 1988, is superseded by § 52.1365.

* * * * *

3. Add § 52.1395 to read as follows:

§ 52.1395 Smoke management plan.

The Department considers smoke management techniques for agriculture and forestry management burning purposes as set forth in 40 CFR 51.308(d)(3)(v)(E). The Department considers the visibility impact of smoke when developing, issuing, or conditioning permits and when making dispersion forecast recommendations through the implementation of Title 17, Chapter 8, subchapter 6, ARM, Open Burning.

4. Add section 52.1396 to read as follows:

§ 52.1396 Federal implementation plan for regional haze.

(a) *Applicability.* This section applies to each owner and operator of the following coal fired electric generating units (EGUs) in the State of Montana: PPL Montana, LLC, Colstrip Power Plant, Units 1, 2; and PPL Montana, LLC, JE Corette Steam Electric Station. This section also applies to each owner and operator of cement kilns at the following cement production plants: Ash Grove Cement, Montana City Plant; and Holcim (US) Inc. Cement, Trident Plant. This section also applies to each owner or operator of Blaine County #1 Compressor Station. This section also applies to each owner and operator of CFAC and M2 Green Redevelopment LLC, Missoula site.

(b) *Definitions.* Terms not defined below shall have the meaning given them in the Clean Air Act or EPA's regulations implementing the Clean Air Act. For purposes of this section:

Boiler operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the EGU. It is not necessary for fuel to be combusted for the entire 24-hour period.

Continuous emission monitoring system or CEMS means the equipment required by this section to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of SO_2 or NO_X emissions, other pollutant emissions, diluent, or stack gas volumetric flow rate.

Kiln operating day means a 24-hour period between 12 midnight and the following midnight during which the kiln operates.

NO_X means nitrogen oxides.

Owner/operator means any person who owns or who operates, controls, or supervises an EGU identified in paragraph (a) of this section.

PM means filterable total particulate matter.

SO_2 means sulfur dioxide.

Unit means any of the EGUs or cement kilns identified in paragraph (a) of this section.

(c) *Emissions limitations.* (1) The owners/operators of EGUs subject to this section shall not emit or cause to be emitted PM, SO_2 or NO_X in excess of the following limitations, in pounds per million British thermal units (lb/MMBtu), averaged over a rolling 30-day period:

Source name	PM Emission limit (lb/MMBtu)	SO_2 Emission limit (lb/MMBtu)	NO_X Emission limit (lb/MMBtu)
Colstrip Unit 1	0.10	0.08	0.15
Colstrip Unit 2	0.10	0.08	0.15
JE Corette Unit 1	0.10	0.70	0.40

(2) The owners/operators of cement kilns subject to this section shall not emit or cause to be emitted PM, SO_2 or NO_X in excess of the following limitations, in pounds per ton of clinker produced, averaged over a rolling 30-day period:

Source name	PM Emission limit (lb/ton clinker)	SO_2 Emission limit (lb/ton clinker)	NO_X Emission limit (lb/ton clinker)
Ash Grove Cement	If the process weight rate of the kiln is less than or equal to 30 tons per hour, then the emission limit shall be calculated using $E = 4.10p^{0.67}$ where E = rate of emission in pounds per hour and p = process weight rate in tons per hour; however, if the process weight rate of the kiln is greater than 30 tons per hour, then the emission limit shall be calculated using $E = 55.0p^{0.11}-40$, where E = rate of emission in pounds per hour and P = process weight rate in tons per hour..	11.5	8.0
Holcim (US) Inc.	0.77 lb/ton	1.3	5.5

(3) The owners/operators of LP, Blaine County #1 Compressor Station shall not emit or cause to be emitted NO_X in excess of 21.8 lbs/hr (30-day rolling average).

(4) These emission limitations shall apply at all times, including startups, shutdowns, emergencies, and malfunctions.

(d) *Compliance date.* The owners and operators of Blaine County #1 Compressor Station shall comply with the emissions limitation and other requirements of this section expeditiously as practicable, but no later than July 31, 2018. The owners and operators of the BART sources subject to this section shall comply with the emissions limitations and other requirements of this section within five years of the effective date of this rule unless otherwise indicated in specific paragraphs.

(e) *Compliance determinations for SO_2 and NO_X.* (1) *CEMS for EGUs.* At all times after the compliance date specified in paragraph (d) of this section, the owner/operator of each unit shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found at 40 CFR part 75, to accurately measure SO_2, NO_X, diluent, and stack gas volumetric flow rate from each unit. The CEMS shall be used to determine compliance with the emission limitations in paragraph (c) of this section for each unit.

(2) *Method for EGUs.* (i) For any hour in which fuel is combusted in a unit, the owner/operator of each unit shall

calculate the hourly average SO_2 and NO_X concentration in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR part 75. At the end of each boiler operating day, the owner/operator shall calculate and record a new 30-day rolling average emission rate in lb/MMBtu from the arithmetic average of all valid hourly emission rates from the CEMS for the current boiler operating day and the previous 29 successive boiler operating days.

(ii) An hourly average SO_2 or NO_X emission rate in lb/MMBtu is valid only if the minimum number of data points, as specified in 40 CFR part 75, is acquired by both the pollutant concentration monitor (SO_2 or NO_X) and the diluent monitor (O_2 or CO_2).

(iii) Data reported to meet the requirements of this section shall not include data substituted using the missing data substitution procedures of subpart D of 40 CFR part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR part 75.

(3) *CEMS for cement kilns.* At all times after the compliance date specified in paragraph (d) of this section, the owner/operator of each unit shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found at 40 CFR 60.63(f), to accurately measure concentration by volume of SO_2 and NO_X emissions into the atmosphere from each unit. The CEMS shall be used to determine compliance with the emission limitations in paragraph (c) of this section for each unit, in combination with data on actual clinker production.

(4) *Method for cement kilns.* (i) The owner/operator of each unit shall record the daily clinker production rates.

(ii) The owner/operator of each unit shall calculate and record the 30-operating day rolling emission rates of SO_2 and NO_X, in lb/ton of clinker produced, as the total of all hourly emissions data for the cement kiln in the preceding 30 days, divided by the total tons of clinker produced in that kiln during the same 30-day operating period, using the following equation:

$$E = (C_sQ_s)/(PK)$$

Where:

E = emission rate of SO_2 or NO_X, lb/ton of clinker produced

C_s = concentration of SO_2 or NO_X, in grains per standard cubic foot (gr/scf);

Q_s = volumetric flow rate of effluent gas, where C_s and Q_s are on the same basis (either wet or dry), scf/hr;

P = total kiln clinker production rate, tons/hr, and

K = conversion factor, 7000 gr/lb.

Hourly clinker production shall be determined in accordance with the requirements found at 40 CFR 60.63(b).

(iii) At the end of each kiln operating day, the owner/operator of each unit shall calculate and record a new 30-day rolling average emission rate in lb/ton clinker from the arithmetic average of all valid hourly emission rates for the current kiln operating day and the previous 29 successive kiln operating days.

(5) The owner/operator of Blaine County #1 Compressor Station shall install a temperature-sensing device (i.e. thermocouple or resistance temperature detectors) before the catalyst in order to monitor the inlet temperatures of the catalyst for each engine. The owner/operator shall maintain the engine at a minimum of at least 750°F and no more than 1250°F in accordance with manufacturer's specifications. Also, the owner/operator shall install gauges before and after the catalyst for each engine in order to monitor pressure drop across the catalyst, and that the owner/operator maintain the pressure drop within ± 2'' water at 100% load plus or minus 10% from the pressure drop across the catalyst measured during the initial performance test. The owner/operator shall follow the manufacturer's recommended maintenance schedule and procedures for each engine and its respective catalyst. The owner/operator shall only fire each engine with natural gas that is of pipeline-quality in all respects except that the CO_2 concentration in the gas shall not be required to be within pipeline-quality.

(f) *Compliance determinations for particulate matter.* (1) *EGU particulate matter BART limits.* Compliance with the particulate matter BART emission limits for each EGU BART unit shall be determined from annual performance stack tests. Within 60 days of the compliance deadline specified in paragraph (d) of this section, and on at least an annual basis thereafter, the owner/operator of each unit shall conduct a stack test on each unit to measure particulate emissions using EPA Method 5, 5B, 5D, or 17, as appropriate, in 40 CFR part 60, Appendix A. A test shall consist of three runs, with each run at least 120 minutes in duration and each run collecting a minimum sample of 60 dry standard cubic feet. Results shall be reported in lb/MMBtu. In addition to annual stack tests, owner/operator shall monitor particulate emissions for compliance with the BART emission limits in accordance with the applicable Compliance Assurance Monitoring (CAM) plan developed and approved in accordance with 40 CFR part 64.

(2) *Cement kiln particulate matter BART limits.* Compliance with the particulate matter BART emission limits for each cement kiln shall be determined from annual performance stack tests. Within 60 days of the compliance deadline specified in paragragh (d) of this section, and on at least an annual basis thereafter, the owner/operator of each unit shall conduct a stack test on each unit to measure particulate matter emissions using EPA Method 5, 5B, 5D, or 17, as appropriate, in 40 CFR part 60, Appendix A. A test shall consist of three runs, with each run at least 120 minutes in duration and each run collecting a minimum sample of 60 dry standard cubic feet. The emission rate (E) of particulate matter, in lb/ton clinker, shall be computed for each run using the equation in paragraph (e)(4)(ii) of this section above. Clinker production shall be determined in accordance with the requirements found at 40 CFR 60.63(b). Results of each test shall be reported as the average of three valid test runs. In addition to annual stack tests, owner/operator shall monitor particulate emissions for compliance with the BART emission limits in accordance with the applicable Compliance Assurance Monitoring (CAM) plan developed and approved in accordance with 40 CFR part 64.

(g) *Recordkeeping for EGUs.* Owner/operator shall maintain the following records for at least five years:

(1) All CEMS data, including the date, place, and time of sampling or measurement; parameters sampled or measured; and results.

(2) Records of quality assurance and quality control activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Part 75 .

(3) Records of all major maintenance activities conducted on emission units, air pollution control equipment, and CEMS.

(4) Any other records required by 40 CFR part 75.

(h) *Recordkeeping for cement kilns.* Owner/operator shall maintain the following records for at least five years:

(1) All CEMS data, including the date, place, and time of sampling or measurement; parameters sampled or measured; and results.

(2) All particulate matter stack test results.

(3) All records of clinker production.

(4) Records of quality assurance and quality control activities for emissions measuring systems including, but not limited to, any records required by

40 CFR part 60, appendix F, Procedure 1.

(5) Records of all major maintenance activities conducted on emission units, air pollution control equipment, CEMS and clinker production measurement devices.

(6) Any other records required by 40 CFR part 75, 40 CFR part 60, Subpart F, or 40 CFR part 60, Appendix F, Procedure 1.

(i) *Reporting.* All reports under this section, with the exception of 40 CFR 53.1395(n) and (o), shall be submitted to the Director, Office of Enforcement, Compliance and Environmental Justice, U.S. Environmental Protection Agency, Region 8, Mail Code 8ENF–AT, 1595 Wynkoop Street, Denver, Colorado 80202–1129.

(1) Owner/operator of each unit shall submit quarterly excess emissions reports for SO_2 and NO_X BART limits no later than the 30th day following the end of each calendar quarter. Excess emissions means emissions that exceed the emissions limits specified in paragraph (c) of this section. The reports shall include the magnitude, date(s), and duration of each period of excess emissions, specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the unit, the nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted.

(2) Owner/operator of each unit shall submit quarterly CEMS performance reports, to include dates and duration of each period during which the CEMS was inoperative (except for zero and span adjustments and calibration checks), reason(s) why the CEMS was inoperative and steps taken to prevent recurrence, and any CEMS repairs or adjustments.

(i) *For EGUs:* Owner/operator of each unit shall also submit results of any CEMS performance tests required by 40 CFR part 75 (Relative Accuracy Test Audits, Relative Accuracy Audits, and Cylinder Gas Audits).

(ii) *For cement kilns:* Owner/operator of each unit shall also submit results of any CEMS performance tests required by 40 CFR part 60, appendix F, Procedure 1 (Relative Accuracy Test Audits, Relative Accuracy Audits, and Cylinder Gas Audits).

(3) When no excess emissions have occurred or the CEMS has not been inoperative, repaired, or adjusted during the reporting period, such information shall be stated in the quarterly reports required by sections (h)(1) and (2) of this section.

(4) Owner/operator of each unit shall submit results of any particulate matter stack tests conducted for demonstrating compliance with the particulate matter BART limits in paragragh (c) of this section.

(j) Monitoring, recordkeeping, and reporting requirements for Blaine County #1 Compressor Station:

(1) The owner/operator shall measure NO_X emissions from each engine at least semi-annually or once every six month period to demonstrate compliance with the emission limits. To meet this requirement, the owner/operator shall measure NO_X emissions from the engines using a portable analyzer and a monitoring protocol approved by EPA.

(2) The owner/operator shall submit the analyzer specifications and monitoring protocol to EPA for approval within 45 calendar days prior to installation of the NSCR unit.

(3) Monitoring for NO_X emissions shall commence during the first complete calendar quarter following the owner/operator's submittal of the initial performance test results for NO_X to EPA.

(4) The owner/operator shall measure the engine exhaust temperature at the inlet to the oxidation catalyst at least once per week and shall measure the pressure drop across the oxidation catalyst monthly.

(5) Each temperature-sensing device shall be accurate to within plus or minus 0.75% of span and that the pressure sensing devices be accurate to within plus or minus 0.1 inches of water.

(6) The owner/operator shall keep records of all temperature and pressure measurements; vendor specifications for the thermocouples and pressure gauges; vendor specifications for the NSCR catalyst and the air-to-fuel ratio controller on each engine.

(7) The owner/operator shall keep records sufficient to demonstrate that the fuel for the engines is pipeline-quality natural gas in all respects, with the exception of the CO_2 concentration in the natural gas.

(8) The owner/operator shall keep records of all required testing and monitoring that include: The date, place, and time of sampling or measurements; the date(s) analyses were performed; the company or entity that performed the analyses; the analytical techniques or methods used; the results of such analyses or measurements; and the operating conditions as existing at the time of sampling or measurement.

(9) The owner/operator shall maintain records of all required monitoring data and support information (*e.g.* all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required) for a period of at least five years from the date of the monitoring sample, measurement, or report and that these records be made available upon request by EPA.

(10) The owner/operator shall submit a written report of the results of the required performance tests to EPA within 90 calendar days of the date of testing completion.

(k) *Notifications.* (1) Owner/operator shall submit notification of commencement of construction of any equipment which is being constructed to comply with the SO_2 or NO_X emission limits in paragraph (c) of this section.

(2) Owner/operator shall submit semi-annual progress reports on construction of any such equipment.

(3) Owner/operator shall submit notification of initial startup of any such equipment.

(l) *Equipment operation.* At all times, owner/operator shall maintain each unit, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

(m) *Credible evidence.* Nothing in this section shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with requirements of this section if the appropriate performance or compliance test procedures or method had been performed.

(n) CFAC notification. CFAC must notify EPA 60 days in advance of resuming operation. CFAC shall submit such notice to the Director, Air Program, U.S. Environmental Protection Agency, Region 8, Mail Code 8P–AR, 1595 Wynkoop Street, Denver, Colorado 80202–1129. Once CFAC notifies EPA that it intends to resume operation, EPA will initiate and complete a BART determination after notification and revise the FIP as necessary in accordance with regional haze requirements, including the BART provisions in 40 CFR 51.308(e). CFAC will be required to install any controls that are required as soon as practicable, but in no case later than five years following the effective date of this rule.

(o) *M2Green Redevelopment LLC notification.* M2Green Redevelopment LLC must notify EPA 60 days in advance of resuming operation. M2Green Redevelopment LLC shall submit such notice to the Director, Air Program, U.S. Environmental Protection Agency, Region 8, Mail Code 8P–AR, 1595 Wynkoop Street, Denver, Colorado 80202–1129. Once M2 Green Redevelopment LLC notifies EPA that it intends to resume operation, EPA will initiate and complete a four factor analysis after notification and revise the FIP as necessary in accordance with regional haze requirements including the ''reasonable progress'' provisions in 40 CFR 51.308(d)(1). M2 Green Redevelopment LLC will be required to install any controls that are required as soon as practicable, but in no case later than July 31, 2018.

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Part III

Environmental Protection Agency

40 CFR Part 52
Approval and Promulgation of Implementation Plans; State of Montana; State Implementation Plan and Regional Haze Federal Implementation Plan; Final Rules

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R08–OAR–2011–0851, FRL 9719–9]

Approval and Promulgation of Implementation Plans; State of Montana; State Implementation Plan and Regional Haze Federal Implementation Plan

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is promulgating a Federal Implementation Plan (FIP) to address regional haze in the State of Montana. EPA developed this FIP in response to the State's decision in 2006 to not submit a regional haze State Implementation Plan (SIP) revision. The FIP satisfies requirements of the Clean Air Act (CAA or ''the Act'') that require states, or EPA in promulgating a FIP, to assure reasonable progress towards the national goal of preventing any future and remedying any existing man-made impairment of visibility in mandatory Class I areas. In addition, EPA is approving one of the revisions to the Montana SIP submitted by the State of Montana through the Montana Department of Environmental Quality on February 17, 2012, specifically, the revision to the Montana Visibility Plan that includes amendments to the ''Smoke Management'' section, which adds a reference to Best Available Control Technology (BACT) as the visibility control measure for open burning as currently administered through the State's air quality permit program. This change was made to meet the requirements of the Regional Haze Rule. EPA will act on the remaining February 17, 2012 revisions in the State's submittal in a future action.

DATES: This final rule is effective October 18, 2012.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–R08–OAR–2011–0851. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, e.g., Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *www.regulations.gov,* or in hard copy at the Air Program, Environmental Protection Agency (EPA), Region 8, 1595 Wynkoop Street, 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 a.m. to 4 p.m., excluding Federal holidays.

FOR FURTHER INFORMATION CONTACT: Scott Jackson, Air Program, Mailcode 8P–AR, Environmental Protection Agency, Region 8, 1595 Wynkoop Street, Denver, Colorado 80202–1129, (303) 312–6107, or *Jackson.Scott@epa.gov.*

SUPPLEMENTARY INFORMATION:

Definitions

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

- The words or initials *Act* or *CAA* mean or refer to the Clean Air Act, unless the context indicates otherwise.
- The initials *A/F* mean or refer to air-to-fuel.
- The initials *ALM* mean or refer to Ammonia Limiting Method
- The initials *ARM* mean or refer to Administrative Rule of Montana.
- The initials *ARP* mean or refer to the acid rain program.
- The initials *ARS* mean or refer to Air Resources Specialists.
- The initials *ASOFA* mean or refer to advanced separated overfire air.
- The initials *BACT* mean or refer to Best Available Control Technology.
- The initials *BART* mean or refer to Best Available Retrofit Technology.
- The initials *CAA* mean or refer to the Clean Air Act.
- The initials *CAM* mean or refer to compliance assurance monitoring.
- The initials *CAMD* mean or refer to EPA Clean Air Markets Division.
- The initials *CAMx* mean or refer to Comprehensive Air Quality Model.
- The initials *CBI* mean or refer to confidential business information.
- The initials *CCM* mean or refer to EPA Control Cost Manual.
- The initials *CCOFA* mean or refer to close-coupled overfire air system.
- The initials *CDS* mean or refer to circulating dry scrubber.
- The initials *CGA* mean or refer to gas cylinder audit.
- The initials *CELP* mean or refer to Colstrip Energy Limited Partnership.
- The initials *CEMS* mean or refer to continuous emissions monitoring systems.
- The initials *CEPCI* mean or refer to Chemical Engineering Plant Cost Index.
- The initials *CFAC* mean or refer to Columbia Falls Aluminum Company.
- The initials *CFB* mean or refer to circulating fluidized bed.
- The initials *CKD* mean or refer to cement kiln dust.
- The initials *CMAQ* mean or refer to Community Multi-Scale Air Quality modeling system.
- The initials *CPMS* mean or refer to continuous parametric monitoring system.
- The initials *CO* mean or refer to carbon monoxide.
- The initials *CPI* mean or refer to Consumer Price Index.
- The initials *CRF* mean or refer to Capital Recovery Factor.
- The initials *CSAPR* mean or refer to Cross-State Air Pollution Rule.
- The initials *DAA* mean or refer to Dry Absorbent Addition.
- The initials *DPCS* mean or refer to digital process control system.
- The initials *D-R* mean or refer to Dresser-Rand.
- The initials *DSI* mean or refer to dry sorbent injection.
- The initials *EC* mean or refer to elemental carbon.
- The initials *EGU* mean or refer to Electric Generating Units.
- The words *EPA, we, us* or *our* mean or refer to the United States Environmental Protection Agency.
- The initials *ESP* mean or refer to electrostatic precipitator.
- The initials *FCCU* mean or refer to fluid catalytic cracking unit.
- The initials *FGD* mean or refer to flue gas desulfurization.
- The initials *FGR* mean or refer to flue gas recirculation.
- The initials *FIP* mean or refer to Federal Implementation Plan.
- The initials *FLMs* mean or refer to Federal Land Managers.
- The initials *HAR* mean or refer to hydrated ash reinjection.
- The initials *HDSCR* mean or refer to high-dust selective catalytic reduction.
- The initials *HC* mean or refer to hydrocarbons.
- The initials *gr/scf* mean or refer to grains per standard cubic foot.
- The initials *IMPROVE* mean or refer to Interagency Monitoring of Protected Visual Environments monitoring network.
- The initials *IPM* mean or refer to Integrated Planning Model.
- The initials *IWAQM* refer to Interagency Workgroup on Air Quality Modeling.
- The initials *LDSCR* mean or refer to low-dust selective catalytic reduction.
- The initials *LEA* mean or refer to low excess air.
- The initials *LNBs* mean or refer to low NO_X burners.

• The initials *LSD* mean or refer to lime spray drying.
• The initials *LSFO* mean or refer to limestone forced oxidation.
• The initials *LTS* mean or refer to Long-Term Strategy.
• The initials *MACT* mean or refer to maximum achievable control technology.
• The initials *MATB* mean or refer to Montanan's Against Toxic Burning.
• The initials *MDEQ* mean or refer to Montana's Department of Environmental Quality.
• The initials *MDF* mean or refer to medium density fiberboard.
• The initials *MISO* mean or refer to Midwest Independent Transmission System Operator.
• The initials *MDU* mean or refer to Montana-Dakota Utilities Company.
• The initials *MEL* mean magnesium-enhanced lime.
• The initials *MKF* mean or refer to mid-kiln firing of solid fuel.
• The words *Montana* and *State* mean the State of Montana.
• The initials *MSCC* mean or refer to Montana Sulphur and Chemical Company.
• The initials *NAAQS* mean or refer to National Ambient Air Quality Standards.
• The initials *NC* mean or refer to North Carolina.
• The initials *ND* mean or refer to North Dakota.
• The initials *NEI* mean or refer to National Emission Inventory.
• The initials *NESHAP* mean or refer to National Emission Standards for Hazardous Air Pollutants.
• The initials NH_3 mean or refer to ammonia.
• The initials NO_X mean or refer to nitrogen oxides.
• The initials *NP* mean or refer to National Park.
• The initials *NPS* mean or refer to National Parks Service.
• The initials *NSCR* mean or refer to non-selective catalytic reduction.
• The initials *NSPS* mean or refer to New Source Performance Standards.
• The initials *NWR* mean or refer to National Wildlife Reserve.
• The initials *OMB* mean or refer to the Office of Management and Budget.
• The initials *OC* mean or refer to organic carbon.
• The initials *OFA* mean or refer to overfire air.
• The initials *PC* mean or refer to pulverized coal.
• The initials *PH/PC* mean or refer to preheater/precalciner.
• The initials *PM* mean or refer to particulate matter.
• The initials $PM_{2.5}$ mean or refer to particulate matter with an aerodynamic diameter of less than 2.5 micrometers (fine particulate matter).
• The initials PM_{10} mean or refer to particulate matter with an aerodynamic diameter of less than 10 micrometers (coarse particulate matter).
• The initials *PMCD* mean or refer to particulate matter control device.
• The initials *ppb* mean or refer to parts per billion.
• The initials *ppm* mean or refer to parts per million.
• The initials *PRB* mean or refer to Powder River Basin.
• The initials *PSAT* mean or refer to Particulate Matter Source Apportionment Technology.
• The initials *PSD* mean or refer to Prevention of Significant Deterioration.
• The fraction *Q/D* means quantity of emissions over distance.
• The initials *RAA* mean or refer to relative accuracy audit.
• The initials *RATA* mean or refer to relative accuracy test audit.
• The initials *RAVI* mean or refer to Reasonably Attributable Visibility Impairment.
• The initials *RICE* mean or refer to Reciprocating Internal Combustion Engines.
• The initials *RMC* mean or refer to Regional Modeling Center.
• The initials *ROFA* mean or refer to rotating opposed fire air.
• The initials *RP* mean or refer to Reasonable Progress.
• The initials *RPG* or *RPGs* mean or refer to Reasonable Progress Goal(s).
• The initials *RPOs* mean or refer to regional planning organizations.
• The initials *RRI* mean or refer to rich reagent injection.
• The initials *RSCR* mean or refer to regenerative selective catalytic reduction.
• The initials *SCOT* mean or refer to Shell Claus Off-Gas Treatment.
• The initials *SCR* mean or refer to selective catalytic reduction.
• The initials *SDA* mean or refer to spray dryer absorbers.
• The initials *SIP* mean or refer to State Implementation Plan.
• The initials *SMOKE* mean or refer to Sparse Matrix Operator Kernel Emissions.
• The initials *SNCR* mean or refer to selective non-catalytic reduction.
• The initials SO_2 mean or refer to sulfur dioxide.
• The initials *SOFA* mean or refer to separated overfire air.
• The initials *SRU* mean or refer to sulfur recovery unit.
• The initials *TAC* mean or refer to Texas Administrative Code.
• The initials *TESCR* mean or refer to tail-end selective catalytic reduction.
• The initials *TCEQ* mean or refer to Texas Commission on Environmental Quality.
• The initials *tpy* mean tons per year.
• The initials *TSD* mean or refer to Technical Support Document.
• The initials *URP* mean or refer to Uniform Rate of Progress.
• The initials *USFWS* mean or refer to U.S. Fish and Wildlife Service.
• The initials *VOC* mean or refer to volatile organic compounds.
• The initials *WA* mean or refer to Wilderness Area.
• The initials *WEG* mean or refer to WildEarth Guardians.
• The initials *WEP* mean or refer to Weighted Emissions Potential.
• The initials *WETA* mean or refer to Western Environmental Trade Association.
• The initials *WRAP* mean or refer to the Western Regional Air Partnership.
• The initials *YELP* mean or refer to Yellowstone Energy Limited Partnership.

Table of Contents

I. Background

We signed our notice of proposed rulemaking on March 20, 2012, and it was published in the **Federal Register** on April 20, 2012. In that notice, we proposed a FIP to address regional haze in the State of Montana for the first implementation period (through 2018) including determinations of Best Available Retrofit Technology (BART) for specific sources subject to that requirement. 77 FR 23988. Montana did not submit a SIP, knowing that as a consequence EPA would be required to propose and finalize a FIP. A detailed explanation of the CAA's visibility requirements and the Regional Haze Rule as it applies to Montana was provided in the notice of proposed rulemaking and will not be restated here. In that notice, we also proposed to approve a revision to the Montana SIP submitted by the State of Montana through the Montana Department of Environmental Quality on February 17, 2012. The State's submittal contained revisions to the Montana Visibility Plan that included amendments to the ''Smoke Management'' section, which adds a reference to Best Available Control Technology (BACT) as the visibility control measure for open burning as currently administered through the State's air quality permit program. EPA's rationale for proposing approval of the revisions to the Montana Visibility Plan that included amendments to the ''Smoke Management'' section was described in detail in the proposal and will not be restated here. We note that in the future, Montana retains the option of submitting a SIP meeting the requirements of the Regional Haze Rule, to replace the FIP.

II. Basis for Our Final Action

We have fully considered all significant comments on our proposal, and, except as noted in section V, below, have concluded that no other changes from our proposal are warranted. Our action is based on an evaluation of Montana's Visibility SIP submittal and our FIP against the regional haze requirements at 40 CFR 51.300—51.309 and CAA sections 169A and 169B. All general SIP requirements contained in CAA section 110, other provisions of the CAA, and our regulations applicable to this action were also evaluated. The purpose of this action is to ensure compliance with these requirements. Our authority for action on Montana's Visibility SIP submittal is based on CAA section 110(k). Our authority to promulgate our FIP is based on CAA section 110(c).

III. Final Action

With this final action we are approving Montana's submittal containing revisions to the ''Smoke Management'' section of Montana's Visibility Plan that was submitted by the State through the Montana DEQ on February 17, 2012. The SIP includes amendments to the ''Smoke Management'' section, which adds a reference to BACT as the visibility control measure for open burning as currently administered through the State's air quality permit program as meeting the requirement of 40 CFR 308(d)(3)(v) to consider smoke management techniques for agricultural and forestry management purposes including plans as they currently exist within the state for these purposes. We are promulgating a FIP for the remaining parts of the regional haze requirements. Table 1 shows the control technologies, associated cost, and emission reductions for each source that is subject to the FIP.

TABLE 1—CONTROL TECHNOLOGIES, COST, EMISSIONS REDUCTIONS AND COST-EFFECTIVENESS

Source	Technology [1]	Total capital cost ($)	Total annualized cost ($)	Annual NO_X/SO_2 emissions reductions (tpy)	Cost effectiveness ($/ton)
Ash Grove Cement	LNB + SNCR	1,191,632	2,238,893	1,088 NO_X	2,058
Holcim, Inc	SNCR	1,312,800	650,399	556 NO_X	1,170
Colstrip Unit 1	SOFA + SNCR	13,380,673	3,278,964	2,097 NO_X	1,564
Colstrip Unit 2	Lime Injection + Additional Scrubber Vessel.	28,000,000	4,093,200	4,486 SO_2	912
Colstrip Unit 2	SOFA + SNCR	13,380,673	3,256,127	2,072 NO_X	1,571
Colstrip Unit 2	Lime Injection + Additional Scrubber Vessel.	28,000,000	4,093,200	4,129 SO_2	991
Devon Energy, Blaine County #1 Compressor Station, Engine #1.	NSCR	—	105,000	335 NO_X	282
Devon Energy, Blaine County #1 Compressor Station, Engine #2.	NSCR	—	105,000	335 NO_X	282
Cumulative Total Annual Cost.			13,727,583		

— Total Capital Cost was not calculated.
[1] The technology listed is the technology evaluated as BART, but sources can choose to use another technology or combination of technologies to meet established emission limits. Also where additional control technologies are not required, existing controls may still be necessary to meet established emission limits.

IV. Issues Raised by Commenters and EPA's Responses

This action addresses comments on the Montana Regional Haze FIP. The publication of EPA's proposed rule on April 20, 2012 resulted in a 60-day public comment period that ended on June 19, 2012. We held four public hearings for this proposal. Two hearings were held in Helena, Montana on Tuesday, May 1, 2012 and two hearings were held in Billings, Montana on

Wednesday, May 2, 2012. During the public comment period we received numerous written comments from individual citizens, members of various organizations, and also from Ash Grove Cement (Ash Grove), Columbia Falls Aluminum Corporation (CFAC), EarthJustice, the U.S. Fish and Wildlife Service (USFWS), Holcim Inc. (Holcim), Montana Dakota Utilities (MDU), Montana Sulphur and Chemical Company, the National Parks Service (NPS), the owners of Colstrip Units 1–4, the State of Montana, and WildEarth Guardians (WEG). We have reviewed the comments and provided our responses below. Transcripts from the public hearings and full copies of the comment letters are available in the docket for review.

A. Comments on Modeling

Comment: PPL and others stated that the proposed BART at Colstrip 1 and 2 for both NO_X and SO_2 would result in no reasonably anticipated visibility benefit, even assuming that EPA's emissions reduction estimates and modeling are correct. In one specific comment, the commenter stated:

> A projected 0.066 dv is not a visibility improvement that 'may reasonably be anticipated to result from the use' of additional scrubber vessels at Colstrip Units 1 and 2. 42 U.S.C. 7491(g)(2). Such an insignificant projected visibility change is beyond the modeling capability of the CALPUFF model version EPA used and is far below the threshold for human perceptibility.

Response: We disagree that any controls required by our action must demonstrate a perceptible visibility improvement. In a situation where the installation of BART may not result in a perceptible improvement in visibility, the visibility benefit may still be significant. The Regional Haze Rule states:

> even though the visibility improvement from an individual source may not be perceptible, it should still be considered in setting BART because the contribution to haze may be significant relative to other source contributions in the Class I area. Failing to consider less-than-perceptible contributions to visibility impairment would ignore the CAA's intent to have BART requirements apply to sources that contribute to, as well as cause, such impairment.

70 FR 39129.

Visibility impacts below the thresholds of perceptibility cannot be ignored because regional haze is produced by a multitude of sources and activities which are located across a broad geographic area. As stated in our proposal, with respect to Colstrip 1 and 2, we weighed the relatively low costs for lime injection with the additional scrubber vessel against the anticipated visibility impacts and determined that the cost was justified by the visibility improvement. Similarly, we weighed the relatively low cost of separated overfire air (SOFA) + selective noncatalytic reduction (SNCR) against the anticipated visibility benefit and determined that the cost was justified by the visibility benefit.

We respond to the modeling capabilities of CALPUFF in a response to a later comment.

Comment: A commenter asserted that EPA's modeling assumes constant levels of ammonia and failed to consider monitoring data showing that ammonia levels are lower during the winter months.

Response: EPA recognizes that there can be seasonal variability in ambient ammonia concentrations and that it is preferable to use ambient ammonia measurements when such data are available rather than using default background ammonia concentrations. Ammonia monitoring data is not available in Montana, however, ammonia monitoring data is available in western North Dakota at the Beulah monitoring site. Theodore Roosevelt NP, located in western North Dakota, is impacted by Montana BART sources and EPA determined that it would be more appropriate to use the North Dakota ammonia monitoring data instead of using CALPUFF default ammonia concentrations. Therefore EPA used monthly average measured ammonia concentrations shown in Table 2 that were measured by North Dakota at their Beulah monitoring site.[1] The monthly average ammonia concentrations values were derived from data collected during years 2001–2002 and the ambient data were filtered to eliminate data from wind directions associated with sources causing a local bias. North Dakota concluded in its regional haze modeling analysis that these monthly average ammonia values are generally representative of background ammonia concentrations in western North Dakota. As a result, we did not assume a constant level of ammonia as asserted by the commenter, and we did represent seasonal variability in ammonia concentrations.

Additionally, EPA used the POSTUTIL[2] program with the Ammonia Limiting Method (ALM) to post-process the CALPUFF output to correct the assumption of constant ammonia availability in the model. The CALPUFF model represents multiple plumes that can overlap. The default model approach assumes that background ammonia is fully available to form nitrate in each plume. The ALM method corrects this assumption by partitioning the ammonia between overlapping plumes. Therefore, EPA has fully accounted for non-constant ammonia levels by using monthly measured background ammonia and by using the ALM in the analysis of CALPUFF model results.

TABLE 2—MONTHLY AMMONIA BACKGROUND CONCENTRATIONS

Month	Value (ppb)
Jan	1.22
Feb	1.23
Mar	1.60
Apr	1.94
May	2.29
Jun	1.63
Jul	1.65
Aug	1.69
Sep	0.98
Oct	1.04
Nov	1.37
Dec	1.06

Comment: A commenter stated that EPA failed to acknowledge uncertainty in the CALPUFF model at short distances, and the commenter further argues that model uncertainty increases at distances greater than 200 km and has a tendency to over predict impacts at greater distances.

Response: The Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 report (EPA, 1998)[3] reviewed model performance evaluations of CALPUFF as a function of distance from the source and concluded that:

> Based on the tracer comparison results presented in Section 4.6, it appears that CALPUFF provides reasonable correspondence with observations for transport distances of over 100 km. Most of these comparisons involved concentration values averaged over 5 to 12 hours. The CAPTEX comparisons, which involved comparisons at receptors that were 300 km to 1000 km from the release, suggest that CALPUFF can overestimate surface concentrations by a factor of 3 to 4. Use of

[1] Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota (Final), North Dakota Department of Health, Division of Air Quality, 1200 Missouri Avenue Bismarck, ND (Nov 2005), p 32–33.

[2] POSTUTIL is a part of the suite of programs associated with the CALPUFF modeling system and is used to repartition ammonia in overlapping puffs. The model is available at: *http://www.src.com/calpuff/calpuff1.htm.*

[3] Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Report and Recommendations for Long-Range Transport Impacts. EPA–454/R–98–019. U.S. Environmental Protection Agency. Research Triangle Park, NC (''IWAQM Phase II Report'') (1998), p 18.

the puff splitting option in CALPUFF might have improved these comparisons, but there are serious conceptual concerns with the use of puff dispersion for very long-range transport (300 km and beyond). As the puffs enlarge due to dispersion, it becomes problematic to characterize the transport by a single wind vector, as significant wind direction shear may well exist over the puff dimensions. With the above thoughts in mind, IWAQM recommends use of CALPUFF for transport distances of order 200 km and less. Use of CALPUFF for characterizing transport beyond 200 to 300 km should be done cautiously with an awareness of the likely problems involved.

Therefore, we modeled Class I areas within 300 km of each BART sources but did not model impacts at distances exceeding 300 km.

EPA has acknowledged that there is uncertainty in the CALPUFF model predicted visibility impacts. However, the CALPUFF model can both underpredict and overpredict visibility impacts. For example, in a presentation for the 2010 annual Community Modeling and Analysis System conference, Anderson et al. (2010) [4] found that the CALPUFF model frequently predicted lower nitrate concentrations compared to the CAMx photochemical grid model which has a much more rigorous treatment of photochemical reactions. EPA recognized the uncertainty in the CALPUFF modeling results when EPA made the decision, in the final BART Guidelines, to recommend that the model be used to estimate the 98th percentile visibility impairment rather than the highest daily impact value. While recognizing the limitations of the CALPUFF model in the BART Guidelines Preamble, EPA concluded that, for the specific purposes of the Regional Haze Rule's BART provisions, CALPUFF is sufficiently reliable to inform the decision making process. The Preamble states:

Because of the scale of the predicted impacts from these sources, CALPUFF is an appropriate or a reasonable application to determine whether such a facility can reasonably be anticipated to cause or contribute to any impairment of visibility. In other words, to find that a source with a predicted maximum impact greater than 2 or 3 deciviews meets the contribution threshold adopted by the States does not require the degree of certainty in the results of the model that might be required for other regulatory purposes. In the unlikely case that a State were to find that a 750 MW power plant's predicted contribution to visibility impairment is within a very narrow range between exemption from or being subject to BART, the State can work with EPA and the FLM to evaluate the CALPUFF results in combination with information derived from other appropriate techniques for estimating visibility impacts to inform the BART applicability determination. Similarly for other types of BART eligible sources, States can work with the EPA and FLM to determine appropriate methods for assessing a single source's impacts on visibility.

77 FR 39123.

Therefore, given that the IWAQM guidance provides for the use of the CALPUFF model at receptor distances of up to 200 to 300 km, and given that EPA has already addressed uncertainty in the CALPUFF model, we believe it is reasonable to use CALPUFF to evaluate visibility impacts up to 300 km.

Comment: A commenter stated that the CALPUFF model cannot accurately predict visibility changes at the levels EPA predicted for Holcim using indirect firing alone (0.125 deciview) or even for the additional improvement from the combination of SNCR + indirect firing as compared to SNCR alone. The commenter believes that the EPA predicted visibility improvement of 0.424 deciview for the combination of SNCR + indirect firing is within the uncertainty range of the CALPUFF model and cannot reliably predict visibility improvements.

Response: We disagree. EPA has previously addressed the issue of uncertainty in the CALPUFF model. EPA recognized the uncertainty in the CALPUFF modeling results when EPA made the decision in the final BART Guideline to recommend that the model be used to estimate the 98th percentile visibility impairment rather than the highest daily impact value. While recognizing the limitations of the CALPUFF model in the Preamble, EPA concluded that, for the specific purposes of the Regional Haze Rule's BART provisions, CALPUFF is sufficiently reliable to inform the decision making process. 70 FR 39123. We continue to maintain that it is appropriate to use CALPUFF for BART modeling for Holcim and other Montana BART sources.

Comment: Some commenters stated that we should have modeled impacts to additional Class I areas. Some commenters stated that EPA should have modeled visibility impacts on Class I areas at a distance of up to 500 km from the BART source and some commenters specified certain Class I areas that they thought should be included in the modeling for a particular source.

Some commenters stated that the Western Regional Air Partnership (WRAP) subject to BART modeling indicated impacts from BART sources to additional Class I areas that we did not assess. One commenter stated that when assessing the impacts from the Big Stone I facility in the South Dakota SIP, EPA evaluated visibility as far away as Badlands National Park (NP), 470 km, Theodore Roosevelt NP, 555 km, and Boundary Waters Wilderness Area (WA) and Voyageurs NP, 431 and 438 km, respectively, and the commenter stated that, EPA should evaluate visibility impacts at more distant Class I areas for the Montana FIP.

Response: We modeled all Class I areas within 300 km of the BART source. As discussed in a response to a previous comment, the IWAQM Phase 2 report concluded that CALPUFF can overestimate surface concentrations at distances of 300 to 1,000 km by a factor of 3 to 4. Therefore, IWAQM recommends use of CALPUFF for transport distances of approximately 200 km or less. Use of CALPUFF for characterizing transport beyond 200 to 300 km should be done cautiously with an awareness of the likely problems involved. Therefore, we modeled Class I areas within 300 km of each BART source. We did not model impacts at distances exceeding 300 km.

In the case of the Big Stone I facility in South Dakota, there were no Class I areas within a distance of 300 km of the source. Therefore, the State and the facility agreed in their modeling protocol to evaluate visibility impacts at more distant sources by using a non-regulatory option in CALPUFF called ''puff splitting''. As discussed in the IWAQM Guidance,[5] the use of the puff splitting option in CALPUFF might improve model performance at long distances, but there are also serious conceptual concerns with the use puff splitting to represent puff dispersion for very long-range transport at distances of more than 300 km. EPA concurred with South Dakota on this approach for Big Stone I because there were no Class I areas within 300 km of the source, and EPA approved the South Dakota SIP using these modeling results. In the case of Montana, there are several Class I areas less than 300 km from each BART source, and EPA based its analysis on CALPUFF visibility model results for these areas.

EPA did not use the non-regulatory puff splitting option in CALPUFF to model more distant sources because of

[4] Anderson, B., K. Baker, R. Morris, C. Emery, A. Hawkins, E. Snyder ''Proof-of-Concept Evaluation of Use of Photochemical Grid Model Source Apportionment Techniques for Prevention of Significant Deterioration of Air Quality Analysis Requirements'' Presentation for Community Modeling and Analysis System (CMAS) 2010 Annual Conference, (October 11–15, 2010) can be found at *http://www.cmascenter.org/conference/2010/agenda.cfm.*

[5] IWAQM Phase 2 report, p. 27.

the greater uncertainty in model results at distances of more than 300 km, as we have explained in previous responses.

While WRAP performed CALPUFF modeling at Class I areas more distant than 300 km from Colstrip, WRAP also recognized the larger uncertainty in the model results for distances greater than 300 km. and included the following caveat in their modeling protocol:

> Relevant guidance suggests that the CALPUFF model is generally applicable at distances from 50 km to 300 km downwind and may be used for distance less than 50 km when complex flows exist on a case by case basis. [citation omitted] Class I areas in the west generally are located in complex terrain resulting in complex flows. Consequently, the BART screening modeling conducted by the RMC will include results for potential BART eligible sources that reside within 50 km of a Class I area. The WRAP RMC BART screening modeling may also apply CALPUFF to downwind distances greater than 300 km. When providing results to the States, the downwind distance between the BART source and the Class I area will be included, and a recommendation from the RMC as to the utility of applying the results for Class I areas less than 50 km and greater than 300 km from the source. The individual States will need to make their own regulatory assessment of the applicability of the model results at those distances less than 50 km and greater than 300 km.[6]

It also should be noted that WRAP found smaller visibility impacts at the distances of more than 300 km compared to Class I areas at distances of less than 300 km.[7] The BART Guidelines explain that if the highest modeled effects are observed at the nearest Class I area, it may not be necessary to model other Class I areas. The BART Guidelines state:

> One important element of the protocol is in establishing the receptors that will be used in the model. The receptors that you use should be located in the nearest Class I area with sufficient density to identify the likely visibility effects of the source. For other Class I areas in relatively close proximity to a BART-eligible source, you may model a few strategic receptors to determine whether effects at those areas may be greater than at the nearest Class I area. For example, you might choose to locate receptors at these areas at the closest point to the source, at the highest and lowest elevation in the Class I area, at the IMPROVE monitor, and at the approximate expected plume release height. If the highest modeled effects are observed at the nearest Class I area, you may choose not to analyze the other Class I areas any further as additional analyses might be unwarranted.

70 FR 39170.

Comment: Commenters stated that EPA should have added the visibility impacts at each Class I area to assess cumulative visibility impacts.

Response: Contrary to the commenter's assertion, we did assess cumulative visibility impacts. In our analysis of visibility impacts, we considered the visibility improvement at all Class I areas within 300 km of the subject BART unit. For example, in our analysis of BART control options for Corette, we considered the visibility improvement at all Class I areas within 300 km (Gates of the Mountains WA, North Absaroka WA, Red Rock Lakes WA, Teton WA, UL Bend WA, Washakie WA, and Yellowstone NP). 77 FR 24042 and 77 FR 24046. In our proposal, for each of the BART sources we assessed the visibility improvement at each Class I area within 300 km of the source associated with the controls under consideration, as well as the number of days with a greater than 0.5 deciview impact at each of these Class I areas. Therefore, our proposed rule did not ignore the visibility improvement that would be achieved at areas other than the most impacted Class I area, and we disagree with the assertions that we did not consider the impacts at multiple Class I areas. We did, however, in the proposed rule focus on the visibility benefits at those Class I areas with the most meaningful visibility impacts in determining whether NO_X or SO_2 controls should be determined to be BART. We took a similar approach for all the Montana BART units. We did not ignore the visibility benefits at the other Class I areas but did not consider the benefits sufficient to warrant a change in our determination as to the appropriate level of control.

Comment: USFWS stated that for the three SO_2 control alternatives, EPA made judgments on cost per deciview based on only the most impacted Class I area, Washakie WA and that USFWS continued to believe that it is appropriate to consider both the degree of visibility improvement in a given Class I area as well as the cumulative effects of improving visibility across all of the Class I areas affected. USFWS stated that it does not make sense to use the same metric to evaluate the effects of reducing emissions from a BART source that impacts only one Class I area as for a BART source that impacts multiple Class I areas and that it does not make sense to evaluate impacts at one Class I area, while ignoring others that are similarly significantly impaired. USFWS stated that if emissions from Corette are reduced, the benefits will be spread well beyond only the most impacted Class I area, and this must be accounted for. USFWS stated that, in the context of the multiple Class I areas that are affected by Corette, the Lime Spray Dryer (LSD) SO_2 control alternative, the cumulative Class I area impact is $12.7 million per deciview of visibility improvement and costs $4,981 per ton of SO_2 removed USFWS stated that LSD should be considered as being a viable candidate for BART for Corette. USFWS made similar comments regarding NO_X controls for Corette.

Response: We disagree. In our analysis of visibility impacts, we considered the visibility improvement at all Class I areas within 300 km of the subject BART unit. As explained in the response to the previous comment, in our analysis of BART control options for Corette, we considered the visibility improvement at all Class I areas within 300 km. In our proposal, for each of the BART sources we assessed the visibility improvement at each Class I area within 300 km of the source associated with the controls under consideration, as well as the number of days with a greater than 0.5 deciview impact at each of these Class I areas. Therefore, our proposed rule did not ignore the visibility improvement that would be achieved at areas other than the most impacted Class I area, and we disagree with the assertions that we did not consider the impacts at multiple Class I areas. We did, however, in the proposed rule focus on the visibility benefits at those Class I areas with the most meaningful visibility impacts in determining whether NO_X or SO_2 controls should be determined to be BART. We did not ignore the visibility benefits at the other Class I areas but did not consider the benefits sufficient to warrant a change in our determination as to the appropriate level of control. As we explained in other responses, we did not use the $/deciview ratio as a basis for our decision.

Comment: EarthJustice's consultant Air Resources Specialists (ARS) performed additional analysis on possible visibility benefits of SCR at Colstrip Units 1 and 2 combined with the benefits of BART controls on SO_2 emissions. The commenter stated that the ARS analysis ''demonstrates that EPA's analysis of visibility benefits of selective catalytic reduction (SCR) controls is incomplete and inadequate.'' The commenter also stated, ''the evidence demonstrates that with SCR and SO_2 controls, the visibility impairment at UL Bend WA and Theodore Roosevelt NP attributable to

[6] CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I areas in the Western United States Available at *http://pah.cert.ucr.edu/aqm/308/bart/WRAP_RMC_BART_Protocol_Aug15_2006.pdf.*

[7] Summary of WRAP RMC BART Modeling for Montana, Draft #5 May 30, 2007. More information can be found at *http://pah.cert.ucr.edu/aqm/308/bart.shtml.*

Colstrip would be virtually eliminated, the very goal of the CAA haze requirements.''

The commenter also stated that when SCR + SOFA is coupled with a dry scrubber/baghouse, it is likely that Corette would no longer have any noticeable impact on haze in any Class I area, and this result complies with the Congressional directive to eliminate haze in Class I areas.

Response: We disagree that our analysis was incomplete or inadequate. We analyzed visibility benefits for both SO_2 and NO_X emissions reductions following procedures established in the BART Guidelines, and we proposed emissions reductions consistent with the five factor analysis. The Regional Haze Rule has a goal that anthropogenic visibility impairment be eliminated by 2064; however, it does not require that all anthropogenic contributions to visibility impacts be fully eliminated in the near term, nor is that the goal of the BART element of the Regional Haze program. 40 CFR 51.308 (e)(1)(ii)(A) requires that EPA consider the cost of compliance; the energy and nonair quality environmental impacts; any pollution control equipment in use at the source; the remaining useful life of the source; and the degree of improvement which may be reasonably anticipated to result from the use of such technology. Visibility improvement is only one of the five factors that are required to be considered. Our proposed BART controls achieve significant reductions in contributions to visibility impairment while also considering other components of the five factor analysis.

Comment: EarthJustice stated that, ''ARS concluded that the incremental benefit of SCR compared to SNCR at Colstrip Units 1 and 2 is larger when viewed in combination with the SO_2 emission controls at either emission rate.''

Response: ARS estimated the relative improvement in SCR compared to SNCR for the case with baseline SO_2 emissions and for the case with our proposed BART SO_2 emissions. The ARS analysis showed that the incremental improvement in SCR compared to SNCR was almost identical for the 98% worst days regardless of the level of SO_2 emissions used. For example, in EPA's analysis the incremental improvement of SCR over SNCR for Theodore Roosevelt NP was 0.27, 0.23, and 0.28 deciview, respectively, for 2006, 2007 and 2008. The ARS analysis found incremental improvements of 0.28, 0.26, and 0.28 deciview, respectively, for 2006, 2007 and 2008. Moreover, ARS did not perform additional CALPUFF simulations for this analysis, but only combined estimates of extinction contributions from different CALPUFF simulations.

Comment: EarthJustice stated that that we aggregated Colstrip Units 1 and 2 for assessing visibility benefits of SNCR, but arbitrarily kept our assessment of benefits of SCR segregated by unit.

Response: We disagree. Modeling was performed in the same manner for SCR as for SNCR. The modeling protocol, results, and final report were available in the docket. Our evaluation of the visibility benefits was made in consideration of all of the modeling results, which includes a visibility improvement assessment for application of SCR at Colstrip Units 1 and 2 individually, as well as an assessment of the total visibility benefit from application of SCR at both units collectively.

Comment: A commenter stated that we failed to examine the collective visibility benefit of SCR in combination with SO_2 upgrades at Colstrip Units 1 and 2.

Response: We examined the individual benefits of NO_X and SO_2 controls to be able to assess the difference between pollutant-specific control options. Our evaluation of the visibility benefits was made in consideration of all of the modeling results.

Comment: EarthJustice stated that their contractor (ARS) performed AERMOD simulations to evaluate the impacts of Colstrip SO_2 emissions relative to the 1-hour average SO_2 National Ambient Air Quality Standard (NAAQS) and reported modeled violations of the SO_2 NAAQS.

Response: EPA will address compliance with the 1-hour average SO_2 NAAQS separately from Regional Haze requirements. It is beyond the scope of this rulemaking. It will be addressed by EPA at a later date.

Comment: Holcim commented that EPA discarded all prior modeling and developed a new modeling analysis in 2011. Holcim stated that EPA did not explain why it used a new modeling analysis and that EPA's BART conclusions are therefore based on modeling that is not transparent and not available for review.

Response: We disagree. As we explained in our proposal, we used CALPUFF modeling to evaluate emissions control scenarios that were consistent with the application of control scenarios for the Montana sources that were subject to BART. We did this because we were unable to obtain the modeling files from some of the sources and we wanted each source to be modeled consistently. The modeling protocol, final report, and all related files were available for review in the docket.

Comment: The Western Environmental Trade Organization (WETA) commented that the EPA recently approved the SIP for regional haze developed by the State of North Dakota. WETA explained that the North Dakota plan relied on extensive modeling that demonstrated emissions control technology installations at certain facilities would result in insignificant improvement in visibility. WETA requested that the EPA develop a visibility plan for Montana that offers the same flexibility and cost-effective standards included in North Dakota's plan.

Response: WETA did not explain what flexibility it was seeking; therefore, we are not able to evaluate whether such flexibility could be accommodated. To the extent that WETA is stating that our proposed requirements are not cost-effective, we disagree. To the extent that WETA is stating that we are being inconsistent with decisions we made for regional haze in North Dakota, we disagree. We have responded to more specific comments on the cost-effectiveness of controls elsewhere.

Comment: The commenter stated that EPA's proposed BART determinations for Colstrip Units 1& 2 are erroneous because EPA's modeling failed to include actual air quality measurements, including visual quality measurements, in its inputs to its regional haze model. The commenter further stated that real air quality data for Class I areas is critical to determining what the degree of visibility improvement may be in a given Class I area.

Response: EPA used ambient monitoring data to evaluate the CMAQ and CAMx grid model simulations that were used for modeling the uniform rate of progress toward natural visibility conditions. However, the commenter appears to be referring specifically to the CALPUFF model simulations used to evaluate visibility impacts of BART sources. The BART Guidelines require that visibility impacts from BART sources be evaluated in comparison to natural visibility conditions. The procedures used to estimate natural visibility conditions are described in the ''Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule.'' [8] It would be

[8] Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule, U.S. Environmental Protection Agency, September 2003.

inappropriate to use ambient monitoring data for current degraded visibility conditions in the evaluation of BART source visibility impacts. EPA previously considered and responded to the comment that current visibility conditions should be used in BART source evaluations in 40 CFR part 51, appendix Y, promulgated at 70 FR 39104. EPA considered the approach of assessing a BART-eligible source's impacts on visibility by using current or near-term future conditions, and EPA determined that BART visibility impacts should be evaluated in comparison to natural background visibility. In the final rulemaking EPA wrote:

> Using existing conditions as the baseline for single source visibility impact determinations would create the following paradox: The dirtier the existing air, the less likely it would be that any control is required. This is true because of the nonlinear nature of visibility impairment. In other words, as a Class I area becomes more polluted, any individual source's contribution to changes in impairment becomes geometrically less. Therefore the more polluted the Class I area would become, the less control would seem to be needed from an individual source. We agree that this kind of calculation would essentially raise the ''cause or contribute'' applicability threshold to a level that would never allow enough emission control to significantly improve visibility. Such a reading would render the visibility provisions meaningless, as EPA and the States would be prevented from assuring ''reasonable progress'' and fulfilling the statutorily-defined goals of the visibility program. Conversely, measuring improvement against clean conditions would ensure reasonable progress toward those clean conditions.

70 FR 39124.

Therefore, EPA correctly used estimates of natural visibility conditions in our evaluation of BART source visibility impacts, and we disagree with the comment that we failed to appropriately use air quality data at Class I areas.

Comment: EarthJustice stated that they do not agree with EPA's approach to use the fifth factor in determining the degree of visibility improvement from emissions control technologies where EPA adds an additional incremental benefit factor with an apparent but unstated threshold for improvement sufficiency that is contrary to the purpose and direction of the CAA.

Response: We disagree that we only evaluated visibility benefit on an incremental basis and that we used a threshold for improvement sufficiency. In the proposed FIP, we included tables showing the visibility improvement for control options as compared to baseline conditions. Incremental improvement can be easily calculated from the data in the tables, however, we did not calculate this separately for each option. In addition, our modeling protocol, modeling report and tables of results were included in the docket.

Comment: Commenters stated that we used incorrect baselines for modeling impacts from sources at Corette and Colstrip.

Response: We explain our rationale for the chosen baseline periods in responses to other comments.

B. General Comments on BART

Comments: Montana Department of Environmental Quality (MDEQ) stated that EPA should have used a dollar-per-deciview ($/deciview) metric rather than the $/ton metric to evaluate BART and reasonable progress. MDEQ argued that the use of deciviews is consistent with the Regional Haze Rule, which expresses Reasonable Progress Goals (RPGs), baseline visibility, current visibility conditions and natural conditions in deciviews. MDEQ also referenced both the BART Guidance and the Reasonable Progress Guidance to support this argument.

The NPS stated that one of the options suggested by the BART Guidelines to evaluate cost-effectiveness is cost/deciview and that the NPS believes that visibility improvement must be a critical factor in any program designed to improve visibility. The NPS stated that compared to the typical control cost analysis in which estimates fall into the range of $2,000–$10,000 per ton of pollutant removed, spending millions of dollars per deciview to improve visibility may appear extraordinarily expensive, but that the NPS compilation of BART analyses across the United States reveals that the average cost per deciview proposed by either a state or a BART source is $14–$18 million, with a maximum of $51 million per deciview proposed by South Dakota at the Big Stone I power plant. The NPS noted that even though it has no Class I areas, Nebraska Department of Environmental Quality has chosen $40 million/deciview as a cost criterion, which is also above the national average. The NPS compared its estimates for annual cost of adding SOFA + SCR to EPA's estimates for visibility impacts and stated that the cost-effectiveness of adding SOFA + SCR to improve visibility at the five Class I areas modeled by EPA is less than $10 million/deciview and significantly less than the $14–$18 million/deciview national average of BART proposals and determinations.

Response: For BART, the BART Guidelines require that cost effectiveness be calculated in terms of annualized dollars per ton of pollutant removed, or $/ton. 70 FR 39167. MDEQ and the NPS are correct in that the BART Guidelines allows for the $/deciview ratio as an additional cost effectiveness metric that can be employed along with $/ton for use in a BART evaluation. However, the use of this metric further implies that additional thresholds or notions of acceptability, separate from the $/ton metric, would need to be developed for BART determinations. We have not used this metric for BART purposes because (1) It is unnecessary in judging the cost effectiveness of BART, (2) it complicates the BART analysis, and (3) it is difficult to judge. The $/deciview metric has not been widely used and is not well-understood as a comparative tool. In our experience, $/deciview values tend to be very large because the metric is based on impacts at one Class I area on one day and does not take into account the number of affected Class I areas or the number of days of improvement that result from controlling emissions. In addition, the use of the $/deciview suggests a level of precision in the CALPUFF model that may not be warranted. As a result, the $/deciview can be misleading. We conclude that it is sufficient to analyze the cost effectiveness of potential BART controls using $/ton, in conjunction with an assessment of the modeled visibility benefits of the BART control. Within the context of reasonable progress, the Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, states that ''[y]ou should evaluate both average and incremental costs.'' [9] This is consistent with the approach under BART. As commenters note, the guidance then stated that ''simple cost effectiveness estimates based on a dollar-per-ton calculation may not be as meaningful as a dollar-per-deciview calculation, especially if the strategies reduce different groups of pollutants.'' However, the guidance makes this statement on the basis that ''different pollutants differently impact visibility impairment.'' That is, for example, a one ton reduction in SO_2 would have a greater visibility benefit than a one ton reduction of coarse mass. As only SO_2 and NO_X controls were evaluated for the reasonable progress point sources, the use of the $/deciview is not particularly

Can be found at: *http://www.epa.gov/ttncaaa1/t1/memoranda/rh_envcurhr_gd.pdf.*

[9] Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, U.S. Environmental Protection Agency, June 1, 2007, p.5–2.

relevant or informative. In addition, we did not use the $/deciview metric for our evaluation of reasonable progress controls for largely the same reasons as stated above for BART controls.

Comment: The NPS stated that we used inconsistent criteria in selecting BART controls.

Response: We disagree. As explained later, pursuant to 40 CFR 51.308(e)(1)(ii)(A) we considered the following five factors in our analysis: The cost of compliance; the energy and nonair quality environmental impacts; any pollution control equipment in use at the source; the remaining useful life of the source; and the degree of improvement which may be reasonably anticipated to result from the use of such technology. The Regional Haze Rule defines BART as the best system of continuous emission control technology available and associated emission reductions achievable, as determined through an analysis of these five factors. The NPS is correct in that the BART Guidelines allows for the $/deciview ratio as an additional cost effectiveness metric that can be employed along with $/ton for use in a BART evaluation of the five statutory factors. 70 FR 39126 to 70 FR 39127. While the Regional Haze Rule may not prevent us from establishing a bright line for some of the factors such as cost-effectiveness and visibility, we are not required to do so, and have not done so for this action as the cost and visibility factors are both weighed in making control decisions. Also, while the BART Guidelines allows for the $/deciview ratio as an additional cost effectiveness metric that can be employed along with $/ton for use in a BART evaluation, we have not used this metric in our evaluation. As explained in our determinations for each source, the cost effectiveness of controls on a dollar per ton basis and the visibility benefit of those controls were the two factors that had the most influence over our decision.

Comment: MDEQ stated that in the North Dakota Regional Haze SIP/FIP, coal-fired utilities with much greater estimated visibility impact were required to install controls similar to those required at Colstrip 1 and 2.

Response: We disagree that certain BART determinations from the North Dakota Regional Haze SIP/FIP are appropriate comparisons to our BART determinations in this FIP. Our determination on the NO_X BART determinations at Milton R. Young Station Units 1 and 2 and Leland Olds Station Unit 2[10] is explained in our final action for regional haze for North Dakota. 77 FR 20893. Our BART determinations were made on a source-specific basis in consideration of the five statutory factors.

Comment: MDEQ stated that we ''accept, discard or include new cost information without reason or justification.'' MDEQ supported this claim by arguing that we used Integrated Planning Model (IPM) data in one instance, but used costs provided by sources and an outside consultant instead of IPM data for the North Dakota Regional Haze SIP/FIP.

Response: The BART Guidelines provide some flexibility in how to calculate and consider costs. 70 FR 39127. Generally, we followed a reasonable and supported approach. We have responded to specific comments regarding our cost analysis in other responses.

Comment: MDEQ stated that the averaging times and compliance demonstrations for Colstrip 1 & 2, Corette and Devon Energy are not practically enforceable, and therefore counter to the BART Guidelines. MDEQ stated that the 30-day rolling average particulate matter (PM) emission limits for Colstrip 1, Colstrip 2 and Corette, and the NO_X limit for Devon are not enforceable with an annual stack test.

Response: We disagree with some aspects of this comment and have made changes in the final FIP to clarify requirements in response to other aspects of this comment. In the proposed FIP, we concluded that annual stack tests, along with emissions monitoring in accordance with the applicable Compliance Assurance Monitoring (CAM) plan are sufficient to determine compliance with BART PM limits. 77 FR 24099 (April 20, 2012). In its comments, MDEQ provides no evidence to the contrary aside from the general statements about practical enforceability described in the comment above. With regard to the Devon Energy Reasonable Progress determination, we have revised the monitoring, recordkeeping and reporting requirements in the final FIP. We have also clarified in a correction notice that the PM limits listed at 40 CFR 52.1396 are not based on a 30-day average. 77 FR 29270.

Comment: MDEQ noted that Cross-State Air Pollution Regulation (CSAPR) trading programs were recently determined by EPA to be an alternative to source-by-source BART determinations. 77 FR 33642 (April 20, 2012). MDEQ argued that, because CSAPR is a health-based standard, ''EPA in the East is advocating the position that Montana has taken for our own state: Realize the benefits (including visibility) from health-based standards and make compliance with those standards the demonstration for BART.''

Response: Emissions trading programs and other alternative programs can be used in place of source specific BART controls ''as long as the alternative provides greater reasonable progress towards improving visibility than BART.'' 77 FR 33644. Because Montana is not within the geographic areas covered by CSAPR, and because the State did not submit an emissions trading program or alternative program that was subject to, let alone satisfied, the ''greater reasonable progress'' test, EPA does not agree that compliance with other standards may replace a BART demonstration for sources subject to BART in Montana.

Comment: A commenter claimed that our elimination of best emission controls based on incremental benefit is not legally supportable and that EPA's analyses do not satisfy the purpose or the regulatory requirements for BART determinations. The commenter stated that we applied additional filters with unstated thresholds or standards in our consideration of BART and that those filters eliminate or significantly diminish the weight and importance of the required five factors. The commenter stated that EPA used an incremental benefit test and reached a subjective conclusion.

Response: We disagree that our determinations are not legally supportable. Pursuant to 40 CFR 51.308(e)(1)(ii)(A) we considered the following five factors in our analysis: The cost of compliance; the energy and nonair quality environmental impacts; any pollution control equipment in use at the source; the remaining useful life of the source; and the degree of improvement which may be reasonably anticipated to result from the use of such technology. The Regional Haze Rule defines BART as the best system of continuous emission control technology available and associated emission reductions achievable, as determined through an evaluation of the five statutory factors. 70 FR 39126 to 70 FR 39127. While the Regional Haze Rule may allow us to establish a bright line for some of the factors such as cost-effectiveness and visibility, we are not required to do so, and have not done so for this action.

Comment: MDEQ commented that EPA makes a case for ordering the installation of control equipment for measurable emissions reductions absent a visibility improvement goal to achieve reasonable progress as measured in deciviews. MDEQ stated that one of the

[10] We presume these units are the ''coal-fired utilities'' to which MDEQ is referring.

factors to consider when determining BART is any existing pollution control technology in use at the source and that EPA may be interpreting this provision to mean BART requires the installation of any new pollution control technology that is useful for reducing emissions generally. MDEQ stated that the statute and the Regional Haze Rule are both clear that a BART determination focuses on existing pollution controls and that the suitability of additional controls for co-beneficial purposes that may be tangentially related to the National Goal is not part of the analysis. MDEQ stated that overall purpose of any SIP, including Montana's, is the control of emissions to comply with the NAAQS as set forth in 42 U.S. Code (USC) Section7410 and that the purpose of the Regional Haze Rule is to control emissions that cause or contribute to visibility impairment in Class I Federal areas. MDEQ stated that, ''Montana is adamant on this point because it forms the basis for its reluctant renunciation of authority over Montana's BART program.'' MDEQ stated that, ''the consideration of a co-benefit strategy is not without merit, but the imposition of BART is set forth very clearly in statute and rule. MDEQ stated that the determination of BART has everything to do with visibility impairment and improvement, not the attainment or maintenance of the NAAQS.'' MDEQ suggested that, ''EPA limit the BART criteria to that set forth in the rule at 40 CFR 51.308(e) and refuse to propose new controls that are not calculated to fulfill BART criteria.''

Response: We disagree that we have misinterpreted the BART provision to consider any existing pollution control technology at the source. We point out that considering existing pollution control technology in use at the source does not preclude the consideration of new technology. As listed in the BART Guidelines, Step 1 of the ''Five Basic Steps of a Case-by-Case BART Analysis'' is ''Identify All Available Retrofit Technologies.'' 70 FR 39164. A footnote to the word ''All'' in this step of the BART Guidelines reads as follows; ''In identifying 'all' options, you must identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. It is not necessary to list all permutations of available control levels that exist for a given technology—the list is complete if it includes the maximum level of control each technology is capable of achieving.'' 70 FR 39164. Our analysis for each Montana source subject to BART included each of the ''Five Basic Steps of a Case-by-Case BART Analysis,'' as well as a complete five-factor analysis which included consideration of ''any existing pollution control technology in use at the source.'' Existing pollution control technology was considered when identifying available control options, when establishing a baseline for determining visibility impacts or for determining annual emission reductions for available control options. Existing pollution control technology also was considered in establishing emission limits. With regard to MDEQ's comment that we interpreted this provision to mean BART requires the installation of any new pollution control technology that is useful for reducing emissions generally, we point out that in many cases our BART determinations did not require additional pollution control technology to be installed for BART.

We also disagree that we have interpreted BART to require the installation of any new pollution control technology that is useful for reducing emissions generally, that we used criteria other that those listed at 40 CFR 51.308(e)(1)(ii)(A), or that we proposed new controls that are not calculated to fulfill BART criteria. As stated in other responses, pursuant to 40 CFR 51.308(e)(1)(ii)(A) we considered the five factors in our analysis.. The Regional Haze Rule defines BART as the best system of continuous emission control technology available and associated emission reductions achievable, as determined through an evaluation of the five statutory factors. 70 FR 39126 to 70 FR 39127. As stated in another response, at no point in the proposed FIP did we discuss public health impacts as a consideration in our analyses, as they were not. As stated elsewhere, we agree that the Regional Haze Rule is not a health-based standard, and that we are not authorized to consider public health impacts in promulgating our FIP for purposes of this action.

Comment: The NPS commented that EPA determined that the incremental visibility improvement from a control option must exceed 0.5 deciview at a given Class I area if costs exceed $5,000/ton in order to qualify as BART and stated that the NPS disagrees with this approach. The NPS stated that while the BART Guidelines do recommend estimation of incremental costs, it makes no mention of an incremental visibility improvement test. The NPS explained that if applied linearly, EPA's cost estimate of $3,235/ton for SCR would correspond to a visibility improvement of 0.32 deciview, not 0.5 deciview to justify SCR. The NPS stated that EPA concluded the benefit of SCR at Theodore Roosevelt NP is 0.4 deciview and that therefore, by EPA criteria SCR is BART for each Units 1 and 2.

Response: We disagree. We have not determined that the incremental visibility improvement from a control option must exceed 0.5 deciview at a given Class I area if costs exceed $5,000/ton in order to qualify as BART. As stated in other responses, while the Regional Haze Rule may allow us to establish a bright line for some of the factors such as cost-effectiveness and visibility, we are not required to do so, and have not done so for this action.

C. Comments on Cement Kilns

Comment: A commenter stated that we must not exempt cement kilns from BART for PM. The commenter described baseline visibility impacts from Ash Grove and Holcim and stated that the high degree of visibility impairment warrants analysis of whether PM emission limits should be lower to reflect BART.

Response: We disagree that we have exempted cement kilns from BART for PM. In our proposal, Table 35 shows that Ash Grove's greatest baseline visibility impact is 4.446 deciviews at Gates of the Mountains WA and Table 49 shows that Holcim's greatest baseline visibility impact is .980 deciview at Gates of the Mountains WA. 77 FR 24011 and 77 FR 24017. While we agree with the commenter that the baseline impacts are significant, the PM contribution to this overall baseline impact is small. In our proposal, Table 38 shows that for Ash Grove, coarse PM only contributes 0.84% and fine PM only contributes 4.77% to the overall baseline visibility impact of 4.446 deciviews. 77 FR 24013. Table 64 shows that for Holcim, coarse PM only contributes 5.79% and fine PM only contributes 12.61% to the overall baseline visibility impact of .980 deciview. 77 FR 24022. By contrast, our BART determination for Ash Grove for NO_X is anticipated to achieve a visibility improvement of 1.248 deciviews and our BART determination for Holcim is anticipated to achieve a visibility improvement of 0.424 deciview. Any visibility improvement that could be achieved with improvements to the existing PM controls would be negligible. BART for PM was based on using the existing control equipment and the emission limit established in each facility's Title V permit. The PM BART limits for Ash Grove and Holcim were listed in our proposal at 77 FR 24098 and are codified by our final action at 40 CFR 52.1396.

D. Comments on Ash Grove

Comment: Ash Grove stated that they did not object to EPA's conclusion that BART should be based on the installation of low NO_X burner (LNB) and SNCR. However, the company stated that they objected to the assumptions made about what SNCR can achieve. Ash Grove stated that they explained in the prior correspondence that the company did not believe that it is appropriate to assume that the Montana City kiln can achieve 50% control effectiveness. Ash Grove stated that, as the data in Table 10 of the preamble clearly showed, only one of the three kilns at Ash Grove's Midlothian plant is able to achieve 50% control effectiveness while the other two kilns had an average control efficiency of 37.7% and 40.5%.

Ash Grove also believes that no other credible evidence is provided for our conclusion as to SNCR NO_X control efficiency. Ash Grove stated that we referenced studies from other industry sectors and a marketing brochure from Cadence stating that ''control efficiency of up to 50% can be achieved on long wet kilns'' and that this quote states the upper end of what might be achievable. Ash Grove indicated that the brochure does not state that 50% control efficiency can be achieved on all long wet kilns, that Cadence's experience with SNCR on long wet kilns is what is shown in Table 10, Ash Grove indicated that Cadence was Ash Grove's partner in developing the Midlothian SNCR, which, according to Ash Grove, are the only long wet kilns in the United States with any track record of SNCR use. Ash Grove indicated that even after years of optimization on the Midlothian kilns, the data show that it has not been possible to bring all three kilns up to a 50% control efficiency and that the Midlothian NO_X reduction data reflect not only the benefits of SNCR, but also the mid-kiln firing of tires, use of a mid-kiln fan and other technologies that are not available to the Montana City kiln, but that were implemented concurrent with the SNCR installation/optimization at Midlothian to reduce NO_X emissions. Ash Grove explained that in considering the Midlothian data, one needs to account for the direct control efficiency these technologies provide, in addition to the synergistic effects of using more than one control device/technique at a time at Midlothian and that these benefits would not be available at Montana City and should not be assumed.

Ash Grove summarized that they continued to believe that a SNCR system at Montana City cannot be assumed to reach greater than 35% control efficiency and that EPA has produced no credible evidence in the record for supporting a different conclusion. Ash Grove stated that they recognized that their initial BART submittal listed 50% control as achievable for the combination of a low NO_X burner and SNCR at the Montana City kiln but since then they have realized they cannot get to that level on all three kilns at Midlothian. Ash Grove stated that they are willing to not contest the 8.0 lb/ton clinker limit, and they anticipate that compliance could require additional control technologies/strategies; therefore, they need the maximum time allowable to find ways to consistently maintain NO_X at or below that level.

Response: We disagree that SNCR cannot achieve a 50% control effectiveness at Ash Grove. The data from Ash Grove's Midlothian, Texas kilns in Table 10 of the proposed FIP, 77 FR 24003, show the SNCR control effectiveness achieved. The data were not intended to imply that this is the upper bound of what might be achieved. Ash Grove did not submit any information demonstrating that this was the maximum reduction that could have been achieved. It was not necessary to achieve greater reductions from the Midlothian Texas kilns to comply with the required emission limit. In Texas, SNCR was used at Midlothian to comply with the emission limit established at Texas Administrative Code (TAC) 117.3110(a)(1)(B) of 4.0 lb/ton clinker. TAC 117.3110(b) allowed an owner or operator of a long wet kiln to comply with the 4.0 lbs/ton clinker emission limit on the basis of a weighted average for multiple cement kilns. Thus, it was not necessary for each individual kiln to achieve the maximum percentage reduction possible; one or more kilns could emit more than 4.0 lbs/ton clinker as long as the weighted average complied with the emission limit.

Ash Grove has not submitted any data to demonstrate that SNCR was optimized in an attempt to achieve the greatest control efficiency possible. For the Midlothian kilns, from June–August 2009, the emission rate from kiln 1 was 3.7 lbs/ton clinker and the emission rate from kiln 2 was 4.8 lbs/ton clinker and from June through August 2010, the emission rate from kiln 1 was 2.6 lbs./ton clinker, the emission rate from kiln 2 was 4.8 lbs/ton clinker, and the emission rate from kiln 3 was 4.4 lbs/ton clinker. These emission rates are significantly higher than the emission rates from June to August 2008 (an average of 1.8 lbs/ton clinker for kiln 1, 2.7 lbs/ton clinker for kiln 2, and 2.7 lbs/ton clinker for kiln 3). An increase in NO_X emissions over time would not be expected if the SNCR were being optimized.

With regard to Ash Grove's claim that we need to account for the direct control efficiency of other technologies that are not available to the Montana City Kiln, the tire-derived fuel system was already being used at Midlothian in 2006 and is already accounted for in the 2006 baseline to which the 2008 post-SNCR emissions are compared.[11] Thus, no further adjustment is necessary. Ash Grove has not provided data to demonstrate that a synergistic effect has occurred between mid-kiln firing of tires and SNCR at Midlothian.

Ash Grove has not submitted data to support their claim that only 35% reduction can be achieved with SNCR at the Montana City kiln. All of the Midlothian kilns were able to achieve greater than 35% reduction with SNCR and there is no information to demonstrate that SNCR was optimized to its maximum potential. The BART Guidelines state, ''In assessing the capability of the control alternative, latitude exists to consider special circumstances pertinent to the specific source under review, or regarding the prior application of the control alternative. However, you should explain the basis for choosing the alternate level (or range) of control in the BART analysis. Without a showing of differences between the source and other sources that have achieved more stringent emissions limits, you should conclude that the level being achieved by those other sources is representative of the achievable level for the source being analyzed.'' 70 FR 39166. Ash Grove has not demonstrated the differences between their Montana City kiln and the Midlothian kilns.

With regard to Ash Grove's statement that we have not produced credible evidence in the record for supporting a greater than 35% control effectiveness for SNCR, we provided a detailed explanation in our proposed FIP at 77 FR 24003. Ash Grove has used SNCR at its Midlothian kilns where it was shown to achieve the reductions ranging from 37.7% to 62.5% and these are within the range of control effectiveness demonstrated at other kilns. Considering that control effectiveness is greater when initial NO_X concentrations are greater, and that the baseline NO_X emissions of the Montana City kiln are

[11] Letter from Molly Cagle to Chance Goodwin, Initial Control Strategy Development for DFW Ozone Nonattainment Area, July 30, 2010, p. 1.

significantly greater than the Midlothian kilns, the Montana City kiln would be expected to achieve even greater control effectiveness when compared to the Midlothian kilns. 77 FR 24003 and 77 FR 24004.

Ash Grove's comment that they are willing to not contest the 8.0 lb/ton clinker limit is noted. With regard to Ash Grove's comment that they anticipate that compliance could require additional control technologies/strategies and that therefore they need the maximum time allowable to find ways to consistently maintain NO_X at or below that level, we disagree that additional control technologies/strategies are necessary; however, the final FIP does not require specific control technologies/strategies to be used. The final FIP allows for the maximum time available to comply with the 8.0 lb/ton clinker limit.

Comment: Ash Grove stated that the company supported the conclusions as to what constitutes BART for SO_2. Ash Grove noted that in the preamble we stated that there is so little improvement in visibility associated with implementing add-on SO_2 controls that there is no basis for requiring such controls under BART. Ash Grove stated that Clean Air Act Section 169A(g)(2) clearly states that ''the degree of improvement in visibility which may reasonably be anticipated to result'' must be used in evaluating potential BART controls. Ash Grove concluded that given the nominal improvement in visibility predicted from add-on controls, there is no basis under BART for requiring the addition of such controls. Ash Grove stated that the BART program has a very narrow statutory focus in that it exclusively addresses visibility improvement and that absent a material increase in visibility, the company believes that we would have been arbitrary and capricious if we had required add-on controls for SO_2 utilizing our BART authority. Ash Grove stated that the company supported our ultimate conclusion.

Response: The comment is noted. The final FIP makes no changes to the conclusions regarding SO_2 controls for Ash Grove.

Comment: Ash Grove stated that the company supported our conclusion that existing PM controls (an electrostatic precipitator (ESP)) constitute BART and that ESPs are well-accepted controls for wet kilns. Ash Grove stated that their compliance with the filterable particulate standard in the process weight rule applicable to the kiln is an appropriate limit for ensuring that the ESP is properly operating and that annual compliance demonstrations will ensure ongoing compliance. Ash Grove stated that they believe that this approach is particularly appropriate where the contribution of PM emissions to visibility impairment is nominal.

Response: The comment is noted. The final FIP makes no changes to the conclusions regarding PM controls for Ash Grove.

Comment: Ash Grove requests clarification on whether they must comply with BART limits for SO_2 and PM within five years of the effective date of the rule, as specified in the proposed regulatory text at 40 CFR 52.1396(d), or within 180 days for SO_2 and 30 days for PM, as suggested by the preamble to the proposed rule. If the intent is to require compliance sooner than five years from the effective date, then Ash Grove requests that the rule be renoticed, and that if EPA will not allow five years from the effective date, then Ash Grove requests that the BART compliance date for these pollutants be 30/180 days after the effective date, or the Portland cement National Emission Standards for Hazardous Air Pollutants (NESHAP) compliance date, whichever is later, in order to coordinate with the implementation of EPA's Portland cement NESHAP and New Source Performance Standard (NSPS) requirements, including installation and certification of continuous emission monitoring systems (CEMS). Ash Grove stated that the monitoring that EPA is imposing as part of the concurrent Portland cement Maximum Achievable Control Technology (MACT) rulemaking is very complicated and must be able to work in concert with what EPA imposes under this BART rulemaking. Ash Grove also stated that critical components of Ash Grove's envisioned monitoring scheme, such as installation of clinker weigh belts or the development of slurry conversion mechanisms, cannot be implemented within the 180 day period after the effective date.

Response: We agree with aspects of this comment, but disagree with others. We agree that there is an omission in the proposed 40 CFR 52.1396(d). We failed to specify, in the rule language itself, the compliance deadline for SO_2 of 180 days after the effective date of the FIP, and the compliance deadline for PM of 30 days after the effective date of the FIP. These deadlines were mentioned in the rule preamble. We have corrected the rule language at 40 CFR 52.1396(d) to specify these deadlines. For both SO_2 and NO_X, we further clarify that the 180-day deadline is applicable only where installation of additional controls is not necessary to comply with the BART limit; otherwise the compliance deadline is five years after the effective date of our rule.

We disagree that the compliance deadline should be 30/180 days after the FIP effective date, or the Portland cement NESHAP compliance date, whichever is later. With regard to ''whichever is later,'' EPA does not have the option of specifying an open-ended compliance deadline for BART. In our FIP proposal at 77 FR 23993, we explained that ''Once EPA 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 the final FIP. CAA section 169(g)(4) and 40 CFR 51.308(e)(1)(iv).'' Ash Grove's comment does not dispute this explanation.

Further, Ash Grove has not presented any specific reason for us to wait on the Portland cement MACT rulemaking before imposing PM and SO_2 monitoring requirements for purposes of BART. First in regard to SO_2 monitoring, the proposed amendments to the Portland cement MACT and NSPS rules do not include any changes to the SO_2 CEMS monitoring requirements. In the proposed amendments, EPA is proposing to correct the emission rate calculation formula for SO_2 in NSPS Subpart F, at 40 CFR 60.64(c), but since we are making the same correction in our final FIP rule (see our response below to the comment on NO_X and SO_2 emission rate calculation), this is not a valid reason to wait until the Portland cement MACT and NSPS amendments are finalized before imposing SO_2 monitoring in the FIP.

Further, the proposed amended Portland cement MACT and NSPS rules require a SO_2 CEMS only if the kiln is subject to an SO_2 limit under NSPS. Ash Grove has not indicated that their kiln in Montana is subject to an SO_2 limit under NSPS, and even if it is, the proposed amended Portland cement MACT and NSPS rules will not impose any different requirements for an SO_2 CEMS than those in existing NSPS rules at 40 CFR 60.63(f), which are cross-referenced by our proposed regulatory text at 40 CFR 52.1396(e)(3). Ash Grove has also not presented any specific reason, such as vendor unavailability or site-specific complications, why it should take more than 180 days to replace and certify their SO_2 CEMS. We have already stated in our FIP proposal that 180 days would allow time for monitoring systems to be certified if necessary. We are clarifying that CEMS will have to be certified for BART purposes independent of NSPS requirements.

Second, in regard to PM monitoring, the proposed amendments to the

Portland cement MACT and NSPS rules require a PM continuous parametric monitoring system (CPMS), whereas the existing Portland cement MACT and NSPS rules require a PM CEMS. Since our FIP proposal does not require PM CPMS nor PM CEMS, the proposed amendments to the Portland cement MACT and NSPS rules do not affect the FIP and are not a valid reason to extend the 30-day compliance deadline for PM in the FIP.

With regard to Ash Grove's statement that critical components of the monitoring scheme, such as installation of clinker weigh belts or the development of slurry conversion mechanisms, cannot be implemented within the 180 day period after the effective date of the FIP, Ash Grove has not presented any specific reason why it should take longer than 180 days. With regard to Ash Grove's statement that the clinker monitoring must work in concert with the MACT rulemaking, our proposed regulatory text at 40 CFR 52.1396(e)(4)(ii) cross-references 40 CFR 60.63(b) for clinker production monitoring requirements. The proposed amendments to the Portland cement MACT and NSPS rules do not change the requirements in the existing section 60.63(b) for determining the amount of clinker produced. Only minor language clarifications are proposed, and there is no change to actual requirements.

We note that Ash Grove has no issue with the proposed PM BART emission limit. However, in preparing responses to Ash Grove's comments on other aspects of our proposed FIP, we identified a typographical error in our emission limit table for cement kilns. We made a correction to the emission limit table for cement kilns at 52.1396(c)(2), to clarify that the PM emission limit for Ash Grove is in lb/hr, not lb/ton clinker. Only the PM emission limit for Holcim is in lb/ton clinker. Similarly, we have clarified 40 CFR 52.1396(f)(2) to indicate that the emission rate of particulate matter shall be reported in lb/hr for Ash Grove, and in lb/ton clinker for Holcim. Ash Grove is not required to monitor clinker production for purposes of demonstrating compliance with the PM BART limit. We have also included in 40 CFR 52.1396(f)(2) the equation for calculating lb/ton clinker for PM at Holcim, rather than cross-reference 40 CFR 52.1396(e)(4)(ii), which pertains to SO_2 and NO_X, not PM.

Comment: Ash Grove does not object to the requirement in our proposed regulatory text at 40 CFR 52.1396(e)(3) to maintain, calibrate and operate SO_2 and NO_X CEMS on the cement kiln stack. Ash Grove requests, to be consistent with other requirements to which they are subject, that the language be revised and proposed creating an exception during CEMS breakdown, repairs, calibration checks, and zero and span adjustments.

Response: We agree it is appropriate to address the language for consistency purposes. Rather than use the language proposed by Ash Grove, we are incorporating language from 40 CFR 60.63(g), which says,

> You must operate the monitoring system and collect data at all required intervals at all times the affected source is operating, except for periods of monitoring systems malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments).

We have revised the regulatory text at 40 CFR 52.1396(e)(3) accordingly. 40 CFR 60.63(g).

Comment: Ash Grove also believes it is critical that the facility have adequate time to install, shake down and calibrate the necessary CEMS equipment. The facility currently lacks a flow meter and does not have certified CEMS. As a result, Ash Grove anticipates that it must replace its CEMS system, including the data acquisition and handling system (DAHS) as part of Portland cement MACT implementation. Ash Grove stated that this effort cannot be completed until the Portland cement MACT requirements are finalized, as Ash Grove understands that the NESHAP monitoring provisions are in flux. Therefore, Ash Grove believes that the BART CEMS requirements must be implemented at the same time that the Portland cement MACT CEMS requirements are implemented and not before.

Response: We disagree. See our response on compliance deadlines above. EPA does not have the option of specifying an open-ended compliance deadline for BART. Further, Ash Grove has not presented any specific reason, such as vendor unavailability or site-specific complications, why it should take longer than 180 days to install a flow meter and replace the CEMS system with a certified system. This comment has not resulted in any change to our proposal.

Comment: Ash Grove supports the approach whereby the CEMS data are utilized to demonstrate compliance with the NO_X and SO_2 BART limits. However, Ash Grove believes there is a material error in the formula used in the proposed regulatory text at 40 CFR 52.1396(e)(4)(ii). The formula expresses the concentrations of SO_2 and NO_X in grains per standard cubic foot (gr/scf). Ash Grove noted that a CEMS would not normally generate SO_2 or NO_X concentrations in gr/scf, but in parts per million (ppm), consistent with the requirements of 40 CFR 60, Appendix B, Performance Specification 2. Ash Grove recognizes that this formula was likely intended to match Equation 3 in the 2010 revised Subpart F NSPS. While Ash Grove appreciates the effort to maintain consistency between the requirements, Ash Grove believes that Equation 3 in the Subpart F NSPS is in error and will be corrected in the upcoming public notice addressing Subpart F. Ash Grove provided a suggested formula to replace the formula stated in the proposed regulatory text.

Response: We agree for the reasons stated by Ash Grove that the formula for calculating the emissions should express SO_2 and NO_X concentrations in ppm, not in gr/scf. We have corrected 40 CFR 52.1396(e)(4)(ii) accordingly; however, rather than use the language proposed by Ash Grove, we have used the formula and associated language found in the proposed amendments to the Portland cement NSPS. 77 FR 42397.

Comment: Ash Grove noted that the proposed regulatory text at 40 CFR 52.1396(f) would require that Ash Grove perform EPA Method 5, 5B, 5D or 17, 40 CFR Part 60, Appendix A, to demonstrate compliance with the PM limit and that the test consist of three runs with each run at least 120 minutes long and each run collecting a minimum sample of 60 dry standard cubic feet. Ash Grove supports the approach of identifying the specific source test methods in the rule. However, Ash Grove does not support specifying the duration of each test run and the minimum sample size. Ash grove stated that this BART FIP is being implemented with the intent that it will control emissions for many years to come. Ash Grove stated that placing this type of detailed data into the rule, rather than letting the test duration and sample size be determined based on the test method as it exists at the time of the test, invites future confusion and trouble. Therefore, Ash Grove suggested that EPA specify the test methods but delete the other language relating to the test duration and sample size.

Response: We disagree. The test method does *not* determine the test duration and sample size, but cross-references other rules in this regard. EPA Method 5 states in subsection 8.2.4, ''Select a total sampling time greater than or equal to the minimum total sampling time specified in the test procedures for the specific industry, such that (1) the sampling time per point is not less than 2 minutes (or some greater time interval as specified by the Administrator), and (2) the sample volume taken (corrected to standard conditions) will exceed the required minimum total gas sample volume.'' Methods 5B and 5D cross-reference Method 5 for sampling time and sampling volume. Method 17 does not cross-reference Method 5 for sampling time and sampling volume, but does not specify anything different. We consider three test runs, with each run at least 120 minutes long, and each run collecting a minimum sample of 60 dry standard cubic feet, to be appropriate and necessary for purposes of the Montana Regional Haze FIP. We note that this has been specified in PM stack testing requirements in other regional haze FIPs. (See, for example, Proposed Final FIP by EPA Region 9 for the Four Corners Power Plant, 76 FR 52387, August 22, 2011.) This comment has not resulted in any change to our proposal.

Comment: Ash Grove stated that the proposed regulatory text at 40 CFR 52.1396(h)(6) would require that they maintain, among other things, records required by Part 75. Ash Grove is not subject to part 75 as that applies only to electrical generating units. Ash Grove believes that this reference to Part 75 was just a ''catch-all'' and not intended to impose any obligations under Part 75 upon cement kilns otherwise not subject to Part 75. However, due to the potential for misunderstanding and the lack of relevance of the Acid Rain provisions to cement kilns, Ash Grove requested that the reference to Part 75 be deleted.

Response: We agree. Since the proposed monitoring requirements for cement kilns, at sections 52.1396(e)(3) and (4), and at section 52.1396(f)(2), do not cross-reference Part 75, there are no applicable Part 75 recordkeeping requirements under our FIP proposal. Therefore, the reference to Part 75 on recordkeeping, at 40 CFR 52.1396(h)(6), is not necessary and has been removed.

Comment: Ash Grove stated that the proposed regulatory text at 40 CFR 52.1396(i) would require that Ash Grove submit quarterly excess emission reports and CEMS performance reports. Ash Grove currently is subject to similar reporting requirements under the Title V and NESHAP programs. However, in both of those programs the reports are submitted semi-annually, not quarterly. Ash Grove sees no purpose gained by submitting the reports quarterly and the additional administrative burden is significant. Therefore, Ash Grove requested that EPA revise this reporting requirement to make it consistent with the similar reports submitted under Title V and NESHAP programs, i.e., semiannual reports.

Response: We agree. We used provisions in NSPS Subparts A and F applicable to cement kilns as a model for the CEMS-related reporting requirements for cement kilns in our FIP proposal. The general provisions of NSPS Subpart A, at 40 CFR 60.7(c), require semiannual excess emission reports and monitoring systems performance reports, except when more frequent reporting is specifically required by an applicable subpart, or if the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. NSPS Subpart F for cement kilns does not specify more frequent reporting. Therefore, we have revised the required reporting frequency to semiannual in 40 CFR 52.1396(i)(1) and (i)(2) for cement kilns. The required reporting frequency for EGUs remains quarterly.

Comment: Ash Grove requested that EPA revise its proposed regulatory text at 40 CFR 52.1396(i)(2)(ii) requiring the company to submit Relative Accuracy Audits (RAAs) and Cylinder Gas Audits (CGAs). Ash Grove does not object to the idea of submitting Relative Accuracy Test Audits (RATAs) as those are documented in a highly formalized test report prepared by a third party testing contractor. However, the RAAs and CGAs are not documented in the same type of formal third party report. Ash Grove believes that it is adequate to certify that the audits have been performed as part of the semiannual reports.

Response: We disagree. Our proposed regulatory text at 40 CFR 52.1396(e)(3) states that the CEMS shall be used to determine compliance with the emission limitations in section 52.1396(c), for each unit, in combination with data on actual clinker production. For cement kilns, 40 CFR section 52.1396(i)(2)(ii) requires submittal of results of any CEMS performance tests required by 40 CFR part 60, appendix F, Procedure 1, which is titled ''Quality Assurance Requirements for Gas Continuous Emission Monitoring Systems Used for Compliance Determination.'' Under Section 7 of Procedure 1 (Reporting Requirements), it is not adequate to merely certify that the RAAs and CGAs have been performed. Section 7 requires submittal of a Data Assessment Report for each quarterly audit, which must include ''Assessment of CEMS data accuracy and date of assessment, as determined by a RATA, RAA or CGA described in Section 5, including * * *, the A [accuracy] for the RAA or CGA, the RM [reference method] results, the cylinder gases certified values, the CEMS responses, and the calculations results as defined in Section 6.'' This information must be included in the semiannual reports referenced in our response to the previous comment above. We consider this information appropriate and necessary. This comment has not resulted in any change to our FIP proposal.

Comment: Ash Grove requested that EPA drop the requirement proposed in 40 CFR 52.1396(k)(2) to provide semiannual progress reports on construction of SO_2 and NO_X control equipment. Ash Grove does not object to filing notification of commencement of construction as this obligation is consistent with what Ash Grove is used to under the NSPS and state new source review program. However, semiannual construction progress reports are not something that Ash Grove is typically set up to generate and there seems to be little gained from such reports. Therefore, Ash Grove requested that this requirement be dropped from the rule.

Response: We disagree. We consider construction progress reports necessary as part of ensuring that BART sources meet their five-year compliance deadlines. Since installation of substantial equipment may be involved, there could be unforeseen construction delays that we would want to be aware of well before the five-year deadline. We do not consider this reporting a burdensome requirement, as our FIP proposal does not specify any particular level of detail for these progress reports. This comment has not resulted in any change to our FIP proposal.

Comment: Ash Grove noted that the BART limits are identified as applying at all times, including startup, shutdown and malfunction. Although the preamble states that the proposed limits allow ''for a sufficient margin of compliance,'' Ash Grove argued that these limits do not take into account the impact of sudden and unforeseen effects attributable to malfunctions. As compliance with all three limits (i.e., SO_2, PM and NO_X) could be affected by a malfunction, Ash Grove believes that it is appropriate for EPA to provide the same affirmative defense in the event of a malfunction as is provided in the Portland cement MACT rules. Specifically, Ash Grove requested that EPA incorporate the same affirmative defense provided in 40 C.F.R. 63.1344 to address malfunctions.

Response: EPA disagrees with this comment. As stated in our proposal, to determine the BART NO_X limit for Ash

Grove, we first applied the efficiency of the selected controls, LNB + SNCR at 58%, to the 99th percentile 30-day rolling average NO_X emission rate at this facility for May 26, 2006 through September 8, 2008, resulting in a figure of 7.82 lb/ton clinker. 77 FR at 24007 n.45. We then set the BART limit above this, at 8.0 lb/ton clinker. Ash Grove provides no data to show that, at this facility, this limit cannot be achieved due to malfunctions, or that our use of the 99th percentile 30-day rolling-average NO_X emission rate in combination with the additional margin (from 7.82 to 8.0 lb/ton clinker) provides an insufficient margin of compliance.

For SO_2, we did not select any additional controls for BART. We based the BART SO_2 limit on the 99th percentile 30-day rolling average SO_2 emission rate at this facility for May 26, 2006 through September 8, 2008, 11.02 lb/ton clinker, and set the BART limit at 11.5 lb/ton clinker. 77 FR at 24013 n.73. Ash Grove provides no data to show that, at this facility, this limit cannot be achieved due to malfunctions, or that our use of the 99th percentile 30-day rolling average SO_2 emission rate at this facility in combination with the additional margin (from 11.02 to 11.5 lb/ton clinker) provides an insufficient margin of compliance.

We also did not select any additional controls for PM. Ash Grove currently has an electrostatic precipitator for PM control and is subject to a process weight-based PM_{10} emission rate set out in Montana's approved SIP and Ash Grove's title V operation permit. We set the BART limit, based on use of the current control technology, at the existing emission rate. Ash Grove has not provided any data to show that it is not able to meet the existing limit due to malfunctions. As a result, we continue to maintain that the NO_X, SO_2, and PM BART limits for Ash Grove provide for a sufficient margin of compliance, including taking into account malfunctions.

With respect to the Portland cement MACT standard, we note that the MACT standard applies across the entire source category, while the BART limits imposed in this FIP reflect application of the five statutory BART factors to a particular facility, Ash Grove. Ash Grove does not explain why, in this circumstance, the existence of the affirmative defense in the MACT standard necessarily implies an affirmative defense is required for the BART limits, which as discussed above, for NO_X and SO_2 are based in part on actual emissions from Ash Grove, and for PM are based on an existing limit for Ash Grove. We therefore disagree that the affirmative defense provided for in 40 CFR section 63.1344 should be also provided for in this FIP.

Comment: The opening sentence of the proposed regulatory text at 40 CFR 52.1396(i) states ''All reports under this section, with the exception of 40 CFR 53.1395(n) and (o) shall be submitted * * *'' Ash Grove believes that this cross-reference is in error, as Ash Grove is not aware of there being a 40 CFR 53.1395(n) or (o). Ash Grove believes this was intended to cite to 40 CFR 52.1396(n) and (o).

Response: We agree this was an error. We have corrected the language to cite to section 52.1396(n) and (o), instead of section 53.1395(n) and (o).

E. Comments on Holcim

Comment: Montanans Against Toxic Burning (MATB) applauded our proposed retrofit of the Holcim kiln to include LNB and SNCR.

Response: We acknowledge MATB's support.

Comment: MATB believes that we should reanalyze the fuel-switching option for the Holcim cement kiln. Specifically, they stated that petroleum coke inputs should be reduced, which they believe would lead to significant reductions in SO_2 emissions. They also stated that our analysis may be skewed by what MATB describes as Holcim's ''low-ball'' estimates of its sulfur emissions. MATB believes that a review of Holcim's past monitoring data could lead to a different conclusion.

Response: We disagree that it is necessary to reanalyze fuel switching options for Holcim. In our analysis, we used annual SO_2 emissions as reported to the National Emissions Inventory and we have no reason to believe that these were underestimated. The annual emissions (50.2 tpy) are so minimal that fuel switching options resulting in increased annual cost would not be considered cost-effective on a dollar per ton basis. In addition, the visibility improvement from fuel switching is very low at 0.015 deciview for fuel switching option 1 and 0.024 deciview for fuel switching option 2.

Comment: MATB commented that a ''real-time hourly'' standard for NO_X and SO_2, rather than the 30-day rolling averages based on clinker production proposed, is needed to assure compliance with protective limits. MATB explained that with the 30-day rolling averages, spikes due to malfunction or improper operation will ''disappear'' in the averaging process.

Response: We assume that by ''real-time hourly'' standard, the commenter means an emission limit in pounds per hour. We disagree that we should establish an hourly standard rather than a 30-day rolling average limit based on clinker production. As we explained in our proposal (77 FR 24007), we chose an output-based standard because it avoids rewarding a source for becoming less efficient, i.e., requiring more feed to produce a unit of product. An output-based standard promotes the most efficient production process. With regard to 30-day versus hourly averaging time, EPA's BART guideline calls for BART emission limits to be expressed as 30-day rolling averages for electrical generating units. 70 FR 39172. We believe this is appropriate for other BART units as well. The proposed limit allows for a sufficient margin of compliance for a 30-day rolling average limit that would apply at all times, including startup, shutdown, and malfunction. 77 FR 24018.

Comment: MATB believes that more oversight, transparency, and accountability are needed when it comes to reporting and record keeping.

Response: We are confident that the information used to make our decision is accurate. With regard to reporting and recordkeeping requirements under the FIP, the commenter has not explained what oversight, transparency and accountability is lacking and what more is needed in this regard. That said, section 114 of the CAA allows EPA and the State to ask for monitoring data and reports as necessary. These documents are available to the public unless the information is claimed to be confidential business information.

Comment: MATB commented that the efficiency of Holcim's ESP is incorrect as stated in EPA's analysis, and does not operate during most malfunctions. These malfunctions can last 24 hours or more. Additionally, MATB stated that EPA's analysis fails to consider PM during periods of startup, shutdown and malfunction and considering the frequent upsets with the Trident kiln, that cause its ESP to be turned off, an additional control measure at Holcim is essential. MATB encouraged us to analyze the addition of a fabric filter.

Response: We disagree that it is necessary to evaluate the installation of a fabric filter at Holcim. In our proposal, we explained that PM emissions from Holcim did not significantly contribute to visibility impairment. We used actual emission rates to model the visibility impact from Holcim. Because the baseline visibility impact from PM was low, improvements to the existing PM control device would not be significant.

Comment: The commenter stated that an annual three-hour stack test is inadequate to monitor PM emission limit compliance.

Response: We disagree. The proposed requirements for demonstrating compliance with PM emission limits include more than just an annual three-hour stack test. ''In addition to annual stack tests, owner/operator shall monitor particulate emissions for compliance with the BART emission limits in accordance with the applicable Compliance Assurance Monitoring (CAM) plan developed and approved in accordance with 40 CFR part 64.'' 77 FR 24099. The requirements include the following:

- 40 CFR 64.3(a) requires that a monitoring parameter be selected by the owner/operator as an indicator of emission control performance for the control device.
- 40 CFR 64.3(b) requires that an indicator range for that parameter be selected ''such that operation within the range provides a reasonable assurance of ongoing compliance with emission limitations or standards for the anticipated range of operating conditions.''
- 40 CFR 64.7(d) requires the owner/operator, upon detecting an excursion or exceedance of the CAM indicator range, to restore operation of the emitting unit and emission control device to its normal or usual manner of operation as expeditiously as practicable, in accordance with good air pollution control practices for minimizing emissions.
- 40 CFR 64.8 says the Administrator or permitting authority may require the owner/operator, in the event of repeated excursions or exceedances of the CAM indicator range, to develop and implement a Quality Improvement Plan, to correct any control device performance problems.

Further, 40 CFR 52.11396(l) states, ''At all times, owner/operator shall maintain each unit, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions'' This applies to all sources in the FIP.

Comment: MATB explained that there are inconsistencies in EPA's proposed NO_X and SO_2 emissions limits, and there appears to be a mistake on Table 53 dealing with fuel-switching options.

Response: These inconsistencies were corrected in the FR notice dated May 17, 2012. 77 FR 29270.

Comment: Holcim commented that that the output-based standards we proposed reward a source for operating inefficiently. Holcim indicated that our proposed FIP is unfairly stringent with respect to Holcim as compared to Ash Grove. They stated that the kiln types and capacities of the two plants are substantially equal, but that Holcim's emissions profiles are notably different. Holcim stated that they use proper kiln design and best combustion practices to control NO_X emissions at their plant, and that Ash Grove has NO_X emissions that are 42% higher than NO_X emissions from the Holcim plant. Holcim further stated that our proposed FIP rewards Ash Grove with a NO_X BART emission limit that is 60% higher than Holcim's proposed NO_X BART emission limit. Holcim pointed out that their kiln has substantially lower current NO_X emission rates, lower current visibility impacts, and a lower subsequent visibility improvement, yet our FIP requires substantially tighter emission limits for NO_X and SO_2.

Holcim commented that, based on EPA's analysis, the proposed NO_X limit would require Holcim to invest a total of $5.6 million in SNCR and indirect firing, which would result in an improvement in visibility at Gates of the Mountains WA that is significantly less than the 1.0 deciview perceptibility threshold and that our proposed FIP would require only a $1.19 million capital investment from Ash Grove, even though Ash Grove's impact on Gates of the Mountains WA is more than double the impact from Holcim. Holcim also stated that we estimated that Ash Grove's NO_X emissions caused degradation in visibility of greater than 0.5 deciview at Gates of the Mountains WA on approximately 33% of the days in the baseline period while Holcim impacted Gates of the Mountains WA at greater than 0.5 deciview only on approximately 4% of the days during the baseline period. Holcim stated that EPA's approach would reward Ash Grove's higher emissions and inefficient operation by creating an economic disadvantage for Holcim in a highly competitive market.

Response: We disagree. Our explanation in the proposed FIP regarding the output-based standard was provided to explain the difference between a standard expressed in quantity of pollutant per amount of feed and quantity of pollutant per amount of product produced. As explained in our proposal, an output-based standard avoids rewarding a source for becoming less efficient, i.e., requiring more feed to produce a unit of product. 77 FR 24007. Our explanation did not imply that both sources should have exactly the same emission rate. The NO_X standards for both Holcim and Ash Grove were determined by applying the control efficiency of the selected technologies to the current emission rates at each facility. This is the most appropriate method to determine emission limits for these two sources. As explained in other responses, we are not requiring Holcim to convert to indirect firing in the final FIP, so the information comparing capital investment is no longer relevant. In the final FIP, we have determined the emission rate for Ash Grove by applying the control effectiveness of LNB + SNCR (58%) to the current emission rate and as explained in other responses we have revised the emission rate for Holcim by applying the control effectiveness of SNCR (50%) to the current emission rate. In both cases, we have determined the emission rate based on the control effectiveness of the control technology that was chosen based on the five statutory BART factors listed at CAA section 169A(g)(2) and 40 CFR 51.308(e)(1)(ii)(A). The five statutory factors include the costs of compliance and visibility improvement; therefore, these factors were evaluated and considered in the selection of controls. Applying the control effectiveness of the technology that was identified based on the five statutory factors to the current emission rates for each source is a logical method for determining emission rates. This same methodology was used for determining the emission rates for both sources.

We note that in the final FIP, Ash Grove will reduce an estimated 1,088 tons per year of NO_X using LNB+SNCR at a total annual cost of $2,238,893, but Holcim will only reduce an estimated 556 tons per year of NO_X at a total annual cost of $650,399. Ash Grove will be reducing 946 tons per year of NO_X through the operation of SNCR, but Holcim will only be reducing 556 tons per year through the operation of SNCR.[12] We provide this information to demonstrate that overall, more emissions will be reduced by Ash Grove and to also illuminate the fact that annual cost will be greater for Ash Grove. The cost of reagent is proportional to the amount of pollutant removed; therefore, annual reagent cost will be significantly greater for Ash Grove.

We are not requiring additional controls for SO_2 for either Holcim or Ash Grove and the SO_2 limits for each facility were determined based on current emission rates. This determination was based on an evaluation of the five statutory factors and the SO_2 emission rates were determined in the same manner for both

[12] See Table 11, FR 77 24004, and Table 22, 77 FR 24007 for Ash Grove. Holcim's baseline NO_X emissions are 1,112 tpy. Revised emissions reduction for SNCR only for Holcim is 556 tpy and cost is $1,170/ton.

facilities. There is no necessity for additional SO_2 control at either facility; the current controls were considered to be BART.

As for Holcim's comment that the proposed FIP rewards Ash Grove's higher emissions and inefficient operation by creating an economic disadvantage for Holcim in a highly competitive market, the BART Guidelines do allow for the consideration of unusual circumstances that justify taking into consideration the conditions of the plant and the economic effects of requiring the use of a given control technology. The BART Guidelines state:

> [t]hese effects would include effects on product prices, the market share, and profitability of the source. Where there are such unusual circumstances that are judged to affect plant operations, you may take into consideration the conditions of the plant and the economic effects of requiring the use of a control technology. Where these effects are judged to have a severe impact on plant operations you may consider them in the selection process, but you may wish to provide an economic analysis that demonstrates, in sufficient detail for public review, the specific economic effects, parameters, and reasoning.

70 FR 39171. Holcim did not provide information for us to consider in such an analysis.

The BART Guidelines also state, ''[a]ny analysis may also consider whether other competing plants in the same industry have been required to install BART controls if this information is available.'' 70 FR 39171. In this case, Ash Grove is required to install BART controls. We have considered each plant individually, and based on the BART analyses both Holcim and Ash Grove plants are required to install BART controls.

Comment: Holcim argued that the Texas kilns cited by EPA in the FIP are not representative and two of the three kilns did not achieve 50% NO_X reduction. Holcim cited several site-specific factors that impact SNCR performance that they state EPA did not adequately consider, including turbulent mixing, heat transfer, spray droplet size, spray drop evaporation, devolatilization and others. Holcim also argued that the carbon monoxide (CO) levels at the Trident kiln are much lower than the CO levels at the Texas kilns, which will adversely impact NO_X reductions and ammonia slip at the Trident kiln relative to the Texas kilns. Holcim additionally argued that EPA did not adequately consider NO_X emissions variability in setting the limit because of the limited time frame considered for the data from the Texas kilns.

Response: We disagree. EPA has assumed that 50% reduction is possible with SNCR; however, this does not rule out the possibility that Holcim may determine that other means, such as mid-kiln firing, may be better than SNCR alone in terms of cost or other factors for achieving 50% NO_X reduction. In any event, 50% NO_X reduction is achievable with SNCR and this is supported by the data cited in the proposed FIP. We address this in more detail in a response to Ash Grove.

Holcim also noted that SNCR performance depends upon a wide range of site-specific factors. They list rate-limiting processes, including turbulent mixing, heat transfer, spray droplet size, spray drop evaporation, devolatilization and others. As detailed in a contractor's report in the docket, we have considered these factors and none of them causes us to change our decision. In brief, spray droplet size is a factor the SNCR system designer can control and tailor to the needs of the system. Turbulent mixing may or may not be within the SNCR system designer's ability to control, but in any case our selection of SNCR does not depend on optimal turbulent mixing.

With respect to CO concentration, if the CO at the Trident kiln is much lower than at the Texas kilns referred to in the comments, as Holcim describes, this simply means that the SNCR reagent should be introduced at a point in the process where the gas temperature is higher than the injection point used at the Texas kilns where the CO levels are higher. This may in fact improve SNCR performance.

With regard to NO_X emission variability raised by Holcim, first, the data used by EPA in Table 10 of the proposed FIP cover a three month period which should be adequate time to address normal operating changes that would impact NO_X. Second, SNCR can be used to mitigate variability in NO_X emissions. This is confirmed by the data on the Midlothian kilns that is in the proposed FIP and as described in response to comments from Ash Grove. For every kiln, the standard deviation in the monthly NO_X emission rate was lower after the application of SNCR than before, indicating a lower variation in NO_X emissions.

Comment: Holcim argued that a detached plume may result from operation of the SNCR in the winter months, which will make it necessary to not operate the SNCR system or to allow a condition where visibility is adversely impacted to continue. The detached plume could be the result of the formation of ammonium salt reactions with sulfate or chlorides.

Response: We disagree. As discussed by Miller,[13] there are several factors that could contribute to a visible detached plume, and these include moisture, temperature, and availability of the constituents that contribute to the plume—ammonia, sulfates and chlorides. Ammonia slip from the SNCR process can be well controlled in a cement kiln, and the SNCR system would not affect the amount of ammonia contributed by raw materials.

Sulfates and chlorides are largely the result of impurities in the raw materials, and ammonia can be contributed by raw materials. Holcim's SO_2 emissions are low indicating low levels of sulfates in the exhaust. Therefore, the risk of an ammonium sulfate plume, even with ammonia present, is small. The presence of chlorides will depend upon the raw materials and whether the chlorides become bound to alkaline material before being emitted up the stack.

Chlorides, if present, will typically preferentially be bound to alkaline material that is present rather than be emitted. Holcim did not provide any information on stack chloride emission levels at this site to support their concerns about detached plume from ammonium chloride.

Because of the importance of impurities in the raw materials in contributing to the chemical constituents that form a plume, the experience at one kiln cannot be directly applied to another without more information. Therefore, while there may be a risk of a visible plume at the Trident kiln, Holcim has not provided enough data to indicate that addition of an SNCR system would increase this risk significantly. Furthermore, a localized plume would not necessarily impact a Class I area and Holcim has not provided any information indicating such an impact.

Comment: Holcim indicated that EPA failed to consider the NO_X control technology already installed at the Trident plant. Holcim explains that they changed the burner at Trident in May 2009 to a multichannel LNB design as part of the company's burner system modification for NO_X control, as detailed in Holcim's 2007 BART analysis.

Holcim stated that EPA's BART analysis ignored the installation of the multichannel LNB at the Trident plant, in contravention of EPA's obligation to consider ''any existing pollution control

[13] Miller, F. M., ''Management of Detached Plumes in Cement Plants'' 2001 IEEE–IAWPCA Cement Industry Technical Conference Vancouver, British Colombia, Canada April 2001.

technology in use at the source'' as part of the five-factor BART analysis. 42 U.S.C. 7491(g)(2). Holcim's BART analysis was prepared and submitted in 2007, before the multichannel LNB technology was installed.

Holcim explains that they originally installed a multichannel burner in April 2008 but it caused operational issues and was removed in July 2008. The multichannel burner was redesigned, installed in May 2009, and has operated continuously since that time. According to Holcim, the multichannel design allows the fuels to be separated into different channels and enables Holcim to more precisely control the amount of air passing through each of the channels. Consequently, Holcim says, they can better control the flame characteristics in the kiln, which results in higher thermal efficiency of the kiln and improved product quality.

Holcim stated that they also anticipated that the multichannel design would reduce NO_X and SO_2 emissions. Holcim acknowledges that the effects of the technology are difficult to quantify. Based on a comparison of NO_X emissions pre- and post-installation of the LNB technology where the fuel mix was generally the same, Holcim says the plant's NO_X emissions decreased by approximately 13% with the installation of the multichannel LNB. In addition to the multichannel LNB, Holcim stated that they installed an indirect firing system for the petroleum coke system.

Holcim notes that EPA used a baseline for the Trident plant of years 2008 through 2011, a period of time that already includes the effects of the LNB technology at the plant. Holcim stated that EPA assumed in its BART proposal for the Trident plant that the combination of LNB and indirect firing would achieve a NO_X reduction of 15%. However, Holcim stated that a 13% reduction in NO_X emissions has already been achieved through prior installation of the multichannel LNB. Holcim states there is no basis to assume that indirect firing would improve NO_X emissions reductions at Trident and that additional NO_X reductions can only be obtained through installation of SNCR. As a result, Holcim concludes that EPA's analysis of the cost-effectiveness and visibility impact for the installation of indirect firing is, ''clearly erroneous and should be disregarded''.

Response: We agree with aspects of this comment, but disagree with others. As described in more detail below, Holcim has not provided enough information to demonstrate that the installed multi-channel burner that Holcim installed is in fact a low NO_X burner. In any case, the baseline used for the BART analysis included emissions averaged over a four year period (2008–2011), which would have included the time that the multi-channel burner was installed. We have decided that the incremental cost of indirect firing and a low NO_X burner is not justified and have revised the BART emission limit accordingly.

We agree that our BART proposal, did not consider installation of the new burners that Holcim describes as ''multichannel LNB'' in its March 20, 2008 letter to Vickie Walsh of the MDEQ. As the June 9, 2009 letter from Holcim to EPA notes, ''a low NO_X burner modification would require low primary air and, thus, a conversion of Trident's firing system from a direct to an indirect system.'' Based on the information we have, it appears that the Trident kiln has not installed an indirect firing system for coal and therefore the multichannel burner does not meet the definition of LNB in Holcim's letter. The burner is not capable of operating at low primary air levels on pulverized coal and cannot achieve the NO_X reductions that an indirect firing system would achieve.

However, we disagree that we must credit the newly installed burner with a 13% reduction in NO_X emissions, because we are lacking validation data that such a reduction has been achieved. Holcim has only presented summary information to support the claim of 13% reduction and has not provided the underlying data to validate its claim. Our examination of NO_X emissions data provided by Holcim on March 2, 2012, covering the period from 2008 through 2011 (referenced in our proposal at 77 FR 24018, footnote 93), does not reveal any evidence of sustained NO_X emission reduction after May of 2009. We have used data from the time period 2009–2011, after the new burner was installed, in calculating baseline emissions. 77 FR 24014, Table 39, footnote 1. This baseline accurately reflects current conditions and is appropriate for comparison to available control scenarios.

Nevertheless, since a switch to indirect firing to accommodate installation of LNB, as described in our FIP proposal, would have an unreasonably high incremental cost-effectiveness of $8,029/ton, with minimal visibility benefits (see our response below), we are not requiring a switch to indirect firing and LNB as BART in the final FIP. We also are clarifying that we intended this option to include switching to indirect firing and a LNB. We have recalculated the proposed BART limit for NO_X to reflect a 50% reduction in NO_X emissions from that baseline by addition of SNCR alone, rather than the 58% reduction we previously used, which reflected switching to indirect firing and adding a LNB plus SNCR.

In recalculating our proposed BART emission limit for NO_X, we continue to rely on the estimate of baseline NO_X emissions in lb/ton clinker provided in Holcim's 2012 submittal, cited in our proposal at 77 FR 24018, footnote 93. That submittal listed a 99th percentile 30-day rolling average NO_X emission rate of 12.6 lb/ton clinker, for the period 2008–2011. Applying a 50% reduction to the 99th percentile figure yields 6.3 lb/ton clinker. To allow for a sufficient margin of compliance for a 30-day rolling average limit that would apply at all times, including startup, shutdown and malfunction (as explained in our proposal at 77 FR 24018), we are setting the BART limit at 6.5 lb/ton clinker in our final rule.

Since the estimated baseline NO_X emissions have not changed from our proposal, and since our estimate of 50% NO_X reduction for SNCR alone has not changed from our proposal, our estimate of 556 tons per year of expected NO_X reduction for SNCR alone has also not changed from our proposal.

Comment: Holcim stated that EPA underestimated the costs of installing and maintaining a SNCR system. Holcim stated that the company calculated the direct annual costs of SNCR to be $443,341 and the indirect annual costs for SNCR to be $227,538, and that these calculations employed a 15-year amortization schedule, as requested by EPA in 2007.[14] Holcim noted that EPA's estimated direct annual costs and indirect annual costs for SNCR are lower than Holcim's estimates by approximately 67% and 46%, respectively and suggested that the difference may be at least in part due to EPA's use of a 20-year period in the proposal.

Holcim stated that it is unclear how EPA derived its numbers and that EPA provided no explanation in the FIP proposal. Holcim requested clarification of EPA's method for calculating these costs and urged EPA to instead use the cost calculation numbers provided by Holcim.

Also, Holcim stated that if EPA reviews selective catalytic reduction (SCR) for cement kilns in subsequent reasonable progress planning periods, and determines that Holcim must install SCR instead of SNCR at that time then

[14] August 2009 Submittal (EPA–R08–OAR–2011–0851–0038); Letter from Callie A. Videtich to Ned Pettit (Nov. 26, 2007) (EPA–R08–OAR–2011–0851–0038).

the 20-year amortization for SNCR costs would not accurately reflect the annual costs of installing SNCR. Holcim also stated that since the company conducted its original analysis, Holcim has installed SNCR at its plant in Hagerstown, Maryland in 2011, which also has a long kiln. Holcim stated that the total capital costs for the SNCR installation at Hagerstown were approximately $1,920,000, including the cost of commissioning and spare parts and that, in addition, Hagerstown budgeted $591,000 for 2012 operating costs ($1.35 per metric ton of clinker or $1.23 per metric ton of cement). Holcim stated that actual operating costs for 2012 through the end of April have been $179,000 ($1.40 per metric ton of clinker or $1.28 per metric ton of cement). Holcim anticipates that similar capital and operating costs would apply to the installation of SNCR at Trident. Holcim requested that EPA use these updated figures in its analysis of the costs of SNCR at Trident.

Response: We agree with aspects of this comment, but disagree with others. We note that the letter to which Holcim refers requested that Holcim reanalyze annualized costs using a 15-year amortization period for a scrubber, not SNCR. We agree that EPA underestimated the cost of SNCR and that clarification on cost is needed, but we disagree with the statement that EPA provided no explanation in its proposal on how EPA derived its cost numbers. We also disagree with the statement that EPA provided no explanation for use of a 20-year amortization period. We also disagree with the statement that SNCR costs at the Trident kiln should be similar to Holcim's Hagerstown kiln.

We agree that we underestimated the cost of SNCR and that clarification is needed. The underestimate arose from our omission of cost of reagent. In Holcim's August 12, 2009 submittal, two versions of a SNCR cost spreadsheet were included. In one version, Holcim redacted the line item for reagent cost, on the basis of a Confidential Business Information (CBI) claim. This was the version we used for our proposal. However, in its cover letter for the August 12, 2009 submittal, Holcim stated that it later retracted its CBI claim. So the submittal included a second version of the same SNCR cost spreadsheet, in which the reagent line item now appears. The reagent cost is listed by Holcim in this second version at $379,183.

We have recalculated the annual costs of SNCR to include the cost of reagent. Relying on the second version of the cost spreadsheet in Holcim's August 12, 2009 submittal, we now calculate the annual costs other than capital recovery at $526,471 and the total annual cost, including capital recovery, at $650,399. Using an estimated emission reduction of 556 tons per year of NO_X, as we did in our proposal (which is a 50% reduction from the NO_X emissions baseline of 1,112 tons per year), we have recalculated the cost-effectiveness of SNCR at $1,170/ton. At this cost-effectiveness, we still consider SNCR to be BART for NO_X. Holcim has given us no reason to think otherwise.

We disagree with the statement that EPA provided no explanation in its proposal on how EPA derived its cost numbers. We explained that we relied on cost estimates supplied by Holcim for capital costs and annual costs of SNCR, with the exception of the Capital Recovery Factor (CRF) used. 77 FR 24015. We included a footnote to Table 44 to explain that we relied on Holcim's capital cost estimate for SNCR. We included a second footnote to that table to explain what CRF we used. We also included a footnote to Table 45 to explain that we relied on Holcim's estimate of direct annual operating costs. 77 FR 24016.

We disagree with the statement that EPA provided no explanation for use of a 20-year amortization period. As explained at 77 FR 24015, we relied on Holcim's estimates of SNCR capital cost and annual costs, with the exception of the capital recovery factor (CRF). We acknowledge that we wrote to Holcim in 2007 to recommend 15-year amortization, and that our decision since then to use 20-year amortization instead needs clarification. We now clarify that after reviewing EPA national guidance on CRFs in more detail since 2007, we determined that it would be more appropriate to use a CRF consistent with 20 years for the useful life of the kiln and associated SNCR controls. As explained below, our use of a 20-year period was not arbitrary.

The guidance we relied on was EPA's Air Pollution Control Cost Manual (CCM), which says, in regard to SNCR, that ''In general, indirect annual costs (fixed costs) include the capital recovery cost, property taxes, insurance, administrative charges, and overhead. Capital recovery cost is based on the anticipated equipment lifetime and the annual interest rate employed. An economic lifetime of 20 years is assumed for the SNCR system.'' EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B–02–001, January 2002, Section 4.2, Chapter 1, page 1–37. We explained in our FIP proposal that without commitments for an early shutdown, EPA cannot consider a shorter amortization period. 77 FR 24014. For consistency in comparing control options for NO_X and SO_2 for all Montana BART sources, our FIP proposal uses a 20-year equipment life in all the BART analyses (provided that the equipment life of each control option is 20 years or more). The CRF for a 20-year equipment life and 7% discount rate (the latter being recommended in Office of Management and Budget (OMB) Circular A–4, which we cited at 77 FR 24016) is 0.0944. As shown in Table 44 at 77 FR 24016, we multiplied Holcim's estimated capital cost of $1,312,800 by this CRF to yield a capital recovery cost of $123,928.

With regard to Holcim's comment that a 20-year amortization would misrepresent actual costs in the event that SCR rather than SNCR were to be required in the next planning period, we cannot anticipate every event that might happen in the future and we are not required to do so in establishing an amortization period.

We disagree with the statement that SNCR costs at the Trident kiln should be similar to Holcim's Hagerstown kiln. The Trident kiln is much smaller than the Hagerstown kiln. The Trident kiln is permitted at 425,000 tons per year of clinker production. Montana Air Quality Permit #0982–11, Condition II.B.6. The Hagerstown kiln is rated at 630,114 tons per year of clinker production capacity. Prevention of Significant Deterioration (PSD) Permit Application for Approval, Holcim Hagerstown, October 30, 2008. Also, the Hagerstown kiln—a dry kiln—likely has different emission rates than the Trident kiln. Without more information, it is not possible to determine how much of the claimed $1,920,000 capital cost of the Hagerstown kiln SNCR system, as well as operating costs, would be costs that are permissible for inclusion in a BART cost estimate. For these reasons, without more information, the costs of the SNCR system at the Hagerstown kiln are not useful for estimating the costs at the Trident kiln. Therefore, we continue to rely on the SNCR capital cost estimate of $1,312,800 and operating cost estimate of $147,288 for Trident, already supplied to us by Holcim in the August 2009 submittal. We also note that, even with a capital cost of $1,920,000, it appears SNCR would remain cost-effective; Holcim has provided no reason why our BART selection would change. This comment has not resulted in any changes to our regulatory text for NO_X BART.

Comment: Holcim indicated that EPA underestimated the costs of installing indirect firing at Trident. Holcim stated that the company did not include indirect firing in its 2007 BART analysis and did not consider indirect firing to be an appropriate technology to evaluate to achieve NO_X reductions at Trident. Holcim stated that at EPA's request, the company submitted an estimate to EPA of the costs of installing indirect firing at Trident.[15] Holcim stated that in EPA's own analysis, the Agency ''inexplicably and arbitrarily'' eliminated a significant portion of the costs from Holcim's analysis. Nonetheless, even using EPA's underestimated costs for the installation of indirect firing and mistaken assumption that indirect firing could reduce NO_X emissions at Trident by 15%, neither the average cost-effectiveness of indirect firing nor the incremental cost-effectiveness of indirect firing warrant a determination that indirect firing should be selected as BART.

Holcim pointed out that EPA is proposing to require that Holcim install both SNCR and indirect firing at Trident based on its analysis of the average cost-effectiveness of installing both technologies together. Holcim stated that the overwhelming majority of NO_X emissions reductions and improvements in visibility would result from the installation of SNCR alone and that by ignoring the incremental costs of SNCR + indirect firing, and focusing solely on the average cost effectiveness, Holcim states that EPA tries to make the costs of SNCR + indirect firing appear reasonable. Holcim stated that the average cost-effectiveness for the installation of SNCR at Trident is well within the range of what EPA has considered for BART, but that EPA estimated the average cost effectiveness of indirect firing to be $4,279/ton, which is far outside the range of what EPA has considered to be reasonable for BART. With such high costs for indirect firing, the incremental cost-effectiveness of SNCR + indirect firing as compared to SNCR alone is $8,029/ton. Holcim stated that EPA should consider both the average and incremental cost effectiveness of its BART analysis for Trident. Holcim stated that, although EPA clearly identified the incremental cost effectiveness of SNCR + indirect firing, EPA ''inexplicably ignored this unreasonable figure in concluding that the combination of technologies constitutes BART for Trident''. Holcim stated that the incremental cost effectiveness of SNCR + indirect firing is unreasonable given the slight to nonexistent improvement in visibility that it would achieve and that EPA should eliminate this combination of technologies as BART.

Holcim further stated that, based on modeling, the installation of indirect firing and SNCR at Trident, even if it could achieve EPA's claimed 58% reduction in NO_X emissions, would result in an improvement of visibility of only 0.424 deciview in Gates of the Mountains WA and that this does not constitute a significant or perceptible improvement in visibility. Holcim stated that EPA's conclusion is even more unjustifiable considering the actual percentage reduction that Trident could be expected to achieve with the installation of SNCR of approximately 35% on an annual average basis.

Finally, Holcim stated that the average cost effectiveness estimates for indirect firing alone ($4,279/ton) and for SNCR + indirect firing ($1,528/ton) are well above what EPA used as a cost-effectiveness threshold for NO_X in the Cross-State Air Pollution Rule (CSAPR), which EPA promulgated last year to address health-based standards. Holcim stated that the company does not understand why EPA believes it appropriate to use a higher cost threshold for an aesthetic standard than it has for a health-based standard.

Response: We agree with aspects of this comment, but disagree with others. We agree that an incremental cost effectiveness of $8,029/ton, for LNB/indirect firing + SNCR, versus SNCR alone makes LNB/indirect firing + SNCR unreasonable for BART at the Trident kiln.

As explained in a previous response above, we have removed switching to indirect firing and a LNB from consideration as an option for further reducing NO_X emissions and are treating any NO_X emission reduction that may have been achieved from installation of a new burner as part of the emissions baseline. We have recalculated the proposed BART limit for NO_X to reflect a 50% reduction in NO_X emissions from that baseline by addition of SNCR alone, rather than the 58% reduction we previously used, which reflected a switch to indirect firing and a LNB plus SNCR. The recalculated NO_X BART limit is 6.5 lb/ton clinker.

We disagree, however, with the statement that EPA analyzed for indirect firing as a separate control option. We did not. Throughout our proposal, we refer to the control option as LNB and are now clarifying that this option was intended to include switching to indirect firing and a LNB. We explained at 77 FR 24015 that the capital cost estimate of $4,385,307 for LNB includes the cost of converting from a direct to an indirect firing system to accommodate LNB, including installation of a baghouse, additional explosion prevention, pulverized coal storage, and dosing equipment. We cited Holcim's additional response of August 2009 as the source of this information.

We disagree with the statement that SNCR could be expected to achieve only a 35% reduction in NO_X emissions. See our response to Holcim's comment above.

We also disagree with the statement that any controls required by our action must demonstrate a perceptible visibility improvement. In a situation where the installation of BART may not result in a perceptible improvement in visibility, the visibility benefit may still be significant. The July 6, 2005 BART Guidelines state:

> even though the visibility improvement from an individual source may not be perceptible, it should still be considered in setting BART because the contribution to haze may be significant relative to other source contributions in the Class I area. Thus, we disagree that the degree of improvement should be contingent upon perceptibility. Failing to consider less-than-perceptible contributions to visibility impairment would ignore the CAA's intent to have BART requirements apply to sources that contribute to, as well as cause, such impairment.

70 FR 39129. Visibility impacts below the thresholds of perceptibility cannot be ignored because regional haze is produced by a multitude of sources and activities which are located across a broad geographic area.

With regard to Holcim's comment comparing the cost-effectiveness of controls required under the CSAPR, with cost-effectiveness of controls required under the Regional Haze Rule and the BART Guidelines, we reject the comparison. The two rules address different requirements of the CAA.

Comment: Holcim agreed with EPA's proposal that no additional controls constitute BART for SO_2 at Trident but objected to the imposition of a 30-day SO_2 limit. In Holcim's view, imposing a 30-day limit is neither reasonable nor necessary. Holcim's Trident plant relies on inherent scrubbing to achieve its extremely low SO_2 emissions. EPA's modeling confirms that SO_2 emissions from Trident have effectively zero visibility impact. Trident could more than double its current SO_2 emissions and still not have any reliably predictable impact on visibility (less than 0.1 deciview). Even if all SO_2 emissions from Trident were eliminated, visibility would improve in Gates of the Mountains WA by less than 0.05 deciview; less than one-twentieth of a perceptible change in visibility. See

[15] Letter from Greg Gannon to Laurel Dygowski, June 9, 2009. (See EPA–R08–OAR–2011–0851–0038).

77 FR at 24021. *Id.* at 24021, Table 63. Holcim stated that the kiln could not increase its emissions sufficiently to affect visibility without exceeding its currently enforceable limit. Consequently, Holcim stated that there simply is no need to impose short term SO_2 limits to protect visibility.

Second, Holcim stated that because Trident relies on inherent scrubbing to control SO_2, the plant has no real control over the short-term emissions variability that results from the natural variability in limestone from its quarry. The emissions variability would never rise to a level that could affect visibility, but it could cause Trident to exceed the proposed 30-day limit. Thus, the only effect of the 30-day limit would be to impose unnecessary regulatory burdens on the plant and expose it to potential penalties for short-term emissions variability, over which Holcim has no control and which would not impact visibility.

Holcim also commented that EPA is proposing to impose an SO_2 limit that is not based on the installation of retrofit control technology or a process change and that offers no improvement in visibility. Holcim stated that because the proposed limit is based on current emissions and will not improve visibility, it cannot be considered BART; the CAA and EPA's own BART Guidelines require that, in determining BART, the Administrator consider the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. Holcim requested that EPA eliminate its proposed 30-day SO_2 limit as it does not represent BART and would impose unnecessary regulatory burdens and new compliance risks while serving no visibility purpose.

Response: We disagree. The July 6, 2005 BART Guidelines state that ''* * * you must establish an enforceable emission limit for each subject emission unit at the source and for each pollutant subject to review that is emitted from the source.'' 70 FR 39172. Our FIP proposal states that ''States, or EPA if implementing a FIP, 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.'' 77 FR 23993. Similarly, the BART Guidelines identify SO_2, NO_X and PM as visibility-impairing pollutants. 70 FR 39160. Since these pollutants are subject to review, emission limits must be established. This comment has not resulted in any changes to our proposal. We note that Holcim has not provided any specific data to demonstrate that they may exceed the emission limit established for SO_2.

Comment: Holcim disagreed with EPA's proposal to impose an emission limit for PM at Trident of 0.77 lb/ton clinker. Holcim stated that the proposed limit, which is based on Trident's current emissions, is unjustified because it would result in no visibility impact and that as the company had already explained, the selected BART must consider the degree of improvement in visibility. Holcim stated that adding a duplicative applicable requirement to Trident's Title V permit would serve no purpose other than to ''create the potential for multiple penalties if the requirement were violated.''

Response: See the previous response.

F. Comments on CFAC

Comments: CFAC requested that EPA conduct a BART analysis for their facility now, rather than in the future, so that CFAC has more information for planning a restart. The NPS commented similarly. CFAC also commented that not knowing what the BART controls may or may not be for their facility makes it difficult to know whether those controls could be installed within the five-year timeframe. Another commenter stated that we must either set BART limits for CFAC in the FIP, or we must require plant shutdown as part of the FIP.

Response: We disagree that it is necessary to conduct the BART analysis at this time. The information necessary to complete such a BART analysis is not available until CFAC's future operational plans are known. The requirements for CFAC at 40 CFR 52.1396(n) are sufficient at this time. With regard to CFAC's comment that not knowing what the BART controls may or may not be for their facility makes it difficult to know whether those controls could be installed within the five-year timeframe, the BART Guidelines state that we must require compliance with emission limits no later than five years following the final FIP. 70 FR 39172. CFAC can provide the necessary information to EPA to conduct a BART analysis at any time.

G. Comments on Colstrip Units 1 and 2

Comment: A commenter stated that PPL's modeling files related to the June 2008 Addendum to PPL Montana's Colstrip BART Report should be placed in the docket.

Response: We requested the modeling files from PPL and PPL responded that they could not locate those files. We based our decisions on the more recent modeling described at 77 FR 24002.

Comment: Commenters stated that they object to our proposed BART determinations for NO_X and SO_2 because it would impose emission limits based on SNCR and an additional scrubber vessel, respectively. Commenters stated that EPA's proposed BART analysis for Colstrip Units 1 and 2 is inconsistent with our statutory obligations and our own Guidelines. Commenters suggested that our BART determinations contain significant errors. Commenters stated that we did not properly or correctly consider the costs of the proposed controls, the incremental cost-effectiveness of the controls, and the lack of any reasonably expected visibility improvements resulting from the proposed controls. Instead of the BART proposed by EPA, commenters supported the installation of SOFA for NO_X control with an emission limit of 0.20 lb/MMbtu, and lime injection for SO_2 control with an emission limit of 0.20 lb/MMBtu (both as a 30-day rolling average).

Response: In proposing our BART determinations, we met the statutory requirements under section 169A of the CAA and also followed the BART Guidelines. Based on our consideration of the five statutory BART factors, we continue to find that BART for NO_X is SOFA+SNCR with an emission limit of 0.15 lb/MMBtu (30-day rolling average). Similarly, based on our consideration of the five statutory BART factors, we continue to find that BART for SO_2 is lime injection and an additional scrubber vessel with an emission limit of 0.08 lb/MMBtu (30-day rolling average). Each specific issue raised by the commenters is addressed in a separate response to comments.

Comment: Several commenters asserted that EPA's costs for SNCR on Colstrip Units 1 and 2 were inaccurate and that SNCR is not cost effective. Commenters asserted that this was due to a number of errors, including use of an incorrect baseline, overstating the emission benefits that can be achieved with SNCR, and using improper cost estimation techniques. The commenters submitted their own cost estimates challenging those reported by EPA.

Response: EPA estimated a cost effectiveness for SNCR+SOFA of about $1,550/ton. This estimate has been confirmed after the proposal through information supplied by SNCR vendors.[16] For this control combination, Nalco Mobotec Inc. (Mobotec) estimated a cost effectiveness of roughly $1,395/ton, while Fuel Tech Inc. (Fuel Tech) estimated a cost effectiveness of $1,642/

[16] Memo from Jim Staudt, Andover Technology Partners, to Doug Grano, July 10, 2012.

ton. The average vendor cost effectiveness of $1,518/ton is slightly lower than what was previously estimated by EPA. Likewise, EPA estimated a cost effectiveness for SNCR (after SOFA) of about $3,300/ton. For SNCR (after SOFA) Nalco Mobotec estimated a cost effectiveness of roughly $2,800/ton, while Fuel Tech estimated a cost effectiveness of $3,500/ton.[17] The average vendor cost effectiveness of $3,150/ton is slightly lower than what was previously estimated by EPA.

Further, the cost effectiveness of SNCR is of course highly dependent on the emission benefits that the control technology can achieve. The discrepancy between our cost effectiveness and that supplied by the commenters is largely driven by this factor. We address this issue, as well as other issues raised by commenters in regard to our SNCR cost estimates for Colstrip Units 1 and 2, separately below.

Comment: Two commenters claimed that EPA used an incorrect baseline of 2008–2010 for Colstrip pollutant emissions in our BART analyses. One commenter stated that the BART Guidelines require a baseline for BART analyses of 2000–2004, while another stated it requires a baseline of 2001–2003. Both of these baseline periods were prior to the installation of additional combustion controls at Colstrip Units 1 and 2. In addition, one commenter claimed that the 2008–2010 baseline emissions are not representative as they reflect a period of economic downturn.

Response: We disagree with these comments. The BART Guidelines require you to choose a representative baseline period, but do not specify that this period must be 2000–2004 or 2001–2003:

> The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period.

70 FR 39167.

As we discussed in our proposed rule, in 2007 PPL installed additional combustion controls on Colstrip Units 1 and 2 in order to meet new Acid Rain Program emission limits. As these controls were not installed to meet BART requirements, we find that it is appropriate to reflect them in the baseline emissions.

Furthermore, annual heat input data contained in the CAMD emissions system shows the baseline period of 2008–2010 is representative of the operation of the Colstrip Unit 1 and 2. For example, the 2000–2010 annual heat input for Colstrip Unit 1 ranged from a low of 24,003,758 MMBtu/yr in 2006 to a high of 30,770,151 MMBtu/yr in 2004. The 2008–2010 annual average heat input used by EPA in our BART analysis of 26,578,089 MMBtu/yr falls about in the middle of this range. Therefore, the baseline period chosen by EPA is a realistic depiction of the heat input (and thereby annual emissions) of the Colstrip Units 1 and 2.

Finally, the 2000–2004 annual average heat input (the period that one commenter asserted we should have used), was 26,966,516 MMBtu/yr, and only slightly higher than the heat input used by EPA of 26,578,089 MMBtu/yr. Therefore, even if we had used the 2000–2004 heat input, it would not have affected the BART analysis in a meaningful way.

Comment: Commenters asserted that EPA overstated the emissions benefit of SNCR and that it cannot achieve the level of control claimed. The commenters stated that SNCR cannot achieve a 25% emission reduction. They also stated that SNCR (in combination with combustion controls) cannot achieve an emission limit of 0.15 lb/MMBtu on a 30-day rolling average.

PPL based their assertions on analyses which they obtained from SNCR vendors, Nalco Mobotec, Inc. and Fuel Tech Inc. They stated that these analyses show that the lowest feasible emissions limit for these units on a 30-day rolling average would be in the range of 0.17 to 0.18 lbs/MMBtu. PPL estimates that only a 10% reduction in NO_X emissions could be achieved since ammonia slip must be limited to 0.5 ppm.

NPS questioned whether SNCR can achieve 0.15 lb/MMBtu on a 30-day rolling average due to the sensitivity of SNCR to boiler operation, size, and configuration. NPS did not provide any data or information to support their concerns other than to state that a query of the CAMD emissions system revealed only two EGUs that are consistently meeting 0.15 lb/MMBtu on monthly basis.

Response: We disagree that we have overstated the emissions benefit of SNCR. Neither the vendor analyses nor the SNCR performance data contained in the CAMD emissions system support a conclusion that we overstated the emission benefits of SNR.

The vendor analyses provided by PPL confirm the assumptions made by EPA regarding the emissions benefits that can be achieved with SNCR. Both vendors indicate that a control efficiency of 25%, as assumed by EPA, can be achieved. For example, Fuel Tech indicates that a ''10 ppm ammonia slip would result in ~25% NO_X reduction.'' [18] Similarly, Mobotec indicates that ''[a]t 7 ppm of ammonia slip, NO_X emissions could be reduced up to 25%, provided there would be no impact on the performance of the air preheater, or other plant systems.'' [19] We realize that the control efficiency of SNCR is highly dependent on the level of ammonia slip. However, we find no reason that an ammonia slip level of 5 to 10 ppm is unacceptable for the Colstrip Unit 1 and 2. These levels of ammonia slip are typical for SNCR. In fact, Fuel Tech stated that ''[i]n the coal-fired Utility market segment, the SNCR systems have been historically designed for a minimum of 5 ppm ammonia slip with some lower sulfur applications with NH_3 slip levels of 10 ppm.'' [20] (We address the potential impacts from ammonia slip in a separate response to comments).

Further, we note that the control efficiencies provided by the vendors are for operation at full load, and that higher control efficiencies can be achieved at lower loads. For instance, Mobotec relates that ''[h]igher NO_X reductions can be achieved at mid to low load heat inputs, possibly up to 40%.'' [21] Given that the Colstrip Unit 1 and 2 frequently operate at below full load, it is likely that on an annual basis SNCR can achieve better than the 25% emission reduction assumed by EPA.

PPL has erred in stating that the control efficiency of SNCR is no more than 10% since ammonia slip levels must be limited to 0.5 ppm. The commenter bases this claim on what they believe to be a precedent set in the Centralia Power Plant BART determination. However, the Centralia BART determination prepared by Washington stated that, ''TransAlta's cost analysis uses a urea-based SNCR system providing a nominal 25% reduction in NO_X levels with a 5 ppm ammonia slip.'' [22] And as established by the vendor analyses discussed above, much higher emission reductions than 10% can be achieved with SNCR at ammonia slip levels of 5 to 10 ppm.

[17] Id.

[18] Letter from Dale T Pfaff, Fuel Tech, Inc. to Gordon Criswell, PPL Montana, May 29, 2012.

[19] Letter from Gary Tonnemacher, Mobotec, to Gordon Criswell, PPL Montana, May 25, 2012.

[20] Fuel Tech, May 29, 2012.

[21] Mobotec, May 25, 2012.

[22] BART Determination Support Document for Transalta Centralia Generation LLC Power Plant, Centralia, Washington, Prepared by Washington State Department of Ecology, Revised November 2011, p. 14; Region 10 clarified the typographical error in their **Federal Register** notice via email from Steve Body to Aaron Worstell dated July 26, 2012.

Similarly, the performance data contained in CAMD emissions system only serves to reinforce the assumptions made by EPA regarding the emission benefits of SNCR. Based on our review of the CAMD emissions data, there are many EGUs equipped with SNCR (with combustion controls) that are achieving an emission rate of 0.15 lb/MMBtu or lower on a monthly basis. One unit in particular, Boswell Unit 4, is very comparable to the Colstrip Unit 1 and 2. Boswell Unit 4, like the Colstrip Unit 1 and 2, burns sub-bituminous coal and is tangentially fired. In addition, Boswell Unit 4 had a baseline annual emission rate (with LNB and CCOFA, but prior to the installation of SNCR and SOFA) similar to the Colstrip Unit 1 and 2 of approximately 0.35 lb/MMBtu. Since the installation of full combustion controls and SNCR, the Boswell Unit has achieved a monthly emission rate of below 0.15 lb/MMBtu. For example, between April 2011 and April 2012, the most recent full year of emissions data available in the CAMD emissions system, the monthly emission rates for Boswell Unit 4 were between 0.11 and 0.14 lb/MMbtu. This is a strong indicator of the performance rates that can be expected for Colstrip Units 1 and 2.

We acknowledge that a range of performance rates are currently being achieved with SNCR, and are in some cases not as low as at Boswell Unit 4. However, without a showing that there are circumstances unique to the Colstrip Unit 1 and 2 that would prevent SNCR from achieving the same reductions as at Boswell Unit 4, we find no reason that an emission limit higher than 0.15 lb/MMBtu on a 30-day rolling average is warranted. This is consistent with the BART Guidelines:

> Without a showing of differences between the source and other sources that have achieved more stringent emissions limits, you should conclude that the level being achieved by those other sources is representative of the achievable level for the source being analyzed.

70 FR 39166.

Finally, due to the smaller size of Colstrip Unit 1 and 2 (333 MW each), we expect that SNCR would be more effective than at Boswell Unit 4 (525 MW). This is because the effectiveness of SNCR on large boilers is somewhat reduced as the relatively larger cross-section of the boiler makes distribution of the reagent difficult.

For the reasons stated here, we find no basis in claims that we overestimated the emission benefits for SNCR.

Comment: Commenters stated that EPA did not properly consider the incremental cost-effectiveness of SNCR at Colstrip Units 1 and 2. Commenters stated that EPA improperly assessed the costs of SNCR when combined with SOFA, and not as an individual technology. Commenters stated that the incremental cost of adding SNCR to SOFA outweighs the benefits. One commenter cited portions of the BART Guidelines that address consideration of incremental costs between competing technologies.

Response: We disagree with these comments. We addressed why these control technologies were analyzed together in our proposed rule:

> The post-combustion control technologies, SNCR and SCR, have been evaluated in combination with combustion controls. That is, the inlet concentration to the post-combustion controls is assumed to be 0.20 lb/MMBtu. This allows the equipment and operating and maintenance costs of the post-combustion controls to be minimized based on the lower inlet NO_X concentration.

77 FR 22043.

If we had not combined the control technologies, then the cost effectiveness would have been more favorable to SNCR. This is because the inlet to the SNCR would reflect the current annual baseline emissions (e.g., 0.308 lb/MMbtu for Colstrip Unit 1, 2008–2010), as opposed to the anticipated post-combustion (i.e., with SOFA) rate of 0.20 lb/MMBtu assumed by EPA. This would lead to larger emission reductions being achieved by SNCR, and thereby, more favorable cost effectiveness.

Regardless, EPA did disclose the costs of SNCR alone (after SOFA) in our proposed rule. Consider for example our BART analysis for Colstrip Unit 1. See 77 FR 24025–24027 and spreadsheet entitled ''EPA SNCR Cost Colstrip Unit 1 Final'' located in the docket. The total annual cost of SNCR given in our proposed rule was $2,188,569, while the emission reductions were 664 tpy. This results in a cost effectiveness of $3,291/ton, essentially the incremental cost effectiveness between SNCR+SOFA and SOFA as given in Table 77 of the proposed rule. EPA selected SNCR as BART in consideration of these costs, all of which were presented to the public in our proposed rule.

Comment: Various commenters stated that EPA disregarded, or did not properly account for, issues associated with ammonia slip from SNCR systems. The commenters expressed concerns about both potential operational and environmental impacts. In regard to potential operational impacts, commenters expressed concerns about fouling of the air preheater. In regard to potential environmental impacts, commenters expressed concerns related to a visible wet plume, greenhouse gases, and toxic emissions.

Response: We disagree with these comments. In our proposed rule, we explicitly considered issues associated with ammonia slip from SNCR systems. For example:

> As Colstrip Unit 1 burns sub-bituminous PRB coal having a low sulfur content of 0.91 lb/MMBtu (equating to a SO_2 rate of 1.8 lb/MMBtu), [citation omitted] it was not necessary to make allowances in the cost calculations to account for equipment modifications or additional maintenance associated with fouling due to the formation of ammonium bisulfate. These are only concerns when the SO_2 rate is above 3 lb/MMBtu.[citation omitted] Moreover, ammonium bisulfate formation can be minimized by preventing excessive NH_3 slip. Optimization of the SNCR system can commonly limit NH_3 slip to levels less than the 5 parts per million (ppm) upstream of the pre-air heater.

77 FR 24025.

This observation has been verified by the vendor analyses submitted by PPL. For example, Fuel Tech stated that ''[s]ince the Colstrip 1&2 coal has low sulfur, there is less concern of ammonium bisulfate formation and its associated air preheater pluggage issues.'' [23]

We also find that concerns about the potential for adverse environmental impacts, such as a visible wet plume, toxic ammonia emissions, or greenhouse gas emissions, are unfounded or exaggerated. As previously discussed, optimization of the SNCR system would limit ammonia slip to acceptable levels (i.e., 5–10 ppm). Moreover, as noted in the BART determination for the Transalta Centralia Power Plant in Washington, ammonia in the gas stream is further removed when a wet scrubber is present.[24] Since the Colstrip Units 1 and 2 utilize wet scrubbers, no additional plume visibility or other local impacts would be anticipated.

While we did not quantify increases in greenhouse gases associated with SNCR in our proposed rule, we did quantify the additional amount of coal that is needed to account for the loss in thermal efficiency and found it to be insignificant. For example:

> SNCR reduces the thermal efficiency of a boiler as the reduction reaction uses thermal energy from the boiler.[citation omitted] Therefore, additional coal must be burned to make up for the decreases in power generation. Using CCM calculations we

[23] Fuel Tech, May 29, 2012.

[24] BART Determination Support Document for Transalta Centralia Generation LLC Power Plant, Centralia, Washington, Washington State Department of Ecology, revised November 2011, p. 13.

determined the additional coal needed for Unit 1 equates to 77,600 MMBtu/yr.

77 FR 24026.

We note that 77,600 MMBtu/yr is only 0.3% of the 2008–2010 annual average heat input for Colstrip Unit 1. The increase in CO_2 emissions would be proportional (that is, 0.3%). The formation of other greenhouse gases, such as nitrous oxide, would be highly dependent upon the reagent used, the amount of reagent injected and the injection temperature. Regardless, we note that the potential for CO_2 increases also exists for SCR, the technology favored by some commenters. This is due to the energy penalty associated with the large pressure drop across the SCR reactor. Therefore, consideration of greenhouse gases would not have necessarily favored SNCR over SCR.

Comment: MDEQ stated that EPA failed to provide analysis or consideration of the impact SNCR installation may have on mercury controls at Colstrip 1 & 2. MDEQ stated that this failure ignores factor 3 of the five-factor analysis, ''Any existing pollution control technology in use at the source.'' MDEQ contended that the application of SNCR will require these units to displace the sorbent injection systems which limit mercury emissions, and that this displacement will compromise the Montana Mercury Rule.

Response: We disagree with this comment. SNCR should have no impact on mercury capture in the scrubber or with mercury capture from sorbent injection and will neither improve nor harm any efforts at Colstrip Units 1 and 2 to comply with Montana's Mercury Rule. There is no reason why Colstrip Units 1 and 2 cannot utilize both SNCR and sorbent injection (if sorbent injection is what PPL chooses to use at Colstrip 1 and 2). Injection points for SNCR and for sorbent injection are at different locations—the furnace for SNCR and the downstream ductwork for sorbent injection. A review of EPA's National Electric Energy Data System (NEEDS) reveals that are currently 17 utility boilers equipped with both SNCR and activated carbon injection systems.[25] The list of facilities includes units ranging from 65 MW to 405 MW and burning both bituminous and subbituminous coals. Therefore, there is no basis for the assertion that these two pollution control systems cannot be used together on the same facility.

Comment: MDEQ stated that EPA lacks consideration of Montana's existing SIP requirements. For instance, sources required to add controls would have to provide ''de minimis'' notifications under ARM 17.8.745, or potentially a resource-intensive demonstration that the additional control would not contribute to a violation of an air quality standard. Additionally, MDEQ stated that some of the proposed controls might require either a minor source permit or a major modification under the NSR program. MDEQ expressed particular concern over EPA's lack of analysis of PPL's estimated increase in ammonia slip.[26] MDEQ suggested that increases in ammonia slip could lead to increases in $PM_{2.5}$ emissions at Colstrip 1 & 2, potentially requiring the unit(s) to submit a ''politically controversial, legally complex, and technically challenging'' NSR major modification permit. MDEQ also stated that an NSR major modification would significantly alter the time and cost required to implement the proposed BART.

Response: We disagree with these comments. MDEQ has not provided any data or information to substantiate that our BART determinations would interfere with existing SIP requirements, including those for permitting. They have only speculated that these might be concerns. In addition, these concerns would not negate our obligation to prescribe BART controls. We have addressed concerns related to ammonia slip in a separate response to comments.

Comment: Commenters stated that EPA asserted, with no analysis, that the energy needs associated with installation SNCR or SCR on the Colstrip Unit 1 and 2 are minimal and neither the additional energy requirements nor the nonair quality environmental impacts associated with disposal of the ash waste or transportation of the chemical reagents or catalysts warranted eliminating either SCR or SNCR.

Response: We disagree with this comment. We provided analysis of the energy impacts associated with SNCR and SCR in our proposed rule. For example, for the application of SNCR to Colstrip Unit 1 we ''determined the additional coal needed for Unit 1 equates to 77,600 MMBtu/yr.'' 77 FR 24026. Similarly, we determined that SCR requires ''additional electric power to meet fan requirements equivalent to approximately 0.3% of the plant's electric output.'' [citation omitted] 77 FR 24026. We also provided analysis of the non- air-quality impacts associated with SNCR and SCR in our proposed rule. See for example 77 FR 24026. We did not find it necessary to quantify these impacts as they are negligible. Also, the nonair quality impacts would be no different than those at numerous other boilers where SNCR or SCR have been successfully applied. Regardless, the commenters did not present any data or information that establishes that the energy or nonair quality impacts of SNCR or SCR would make these control options unacceptable.

Comment: NPS stated that allowing five years from promulgation of the rule to install SNCR on Colstrip Units 1 and 2 is excessive since it can be installed in less than one year.

Response: We agree that SNCR in some cases can be installed in less than one year. However, the BART Guidelines require compliance with the BART emission limit as expeditiously as possible but in no event later than five years after promulgation of the FIP. 40 CFR 51.308(e)(1)(iv). Our FIP is consistent with that requirement.

Comment: The NPS agreed with EPA that an annual emission rate of 0.05 lb/MMBtu is achievable with SCR.

Response: Comment noted.

Comment: EarthJustice stated that EPA incorrectly rejected SCR as BART for NO_X pollutant control for Colstrip Units 1 and 2. They asserted that EPA's analysis was biased against the selection of SCR as BART. They also asserted that we manipulated data, made assumptions, and performed calculations where the results are specified but the calculation itself is absent from the public record.

Response: We disagree with these comments. Our selection of SNCR+SOFA, and not SCR+SOFA, as BART was based on our objective consideration of the five statutory factors. Moreover, all of our analyses and assumptions were supported by the docket which was available for public review.

Comment: EarthJustice stated EPA underestimated the NO_X reductions that can be achieved with SCR technology. They stated that major SCR catalyst vendors routinely guarantee at least 90% removal efficiency for SCR systems.

Response: We disagree. EarthJustice has incorrectly assumed that a 90% control efficiency can be achieved in all applications regardless of the input NO_X emission rate or other parameters. The baseline annual emission rate for Colstrip BART units is around 0.31 lb/MMBtu (annually). After the installation of SOFA, the emission rate is expected to be 0.20 lb/MMBtu (annually). Therefore, a 90% control efficiency for SCR would correspond to a controlled emission rate of 0.02 lb/MMBtu

[25] Memo from Jim Staudt, Andover Technology Partners, to Doug Grano, July 13, 2012, p. 9.

[26] September 23, 2011 PPL submittal titled ''NO_X Control Update to PPL Montana's Colstrip Generating Station BART Report.''

(annually). We find that this is an unrealistic expectation of the level of control that can be achieved with SCR.

Comment: EarthJustice stated that EPA incorrectly used the Integrated Planning Model (IPM) for the direct capital costs of SCR for Colstrip Units 1 and 2 and that we failed to explain why we did so. They stated that the BART Guidelines require that the CCM be used for BART cost analyses, except for the site-specific cost of the equipment itself which will vary depending on site-specific conditions. EarthJustice also stated that our use of IPM led to the double counting of installation costs.

Response: We disagree with these comments. We explained our rationale for using IPM for direct costs for SCR in the proposed rule:

We relied on a number of resources to assess the cost of compliance for the control technologies under consideration. In accordance with the BART Guidelines (70 FR 39166 (July 6, 2005)), and in order to maintain and improve consistency, in all cases we sought to align our cost methodologies with the EPA's Control Cost Manual (CCM).[citation omitted] However, to ensure that our methods also reflect the most recent cost levels seen in the marketplace, we also relied on control costs developed for the Integrated Planning Model (IPM) version 4.10.[citation omitted] These IPM control costs are based on databases of actual control project costs and account for project specifics such as coal type, boiler type, and reduction efficiency. The IPM control costs reflect the recent increase in costs in the five years proceeding 2009 that is largely attributed to international competition. Finally, our costs were also informed by cost analyses submitted by the sources, including in some cases vendor data.

77 FR 24024.

As noted in the proposed rule, our use of IPM was intended to ensure that the direct capital costs reflect the most recent cost levels seen in the marketplace. Therefore, we disagree that this led to an overestimation of the costs of SCR. Also as noted in the proposal, while we did use IPM for direct capital costs, the remainder of our analysis for SCR conformed to the CCM.

EarthJustice is mistaken in asserting that our use of IPM led to the double counting of installation costs. EarthJustice is also mistaken in asserting that ''in the Cost Control Manual, those installation costs [direct installation costs] are included as indirect capital costs.'' Direct installation costs are treated in the same way whether using the CCM or IPM. That is, both provide direct capital costs that are inclusive of the direct installation costs. For example, the CCM states:

Direct capital costs (DCC) include purchased equipment costs (PEC) such as SCR system equipment, instrumentation, sales tax and freight. This includes costs associated with field measurements, numerical modeling and system design. *It also includes direct installation* costs such as auxiliary equipment (e.g., ductwork, fans, compressor), foundations and supports, handling and erection, electrical, piping, insulation, painting, and asbestos removal.[27] (emphasis added)

Similarly, the IPM documentation states the bare module costs include equipment, installation, buildings, foundations, electrical, and the retrofit factor.[28] Since we used the bare module capital costs to replace the direct capital costs in the CCM calculations, we did not double count direct installation costs. For example, for Colstrip Unit 1 we used the bare module capital cost of $55,578,137 (2010 dollars) as input for the direct capital cost.

Comment: EarthJustice stated that EPA overestimated capital costs of SCR on Colstrip Units 1 and 2 by using an inflated capital recovery factor (CRF) that is not based on accurate, available, site-specific information and by underestimating the lifetime of SCR. EarthJustice asserted that EPA should have used a CRF based on a 5% interest rate and an equipment life of 30 years

Response: We disagree that the CRF used by EPA led to an overestimation of capital costs for SCR. In our cost analysis for Colstrip Units 1 and 2, we used an interest (discount) rate of 7% for all control options. This is consistent with guidance contained in the Office of Management and Budget, Circular A–4, for regulatory analysis.[29] In regard to the equipment life assumed by EPA for SCR, the BART Guidelines state:

For example, the methods for calculating annualized costs in EPA's OAQPS Control Cost Manual *require the use of a specified time period* for amortization that varies based upon the type of control. If the remaining useful life will clearly exceed this time period, the remaining useful life has essentially no effect on control costs and on the BART determination process. Where the remaining useful life is less than the time period for amortizing costs, you should use this shorter time period in your cost calculations.

70 FR 39169 (emphasis added).

And in regard to SCR, the CCM states:

Capital recovery cost is based on the anticipated equipment lifetime and the annual interest rate employed. *An economic lifetime of 20 years is assumed for the SCR system.* The remaining life of the boiler may also be a determining factor for the system lifetime.[30] (emphasis added)

The equipment life assumed by EPA is consistent with that specified by the CCM for SCR (that is, 20 years). In addition, the consistent use of a 7% interest rate and 20 year equipment life ensures that the costs are comparable between all of the control options considered (provided that each option has an equipment life of at least 20 years). It also ensures that the costs are comparable to other BART analyses where similar assumptions have been made. However, we acknowledge that there may be circumstances where it is reasonable to assume a shorter or longer equipment life. In particular, it may be appropriate to consider a shorter equipment life where the owner plans to shut a unit down in less than 20 years.

Further, assuming a 30 year economic life would not change our conclusions regarding BART for Colstrip Units 1 and 2. For example, for Colstrip Unit 1 we have recalculated the cost-effectiveness amortizing over 30 years. The resulting cost effectiveness for SCR+SOFA is $2,879/ton, as compared to the cost effectiveness of $3,195/ton amortizing over 20 years which we cited in our proposed rule. We find that the cost of SOFA+SCR is reasonable regardless of the assumed equipment life. However, we find that the limited visibility benefits would continue to preclude our selection of SCR+SOFA as BART.

Comment: EarthJustice claimed that EPA skewed the cost effectiveness results away from SCR for Colstrip Units 1 and 2 by overestimating the operations and maintenance costs associated with SCR by approximately $600,000. In particular, EarthJustice questioned our costs for maintenance, catalyst replacement, and reagent use.

Response: We disagree. While EarthJustice has suggested alternate assumptions that could be made when estimating each of the operation and maintenance costs (that is, direct annual costs) noted, they have not substantiated that their assumptions are superior to those used by EPA. Moreover, they have not substantiated that EPA erred in making any of the cost assumptions related to operations and maintenance. They have only pointed out instances in which they would make different assumptions. Therefore, we see no reason that our cost assumptions for O&M should be supplanted by those that EarthJustice would otherwise choose in order to arrive at lower cost effectiveness.

Regardless, if we were to incorporate each of the changes to the O&M costs

[27] CCM, Section 4, Chapter 2, p. 2–41.

[28] IPM, Chapter 5, Appendix 5–2A, p. 2.

[29] Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

[30] CCM, Section 4, Chapter 2, p. 2–48.

suggested by EarthJustice, it would not change our BART determination. For example, for Colstrip Unit 1, reducing the O&M costs of SCR by $600,000 would only moderately lower the cost effectiveness of SNR+SOFA from $3,195/ton to $3,019/ton. Though we find that both of these costs are reasonable, we continue to find that there is insufficient visibility benefit (0.404 deciview for Unit 1 and 0.423 deciview for Unit 2 at the most improved Class I area) to support the selection of SCR as BART.

Comment: EarthJustice stated that EPA made multiple errors in our SCR cost analysis for Colstrip Units 1 and 2. EarthJustice claims that EPA made errors in relation to the baseline NO_X emissions, the control efficiency of SCR, the cost estimation method for direct capital costs (*CCM* vs. *IPM*), specific operation and maintenance costs, and the calculation of indirect annual costs (by way of the CRF). EarthJustice provided their own cost estimates for SCR, addressing the errors which they claimed EPA made. EarthJustice's cost effectiveness is 55–65% lower than the values calculated by EPA, making SCR+SOFA significantly more cost effective.

Response: We disagree that we made multiple errors in our SCR cost analysis for SCR for Colstrip Units 1 and 2 which led to inaccurate cost effectiveness. Each of the errors which EarthJustice claims EPA made has been addressed in separate responses. Therefore, we find that the cost effectiveness for SCR in the proposed rule was accurate and a correct basis for rejecting SCR as BART (in consideration of the remaining statutory BART factors).

Comment: The NPS commented that EPA has placed undue weight on the incremental cost effectiveness of SOFA+SCR at Colstrip Units 1 and 2.

Response: We disagree. In our proposed rule, we estimated the incremental cost effectiveness of SCR+SOFA (over SNCR+SOFA) to $5,770/ton and $5,887/ton, respectively. These costs far exceed the corresponding average cost effectiveness of $3,195/ton and $3,235/ton. Given these costs, we continue to find that SCR+SOFA is not justified by the visibility improvement that would be provided.

Comment: Some commenters stated that EPA properly concluded that SCR does not constitute BART for Colstrip Units 1 and 2, but that EPA incorrectly analyzed the capital costs and cost-effectiveness of SCR. Commenters stated that EPA failed to consider SCR costs estimates which PPL submitted in February 2012.[31] Commenters also stated that EPA's reliance on outdated information is not consistent with its own guidance to use engineering estimates and that EPA should modify its rationale in the final rule to conclude that, when the actual costs of the technology are taken into consideration, SCR is not a cost-effective technology. In particular, commenters noted that EPA estimates the capital cost of the SCR at $78 million and rejects PPL's cost estimate of $190 million

Response: We disagree that we incorrectly analyzed the capital costs and cost-effectiveness of SCR. We did not accept the SCR cost estimates submitted by PPL in February 2012 that were based on cost estimates provided to PPL by a consultant. EPA rejected these cost estimates for a number of reasons.

First, the cost estimates provided to PPL by the consultant do not represent site-specific costs. The BART Guidelines state that ''[t]he basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor (*i.e.,* budget estimates or bids) or by a referenced source (such as the OAQPS CCM Fifth Edition, February 1996, EPA 453/B–96–001).'' 70 FR 39166. Since the costs submitted by PPL were simply adapted from another (undisclosed) utility boiler, and are not specific to Colstrip Units 1 and 2, they should not be considered a budgetary bid as described in the BART Guidelines. In fact, PPL's consultant represents the costs as a ''feasibility capital cost estimate'' and not as a budgetary bid.[32]

Second, the capital costs for SCR claimed in PPL's February 2012 submittal are far in excess of the range of capital costs documented by various studies for actual installations. Five industry studies conducted between 2002 and 2007 have reported the installed unit capital cost of SCRs, or the costs actually incurred by owners, to range from $79/kW to $316/kW (2010 dollars).[33] These studies show actual capital costs are much lower than estimated by PPL for Colstrip Units 1 and 2 ($571/kW for each unit; 2011 dollars). Moreover, the capital costs surveyed by the studies represent a range of retrofit difficulties, including very difficult retrofits having significantly impeded construction access, extensive relocations, and difficult ductwork transitions. Therefore, to the extent that similar retrofit difficulties may exist for Colstrip Units 1 and 2, the high end of the range documented in the reports is representative.

Third, we are concerned about the disparity among the various cost estimates submitted by PPL. Between August 2007 and February 2012, PPL submitted four separate SCR cost estimates for the Colstrip Unit 1 and 2. In the first SCR cost estimate, submitted in August 2007, PPL estimated capital costs of $25,282,233 ($76/kW), total annual costs of $7,289,482 and a cost effectiveness of $2,272/ton (each unit; 2007 dollars).[34] In the second SCR cost estimate, submitted in June 2008, PPL estimated capital costs of $29,581,465 ($88/kW), total annual costs of $7,987,179 and a cost effectiveness of $1,735/ton (each unit; 2008 dollars).[35] PPL's first and second cost estimates were generally performed in conformance with EPA's CCM. The lower cost effectiveness in the second submittal was driven primarily by a change in the assumed maximum control level (from 0.15 lb/MMBtu to 0.06 lb/MMbtu), and thereby greater annual emission reductions. In the third SCR cost estimate, submitted in September 2011, PPL estimated capital costs of $152,508,328 ($457/kW), total annual costs of $16,733,719 and a cost effectiveness of $7.405/ton (each unit; 2011 dollars).[36] The third cost estimates were largely based on control costs developed for the Integrated Planning Model.[37] PPL assumed a retrofit factor of 2 when using the IPM approach. We note that this retrofit factor, equating to 100% over the IPM base model capital costs, was unsupported and far in excess of the range described in the IPM documentation: ''Retrofit difficulties associated with an SCR may result in capital cost increases of 30 to 50% over the base model.'' [38] In the fourth SCR cost estimate, submitted in February 2012, PPL estimated capital costs of $190,000,000 ($571/kW), total annual

[31] Letter from David Bowen, Burns & McDonnell, to James Parker, PPL Montana, February 7, 2012.

[32] Bowen letter.

[33] Dr. Phyllis Fox, Revised BART Cost-Effectiveness Analysis for Tail End Selective Catalytic Reduction at Basin Electric Power Cooperative Leland Olds Station Unit 2. Report Prepared for U.S. EPA, RTI Project Number 0209897.004.095, March 2011.

[34] BART Assessment Colstrip Generating Station, prepared for PPL Montana, LLC, by TRC (''Colstrip Initial Response''), August 2007, Table A4–8(c).

[35] Addendum to PPL Montana's Colstrip BART Report Prepared for PPL Montana, LLC; Prepared by TRC, (''Colstrip Addendum''), June 2008, Table 5.3–3.

[36] NO_X Control Update to PPL Montana's Colstrip Generating Station BART Report Prepared for PPL Montana, LLC, by TRC, September 2011, Table 2–3b.

[37] Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model, August 2010, EPA #430R10010.

[38] IPM, Chapter 5, Appendix 5–2A, p. 1.

costs $19,956,767, and a cost effectiveness of $8,884/ton (each unit; 2011 dollars).[39] The fourth cost estimate was also largely based on control costs taken from IPM, but was augmented by capital cost estimates provided to PPL by a consultant. In all, the capital costs varied by a factor of more than seven ($76/kW to 571/kW), and the cost effectiveness varied by a factor of more than 5 ($1,735/ton and $8,884/ton). The large disparity between PPL's February 2012 cost estimates and those in their previous submittals led us to question their accuracy.

Finally, PPL's February 2012 cost estimates contained cost items that are either speculative in nature or not well documented. For example, they include capital costs for duct and boiler reinforcement even though the potential for boiler implosion was not evaluated by PPL's consultant.[40]

For the reasons stated above, EPA finds that no changes to the BART determinations or to the FIP are needed in response to this comment.

Comment: Various commenters objected to EPA's BART determinations for Colstrip 1 and 2. EarthJustice urged EPA to require selective SCR+SOFA as the best system of continuous emission control to meet a 0.05 lb/MMBtu NO_X emission limit applicable on a 30-day rolling average basis. NPS also recommended that we require SCR+SOFA. PPL supported a BART emissions rate for NO_X of 0.20 lb/MMBtu on a 30-day rolling average basis, reflecting the installation of SOFA.

Response: Based on our consideration of the five statutory BART factors, we continue to find that BART for NO_X at each of the Colstrip Unit 1 and 2 is an emission limit of 0.15 lb/MMBtu (30-day rolling average) achievable with SNCR+SOFA.

Comment: PPL stated that EPA's proposed emission limit for PM of 0.10 lb/MMbtu on a 30-day rolling average for each of the Colstrip Unit 1 and 2 is flawed. PPL asserted that the current PM limit is 0.10 lbs/MMBtu as an annual average, based on a compliance assurance monitoring plan together with annual stack testing. In order to accommodate the shorter averaging period, the PPL suggested that the 30-day rolling average emission limit proposed in the FIP be increased to 0.12 lb/MMBtu.

Response: We disagree with some aspects of this comment, but agree with others. PPL has erred in stating that the current PM limit is 0.10 lb/MMBtu as an annual average. The Final Title V Operating Permit (#OP0513–06) indicates that the emission limit is 0.10 lb/MMbtu, but does not provide an averaging period. The Title V permit requires that compliance with the emission limit be demonstrated by a Method 5 or Method 5B stack test once per year. As these stack test methods typically consist of three sampling runs of at least 120 minutes in duration, and are not long-term continuous measurements, it is not possible to average the emissions over 30-days or a year. For this reason, we corrected the proposed PM emission limits in a correction notice. 77 FR 29270. We clarified that that emission limits for NO_X and SO_2, but not PM, shall apply on a 30-day rolling average.

As we are not requiring that PM emission limits apply on a 30-day rolling average, PPL's suggestion that the emission limit be increased to 0.12 lb/MMBtu is no longer relevant. The PM emission limits will remain unchanged from those in the proposed rule which are identical to those in the Title V permit.

Comment: EarthJustice stated that EPA's exemption of Colstrip Units 1 and 2 from BART for PM is improper and unsupported. EarthJustice asserts that EPA has not complied with its statutory and regulatory obligations to determine BART for PM emissions from Colstrip Units 1 and 2 in that EPA simply made a declaration and skipped the statutory process. EarthJustice stated that the existing venturi scrubbers are not best technology and have not been considered such for a long time because particle scrubbers do not remove particulates sufficient to comply with basic CAA requirements. In addition, EarthJustice stated that EPA should have considered more effective technologies, such as baghouses.

Response: We disagree. As with existing SO_2 controls, we do not find that it is necessary to consider the replacement of existing PM controls with new controls. This is particularly true for PM as the existing controls for Colstrip Units 1 and 2 currently reduce emissions by more than 98%. Moreover, the contribution to the baseline visibility impact from PM is very small (e.g., for Colstrip Unit 1, less than 4% of 0.922 deciview, or 0.037 deciview). The most visibility improvement that could be expected, even if all PM were eliminated, is 0.037 deciview. The visibility improvement that could be expected with upgrades to the existing PM controls is only a fraction of 0.037 deciview. Therefore, it was reasonable for us to conclude that the existing controls represent BART.

In addition, EarthJustice has conflated the most stringent controls with BART. BART is not necessarily the most stringent controls, but the best system of continuous emission reduction taking into consideration the five statutory factors.

Comment: NPS stated that they disagree with the PM emissions that we used in modeling the visibility impacts for Colstrip Units 1 and 2. They stated that the PM emissions data provided by PPL is more representative because it included both condensable and filterable PM emissions, while the PM data used by EPA did not measure condensable PM.

Response: The difference in the approach used to characterize PM emissions for visibility modeling purposes is negligible. Moreover, as the PM emissions were held constant for all of the control scenarios that EPA modeled, they had no impact on our BART determinations for NO_X and SO_2.

Comment: EarthJustice stated that EPA made the same error in calculating baseline emissions in its SO_2 BART determination for Colstrip Units 1 and 2 as it did in its NO_X BART determination. EarthJustice asserted that EPA should have used a baseline of 2001–2003.

Response: We disagree with this comment. As discussed in a separate response to comments, we have established a baseline which provides a realistic depiction of anticipated annual emissions for the source. For example, the 2008–2010 baseline we used for Colstrip Unit 1 reflects annual average emissions of 5,548 tons/yr. By comparison the annual average emissions for 2000–2010, 5,504 tons/yr, were only slightly lower.

Comment: PPL stated that EPA's estimate of the performance that can be achieved with lime addition on Colstrip Units 1 and 2 was wrong. The commenter stated that EPA's assumed emission rate for SO_2 of 0.15 lbs/MMBtu was overly optimistic, and that a rate of 0.20 lbs/MMBtu on a 30-day rolling average basis is achievable.

Response: We disagree with this comment. The emission rate which EPA assumed for limestone lime addition (injection) on Colstrip Units 1 and 2 was 0.15 lb/MMBtu on an annual basis, not on a 30-day rolling average basis. This was based on PPL's amended BART submittal of August of June 2008.[41] We did not specify a 30-day rolling average

[39] Letter from Mark M. Hultman, P.E., TRC, February 9, 2012.

[40] Bowen letter, p. 2.

[41] Colstrip Addendum, p. 4–1.

emission limit for limestone injection since we did not select it as BART.

Comment: PPL commented that installation of an additional scrubber vessel is technically impracticable, if not infeasible, due to space constraints and the potential for equipment scaling.

Response: First, addition of a fourth scrubber vessel for each of Colstrip units 1 and 2 does not appear to be impracticable due to space constraints. PPL's argument that there is no space availability for an additional scrubber vessel is not supported by its own consultant. In addition, the site visit conducted by EPA [42] verified and the site plan provided by PPL shows ample space for locating additional equipment. A satellite image of units 1 and 2 located in the docket.[43] In fact, PPL's consultant, Burns & McDonnell was able to find space for a new vessel with associated ductwork: ''[t]here is sufficient space behind the stacks for installation of the fourth scrubber module, ID fan, ductwork and accessories.'' [44] As URS pointed out, this might require an additional booster fan, which is included in the Burns & McDonnell estimate.[45]

Second, an additional scrubber vessel may not be necessary to avoid scaling. It is possible to inject lime and mitigate the risk of scaling through addition of a forced oxidation system or by use of chemical additives that mitigate scaling. The current system uses natural oxidation. Forced oxidation will enable higher lime injection rates while avoiding scaling. Forced oxidation systems will require blowers and piping, and agitators that could be retrofit on the existing scrubber vessels at what is likely to be a much lower cost than the cost of a new absorber vessel. An alternative to forced oxidation is use of chemical additives that address scaling. These additives are available from companies such as Nalco Chemical Company.

We find that it is acceptable for PPL to reduce emissions by means other than installing an additional scrubber vessel, provided that the emission limit of 0.08 lb/MMBtu on a 30-day rolling average is met.

Comment: PPL stated that EPA overstated the emissions benefit of an additional scrubber vessel.

Response: PPL argues that an additional vessel would not in fact reduce emissions because velocity through the existing scrubber vessel tray will be reduced. As noted in responses to other comments, an additional scrubber vessel may not be necessary to achieve 95% SO_2 capture. Nevertheless, with regard to addition of another scrubber vessel and the impact on SO_2 reduction, PPL relies on a June 15, 2012, letter from Jonas Klingspor of URS Corporation that states the reduced gas velocity would reduce SO_2 reduction. The URS letter and PPL, however, overlook the fact that the openings in the tray for the existing vessels could be reduced to restore gas velocity to the original level.

URS provided estimates of emission rates possible under different conditions. The analyses performed by URS were limited either by increased scaling (the lowest rate of 0.13 lb/MMBtu with three vessels) or lower absorber gas velocity (0.16 lb/MMBtu with four vessels). Since URS did not evaluate addition of a forced oxidation system or any other means to address scaling, it is likely that a significantly lower emission rate than 0.13 lb/MMBtu is possible while using three vessels. And, addition of a fourth scrubber vessel, with tray openings in the three original vessels adjusted to maintain gas velocity, in combination with a forced oxidation system would certainly increase SO_2 capture performance even more.

Regardless, if PPL uses the additional scrubber vessel as a spare in a manner similar to that for Colstrip Units 3 and 4, then gas flow will remain unchanged. In this mode of operation, the spare scrubber vessel helps allow for maintenance that is needed due to the scaling caused by the additional lime. Without the spare vessel, the unit must be shut down to perform the maintenance. This is the mode of operation proposed by PPL in their August 2007 submittal.

Comment: Commenters stated that an additional scrubber vessel costs far more than EPA proposed and is therefore not cost-effective. Commenters stated that it was inappropriate for EPA to rely on outdated costs for an additional scrubber vessel in our proposed rule. PPL provided cost estimates obtained from Burns & McDonnell [46] showing higher costs than estimated by EPA.

Response: Foremost, we note that the costs that we cited for an additional scrubber vessel in our proposed rule were costs provided by PPL in their BART submittals of August 2007 and June 2008. PPL did not explain why the cost estimates submitted by PPL during the comment period are more than two and a half times their original cost estimates.

The cost estimated by Burns & McDonnell of adding a single module to treat 25% of the flue gas is unreasonable, equating to around $213/kW ($71 million divided by 333,000 kW),– or the equivalent of $853/kW when adjusting for the fact that only one fourth of the flue gas is being treated. To put this in perspective, this is more costly on a $/kW basis than the typical cost of a complete limestone forced oxidation wet FGD system (around $500/kW) that would provide over 95% removal for 100% of the flue gas.[47] Also, according to the 2010 EIA Form 860 Enviroequip data, the original scrubber structure with three modules for Colstrip Unit 1 cost $34 million in 1975 (slightly over $100/kW). Using the Chemical Engineering Plant Cost Index (CEPCI) to escalate to 2011 dollars, the cost in today's dollars would be about $109 million ($34 million times 585.7/182.4, or about $327/kW). This would suggest the cost of an additional vessel to be on the order of $27 million, or about 38% of what Burns & McDonnell estimated and consistent with what EPA has previously estimated. Moreover, the difference in cost between EPA's estimate and what Burns & McDonnell has estimated is far too large to be explained by the additional ductwork and fans associated with the retrofit, which PPL asserts are necessary. Additionally, Table 4–1 of the documentation from Burns & McDonnell has several costs that are questionable or high ($900,000 for Owner's Project Management and $400,000 for Owner's Legal Counsel and $3.4 million in Escalation) and others that are very high and therefore require better explanation ($8.1 million for furnish and erect packages plus the estimates for Mechanical, Electrical and Civil and Structural Construction that total over $12 million). Engineering costs as well as many other costs are typically determined as a percentage of the other costs, therefore the effect of overestimation of one cost is compounded because it contributes to overestimation of other costs. Because the estimate by Burns & McDonnell is so much higher than what is reasonably expected and includes several unsubstantiated and questionable cost elements. In any event, an additional scrubber vessel may not be necessary if a forced oxidation system or other means to control scaling is used on the existing three scrubber vessels. PPL may determine that other means may be

[42] On September 27, 2011 Aaron Worstell and Vanessa Hinkle conducted a site visit at Colstrip.

[43] Staudt memo, p. 4.

[44] Report on the Fourth Scrubber Module Cost Estimate for PPL, Burns and McDonnell, p. 4–3.

[45] Letter from Jonas Klingspor, URS Corporation, to Gordon Criswell, PPL Montana, June 15, 2012.

[46] Burns and McDonnell, p. 1–1.

[47] IPM, Chapter 5, Table 5–4 shows a range of illustrative $/kW costs.

better than adding an additional scrubber vessel in terms of cost or other factors for achieving the BART emission rate.

Comment: Commenters stated that EPA did not properly consider the incremental cost-effectiveness of additional scrubber vessels at Colstrip Units 1 and 2. Commenters stated that while the average cost-effectiveness of lime injection and an additional scrubber vessel is $912/ton, the incremental cost-effectiveness of a scrubber vessel is $2,379/ton, nearly three times higher.

Commenters also stated that it was improper for EPA to evaluate lime injection and an additional scrubber vessel together. Commenters stated that the incremental cost of adding an additional scrubber vessel to lime injection outweighs the benefits. In particular, they noted that use of lime injection alone would cost $1,883,200, while the addition of a scrubber vessel adds $2,217,000 to the total cost. By contrast, they noted that the SO_2 reductions achieved from the addition of the scrubber vessel are 929 tpy, while the use of lime injection alone results in emission reductions of 3,557 tpy.

Response: We agree with this comment in part. We miscalculated the incremental cost effectiveness of an additional scrubber vessel at Colstrip Unit 1 (which we stated to be $1,975/ton), but not at Colstrip Unit 2 ($2,410/ton). The correct incremental cost effectiveness for an additional scrubber vessel at Colstrip Unit 1 is $2,380/ton, not $1,975/ton as given in our proposed rule.

However, we disagree that it was improper to evaluate lime injection with an additional scrubber vessel together. We also disagree that cost of the additional scrubber vessel outweighs the benefits. For example, for Colstrip Unit 2, individually the total annual cost of an additional scrubber vessel is $2,210,000, while the emission reduction is 917 tons per year. This results in a cost effectiveness of $2,410, essentially the same as the incremental cost effectiveness between the two control options. The visibility improvement from lime injection alone is 0.225 deciview (at Theodore Roosevelt NP), while the improvement from lime injection with an additional scrubber vessel is 0.280 deciview (at Theodore Roosevelt NP). We continue to find that the cost is reasonable given the visibility benefits and that lime injection with an additional scrubber vessel represents BART.

Comment: PPL commented that in proposing SNCR, EPA appears to rely on its determination that relevant Class I areas are currently above the Regional Haze Glide Path (RHGP). 77 FR 24,038. The RHGP is an important factor for the reasonable progress goals, but it is not one of the five statutory factors specified for EPA to consider in its BART analysis. Furthermore, as discussed above, there is no incremental benefit in visibility from installation of SNCR that would affect the area improvement in visibility relative to the glide path.

Response: We agree with some aspects of this comment and disagree with others. We agree that the Regional Haze glidepath is not one of the five statutory factors specified for EPA to consider in its BART analysis. We based our decision solely on the five statutory factors.

Comment: EarthJustice stated that EPA settled for minor adjustments for SO_2 pollutants from Colstrip Units 1 and 2 instead of proper BART controls. In particular, EarthJustice stated that EPA failed to examine a full suite of options for SO_2 BART, including replacement of the existing scrubbers with state-of-the-art scrubbers that could remove 98% of the SO_2 from Colstrip Units 1 and 2.

In addition, EarthJustice claimed that EPA failed to consider all feasible upgrades to the existing venturi scrubbers, including the use of magnesium enhanced lime. EarthJustice stated that significant emission reductions could be achieved via these upgrades, even without the installation of an additional scrubber vessel. EarthJustice held that an emission limit of 0.06 lb/MMbtu can be achieved with these upgrades.

Response: We disagree that we should have considered replacement of the existing controls. As noted in our proposed rule, for example:

> The Colstrip Unit 1 venturi scrubber currently achieves greater than 50% removal of SO_2. For units with preexisting post-combustion SO_2 controls achieving removal efficiencies of at least 50%, the BART Guidelines state that upgrades to the system designed to improve the system's overall removal efficiency should be considered.

77 FR 24028.

The BART Guidelines only recommend evaluating constructing a new FGD system ''[f]or coal-fired EGUs with existing post-combustion SO_2 controls achieving less than 50 percent removal efficiencies.'' 70 FR 39171. Therefore, it was appropriate for us to not consider new state-of-the art scrubbers, or for that matter, any replacement technology.

As noted in a separate response, we agree that it may not be necessary to add an additional scrubber vessel in order to achieve an emission limit of 0.08 lb/MMBtu on a 30-day rolling average. We acknowledge that it may be possible to achieve the emission limit with modifications to the existing scrubbers, such as a forced oxidation system or by use of chemical additives that mitigate scaling. However, these alternative approaches would likely be at a lower cost than an additional scrubber vessel. Given that equivalent emission reductions would be achieved at lower costs, the cost effectiveness would be even more reasonable. Accordingly, we are extending flexibility to PPL to meet the emission limit using the lowest cost approach.

Regardless of whether PPL chooses to meet the emission limit with an additional scrubber vessel or modifications to the existing scrubber vessels, we continue to find that an emission limit of 0.08 lb/MMBtu, and not 0.06 lb/MMBtu as suggested by the commenter, is appropriate. As noted in the proposed rule, this is based on the level of performance being achieved by Colstrip Units 3 and 4 which already employ scrubbing systems similar to that being contemplated for Colstrip Units 1 and 2.

The use of MEL is addressed in a separate response to a similar comment from EarthJustice in regard to Colstrip Units 3 and 4.

H. Comments on Corette

Comment: EarthJustice indicated that EPA's decision not to impose BART on Corette violates the statutory requirements for BART and is not supported by the facts. EarthJustice stated that EPA engaged in the same kind of non-BART result oriented process for Corette as it did for Colstrip. They asserted that EPA's approach is no more legitimate or compliant with the haze requirements in the case of Corette. Based on their own BART analyses, they determined that BART for Corette is installation of a dry scrubber and baghouse for the control of SO_2 and PM emissions, and SCR+SOFA for NO_X.

Response: We disagree with this comment. Our selection of BART for Corette was based on our objective consideration of the five statutory factors. We continue to find no additional controls are necessary for Corette. Below, we address specific issues raised by EarthJustice in regard to our BART determination for Corette.

Comment: EarthJustice stated that, as with Colstrip Units 1 and 2, we used an improper baseline in our BART evaluation of 2008–2010. EarthJustice asserted that using these years artificially depresses the emissions baselines, which in turn makes visibility improvement appear less than they actually are and thereby makes BART alternatives look less cost-effective than they actually are.

Response: See response to similar comments made by EarthJustice in regard to Colstrip Units 1 and 2. Here again, as required by the BART Guidelines, we used a baseline that is reflective of actual operations. We acknowledge that the 2008–2010 emissions for both SO_2 and NO_X were in fact somewhat lower than the long-term trend. For example, the 2000–2010 SO_2 emissions were 3,129 tpy, while the 2008–2010 emissions were 2,723 tpy. Similarly, the 2000–2010 NO_X emissions were 1,748 tpy, while the 2008–2010 emissions were 1,625 tpy. Nonetheless, the difference in the baseline emissions would not have impacted the cost-effectiveness calculations in an appreciable manner.

Comment: EarthJustice stated that EPA understated the cost effectiveness of SCR+SOFA.

Response: See response to similar comment made by EarthJustice in regard to Colstrip Units 1 and 2.

Comment: EarthJustice stated that EPA's cost-effectiveness calculations for SO_2 controls for Corette contain a number of incorrect assumptions. In particular, EarthJustice stated that much lower emission reductions can be achieved with LSD (90% with low sulfur coal) than assumed by EPA. Also, EarthJustice stated that EPA's approach of using IPM for capital costs resulted in a double counting of installation costs.

Response: We disagree. See response to similar comment made by EarthJustice in regard to Colstrip Units 1 and 2.

As we have noted previously, EarthJustice has erred in assuming that a given control efficiency can be achieved in all applications regardless of the input emission rate or other parameters. The level of performance assumed by EPA for LSD (0.065 lb/MMBtu annually) is generally reflective of what can be achieved with this technology.

Further, we used IPM based calculations for both capital costs and O&M costs for SO_2 controls at Corette. (This is unlike for NO_X controls, where we used IPM based capital costs to reflect recent market trends). Therefore, we could not have double counted the installation costs for SO_2 controls (from IPM and the CCM).

Comment: EarthJustice stated that EPA wrongly exempted Corette from BART for PM.

Response: See response to a similar comment made by EarthJustice in regard to PM BART for Colstrip Units 1 and 2.

Comment: PPL stated that they support our conclusions with respect to BART for Corette that further controls are not justified.

Response: Comment noted. The final FIP does not require additional controls for Corette.

Comment: Commenters stated that they disagree with EPA's cost analysis for NO_X and SO_2 control technologies at Corette and that EPA incorrectly concluded that a number of the control technologies are cost-effective. Commenters noted that PPL submitted a five factor BART analysis for Corette in August 2007, and later supplemented with the analysis with updated information in June 2008 and September 2011.[48] Commenters stated that in view of the information that PPL provided, EPA incorrectly concluded that SOFA, SOFA+SNCR, and SOFA+SCR are ''all cost effective technologies'' (77 FR 24043) and that the proposed FIP also incorrectly concluded that dry sorbent injection (DSI) for SO_2 is cost-effective at $3,940/ton. 77 FR 24047.

Commenters stated that as documented in PPL's 2011 submissions, the company used the IPM control technology cost estimation techniques, which are more robust than those used in previous BART reports submitted by PPL.[49] Commenters stated that with respect to NO_X, PPL determined the cost-effectiveness of SNCR to be approximately $13,544/ton (as compared to EPA's $2,596 for SOFA+SNCR) and the cost-effectiveness for SCR to be $8,457/ton of additional NO_X controlled (as compared to EPA's $4,491 for SOFA + SCR).[50] The company stated that for SO_2 controls, the updated analysis determined that the cost-effectiveness of DSI is $10,920/ton (as compared to EPA's $3,940/ton).[51] Commenters stated that the proposed FIP failed to consider that the installation of DSI would most likely require upgrades to the existing particulate controls to achieve the SO_2 reductions that EPA evaluated and that EPA relied on the outdated and inaccurate CCM to develop these estimates.

Response: We disagree. See our response to similar comments made by PPL in regard to cost analyses for Colstrip Units 1 and 2. PPL's cost estimates for Corette included many of the same incorrect methods and assumptions that the company used when developing cost estimates for Colstrip Units 1 and 2. In particular, PPL used unsupported retrofit factors that were well in excess of the range described in the IPM documentation.

Also, we disagree that installation of DSI would most likely require upgrades to the existing particulate controls to achieve the SO_2 reductions that EPA evaluated. In fact, DSI using trona would ''typically either improve performance or have little impact, even at high injection rates.'' [52] It would not require the replacement of the existing ESP with a new baghouse as reflected in PPL's cost effectiveness estimate of $10,920/ton.[53] Therefore, we find that EPA's cost estimate of $3,490 is accurate.

Comment: Commenters stated that our proposed SO_2 and NO_X emission limits for Corette were flawed. One commenter stated that EPA must increase the limits to no less than 0.81 lb/MMBtu for SO_2 and 0.46 lb/MMBtu for NO_X in order to account for compliance over a 30-day rolling average. By contrast, another commenter stated that our proposed emission limits were too high and would actually result in increased emissions.

Response: Based on these comments, we have reassessed our SO_2 and NO_X emission limits for Corette. As we have not prescribed any additional controls for Corette, the emission limits should reflect emission rates currently being achieved with existing controls. In order to establish appropriate emission limits, we have conducted a statistical analysis of the monthly emissions data contained in the CAMD emissions system. For the period 2000–2010, the 99th percentile monthly SO_2 emission rate was 0.548 lb/MMbtu. Similarly, the 99th percentile monthly NO_X emission rate was 0.335 lb/MMBtu. In our final action, we are establishing emission limits slightly above these 99th percentile emission rates in order to allow a sufficient margin for compliance. This is because the emission limits must apply at all times,

[48] NO_X Control Update to PPL Montana's J.E. Corette Generating Station BART Report, September 2011, Prepared for PPL Montana, LLC by TRC, at ES–1 (''NO_X Control Update''); SO_2 Control Update to PPL Montana's J.E. Corette Generating Station BART Report, August 2011, Prepared for PPL Montana, LLC by TRC, at ES–1 (''SO_2 Control Update'')

[49] See NO_X Control Update to PPL Montana's J.E. Corette Generating Station BART Report, September 2011, Prepared for PPL Montana, LLC by TRC, at ES–1 (''NO_X Control Update''); SO_2 Control Update to PPL Montana's J.E. Corette Generating Station BART Report, August 2011, Prepared for PPL Montana, LLC by TRC, at ES–1 (''SO_2 Control Update'').

[50] NO_X Control Update, at ES–3.

[51] SO_2 Control Update, at 14.

[52] United Conveyer Corporation Dry Sorbent Injection FAQ (*http://unitedconveyor.com/dsi_systems/*).

[53] Ref 2: SO_2 Control Update to PPL Montana's J.E. Corette Generating Station BART Report, Prepared for PPL Montana, LLC, by TRC, August 2011, p. ES–2.

including during startup, shutdown, and malfunction. The revised emission rates are 0.57 lb/MMBtu for SO_2 and 0.35 lb/MMBtu for NO_X, both on a 30-day rolling average. We have revised the emission limits for Corette contained in section 52.1396(c)(1) accordingly. Our complete analysis of SO_2 and NO_X emission limits for Corette can be found in the docket.0.5480.3350.57 We have addressed the emission limit for PM at Corette in a separate response to comments.

Comment: PPL stated that EPA's PM emission limit for Corette was flawed. PPL noted that over the past five years, stack test results have shown that PM emissions have ranged from 0.059 lb/MMBtu to 0.252 lb/MMBtu. PPL stated that an emission limit of 0.30 lb/MMBtu would be necessary to account for a 30-day rolling average.

Response: We agree, in part. In our proposed rule, we incorrectly specified a PM emission limit of 0.10 lb/MMBtu on a 30-day rolling average. In consideration of the stack test data provided by PPL, we have determined that that a limit of 0.26 lb/MMBtu is more appropriate. In addition, and as discussed in response to a similar comment made by PPL in regard to Colstrip, we find that it is not feasible to require compliance with this emission limit on a 30-day rolling average. Again, this is because compliance is shown using stack methods such as Method 5 and 5B. These stack test methods typically consist of three sampling runs of at least 120 minutes in duration, and are not long-term continuous measurements. As such, it is not possible to average the emissions over 30 days or a year.

Accordingly, we are revising our FIP to reflect a PM emission limit for Corette of 0.26 lb/MMBtu. We are also removing the 30-day averaging period requirement for the PM emission limit at Corette. More specifically, we are revising section 52.1396(c)(1) to clarify that emission limits for NO_X and SO_2, but not PM, shall apply on a 30-day rolling average. Note that we are retaining the requirement that compliance with the PM emission limit shall be monitored in accordance with the CAM plan.

As we are not requiring that the PM emission limit applies on a 30-day rolling average, PPL's suggestion that the emission limit be increased to 0.30 lb/MMBtu is no longer relevant.

Comment: The USFWS commented that there are at least two other similarly-sized installations implementing lime spray drying (LSD) for SO_2 control that justify the positions taken by EPA in the proposed BART determination. USFWS stated that in justifying emission limits of small units burning clean coal, Newmont Nevada is a 200 MW plant that attains a 30-day rolling average 0.065 lb/MMBtu SO_2 emission limit with an SO_2 control efficiency of 93.1% and that capital cost of LSD units is corroborated by Great River Energy's 188 MW Stanton #1 plant costing $79,514,000.

Response: We acknowledge that the USFWS has provided information from two other similarly-sized installations which are implementing LSD for SO_2 corroborating our LSD cost estimates for Corette. However, as noted in our proposed rule, the cost of controls is not justified by the visibility improvement (0.253 deciview).

Comment: The USFWS stated that the capital costs proposed by EPA for dry sorbent injection (DSI) and LSD should be considered as maximums, because the costs should only decrease due to significant curtailment of construction of air pollution control devices during the economic downturn and cancellation or postponement of many coal burning electrical generation units. The USFWS stated that quantified estimates of the decreases could provide for firm reductions in the capital cost estimates, but it is agreed that they would be difficult to affirm with confidence at this time.

Response: We agree that any changes in cost associated with economic downturn would be difficult to affirm with confidence at this time.

Comment: The USFWS stated that the paragraph following Table 123 states that EPA considers $4,659 per ton of SO_2 emissions reduction using DSI as reasonable, but that $5,442 per ton for LSD is not cost effective. The USFWS stated that other proposed SO_2 BART determinations resulting in cost efficiency in the range of Corette include PacifiCorp's Dave Johnston, WY–$4,743; Northshore Mining's Silver Bay Power, MN–$7,309 and Xcel Energy's Taconite Harbor, MN–$5,300 and as stated above, the capital cost of an LSD unit on Great River Energy's 188 MW Stanton #1 plant is $79,514,000. USFWS stated that such a total capital cost incorporated as the cost of LSD at Corette would result in a cost per ton of SO_2 removed of $4,891 and that the LSD alternative might then also be considered by EPA as being cost effective along with DSI.

Response: We disagree. We continue to find that the cost of LSD for Corette is not justified by the visibility improvement. Moreover, the capital cost that we estimated for LSD is specific to Corette, and we see no reason to supplant that cost with costs from Taconite Harbor or other individual facilities.

Comment: The USFWS stated that regarding the cost-effectiveness of visibility improvement for SO_2 controls, the second paragraph after Table 123 in the draft proposed BART determination states, '' * * * the cost of controls is not justified by the visibility improvement'' and that this proposed conclusion warrants further scrutiny. The USFWS stated that implementation of the DSI alternative results in a 0.176 deciview improvement at Washakie WA, the highest impacted Class I area, at a cost of $3.4 million per deciview of improvement and that this is a very reasonable cost for visibility improvement. The UFWS stated that the cost of visibility improvement for SO_2 controls proposed in other BART determinations for a single most-impacted Class I area include: Colorado Springs Utilities, Martin Drake, CO–$49.9 million/deciview; PacifiCorp, Wyodak, WY–$44.7 million/deciview; PacifiCorp, Jim Bridger, WY–$37.1 million/deciview; PG&E, Boardman, OR–$35.2 million/deciview; and Dominion, Brayton Point, MA–$33.9 million/deciview; Northshore Mining, Silver Bay Power, MN–$26.2 million/deciview; Dominion, Salem Harbor, MA–$25.1 million/deciview; Great River Energy, Stanton #1, ND–$21.9 million/deciview; PacifiCorp, Naughton, WY–$18.2 million/deciview; PacifiCorp, Dave Johnson, WY–$16.7 million/deciview. The USFWS stated that the conclusion from the above is that since the cost per ton of SO_2 removal and the cost per deciview of visibility improvement are both reasonable, DSI should be considered as a feasible and cost-effective SO_2 control alternative and be accepted as BART for the PPL Montana, J.E. Corette Generating Station.

Response: We disagree. The total annual cost of DSI for Corette, as cited in our proposed rule was $5,363,896, while the greatest visibility improvement was 0.176 deciview (Washakie WA). This results in cost of $30 million per deciview, not $3.4 million per deciview. We continue to find that the cost of LSD for Corette is not justified by the visibility improvement.

Comment: The USFWS commented that Table 110 states the visibility improvement associated with each of the three NO_X control alternatives and by dividing respective Total Annual Costs by their visibility improvements, they result in cost per deciview of visibility improvement from $16.7 million to $17.8 million at the Washakie WA, the highest impacted Class I area.

The USFWS stated that when these values are compared to other single Class I area impacts for some other NO_X BART proposals as summarized below, it would indicate that they each could be considered as reasonable. The USFWS stated that when total annual cost for each of the three NO_X control alternatives is divided by the respective visibility improvement for all affected Class I areas (as discussed above for SO_2) they result in cost per deciview of visibility improvement from $4.7 million to $5.0 million, which is a very reasonable visibility cost. USFWS stated that since the cost per ton of NO_X removal and the cost per deciview of visibility improvement are both reasonable, at least the Separated Over-fire Air (SOFA)-only or, preferably SOFA plus Selective Non-Catalytic Reduction (SNCR) should definitely be considered as feasible and cost-effective NO_X control alternatives and be accepted as BART for Corette.

Response: We disagree that SOFA or SOFA+SNCR should be accepted as BART for Corette. The BART Guidelines require that cost effectiveness be calculated in terms of annualized dollars per ton of pollutant removed, or $/ton. 70 FR 739167. The BART Guidelines list the $/deciview ratio as an additional cost effectiveness metric that can be employed along with $/ton for use in a BART evaluation. However, we did not use this metric for the reasons that were explained in other responses. As we stated in the proposed FIP, we weighed costs against the anticipated visibility impacts and we explained that any of the control options would have a positive impact on visibility; however, the cost of controls was not justified by the visibility improvement. As we have explained elsewhere, in our proposal, we considered the visibility improvement at all Class I areas within 300 km of the subject BART unit.

In addition, we note that the UFWS seems to have miscalculated the dollars per deciview values for the NO_X control options.

Comment: The USFS stated the BART determinations for Corette are not consistent with previous BART demonstrations that have been made for other facilities in Montana, as well as with decisions EPA has approved in other SIPs. And that EPA has identified control options for both NO_X and SO_2 that are technically feasible and cost effective. USFS stated that it is their understanding that EPA has also determined that the visibility improvement does not justify the cost of the additional controls.

Response: We disagree. As the commenter has noted, we rejected additional controls for Corette since the visibility improvement does not justify the cost of controls. Moreover, the USFWS has not identified how this is inconsistent with other BART determinations in Montana or elsewhere.

Comment: WEG stated that EPA arbitrarily rejected requiring SCR as BART for NO_X emissions from Corette and that we stated in the proposed FIP that the control technology would be cost-effective and achieve greater visibility benefits—in favor of no additional controls. WEG stated that the EPA's proposed BART determination is inconsistent with the CAA and the Agency's own record. WEG stated that that under the factors required to be considered by EPA in determining BART under the CAA, SCR would constitute BART. WEG stated that EPA found that SCR for Corette would not be cost-prohibitive and that the Agency also identified no energy and nonair quality impacts that would mitigate against the use of SCR, or any remaining useful life issues that would preclude the use of SCR. WEG stated that with regard to visibility improvement, the EPA further found that SCR, as opposed to doing nothing, would achieve greater visibility improvements and that given that SCR represents ''the best system of continuous emission control technology available'' (40 CFR 51.308(e)(1)(ii)), there appears to be no reason to dismiss SCR as BART for Corette. WEG stated that the EPA asserted that SCR for Corette ''is not justified by the visibility improvement.'' Yet, the proposed FIP indicates that with the use of SCR, visibility improvements in the most impacted Class I area, the Washakie WA, would be 264%, an enormous improvement from current conditions. WEG stated that SCR would have a visibility improvement of 0.264 deciview and that SCR would reduce visibility impairment at seven different Class I areas, and that SCR would cumulatively improve visibility amongst the seven impacted Class I areas by 0.939 deciview. 77 FR 24042.

WEG stated that such cumulative visibility improvements do not appear to be unreasonable, but that in this case, the EPA appears to believe that the level of visibility improvement is not significant enough to justify the use of SCR. WEG stated that the proposed FIP provides no information or analysis to indicate that EPA's belief is not anything more than an arbitrary claim and that there is no explanation as to why the EPA believed the level of improvement with the use of SCR was somehow discountable or insignificant. WEG stated that the EPA's logic is further belied by the fact that the FIP will fail to achieve meaningful reasonable progress in attaining natural visibility conditions in Class I areas in Montana and that given the prospect of such dismal progress in achieving natural visibility, it is reasonable to presume that any improvement in visibility, no matter how small, would be significant. WEG stated that the EPA failed to provide any information or analysis in the proposed FIP or the supporting record suggesting otherwise. WEG stated that although it is true that EPA is allowed to consider the degree in improvement in visibility in determining BART, there is no indication that this factor could be interpreted to allow the Agency to make arbitrary determinations that a 264% improvement in visibility under a plan that already contains unreasonable RPGs is insignificant or otherwise not worthy of regulatory action under the CAA's regional haze program.

Response: We disagree. We did not arbitrarily reject SCR. Our proposal clearly laid out the bases for our proposed BART determination for NO_X for Corette. Our regulations define BART as an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. The BART analysis identifies the best system of continuous emission reduction taking into account:

(1) The available retrofit control options, (2) Any pollution control equipment in use at the source (which affects the availability of options and their impacts), (3) The costs of compliance with control options, (4) The remaining useful life of the facility, (5) The energy and nonair quality environmental impacts of control options (6) The visibility impacts analysis. 70 FR 39163.

As the final BART Guidelines explain, both the 2001 proposal and the 2004 reproposal requested comments on two options for evaluating the ranked options. The first option was similar to the process that WEG implies should have been followed, where the most stringent control option must be chosen as long as it does not impose unreasonable costs of compliance or energy and nonair quality environmental impacts would justify selection of an alternative control option. 70 FR 39130. The second option was:

An alternative decision-making approach that would not begin with an evaluation of the most stringent control option. For example, States could choose to begin the BART determination process by evaluating the least stringent technically feasible control option or by evaluating an intermediate control option drawn from the range of technically feasible control alternatives. Under this approach, States would then consider the additional emissions reductions, costs, and other effects (if any) of successively more stringent control options. Under such an approach, States would still be required to (1) display all of the options and identify the average and incremental costs of each option; (2) consider the energy and nonair quality environmental impacts of each option; and (3) provide a justification for adopting the technology selected as the ''best'' level of control, including an explanation of its decision to reject the other control technologies identified in the BART determination.

In the final guidelines, EPA ''decided that States should retain the discretion to evaluate control options in whatever order they choose, so long as the State explains its analysis of the CAA factors.'' 70 FR 39130. The BART Guidelines state that we ''have discretion to determine the order in which you should evaluate control options for BART'' and that we ''should provide a justification for adopting the technology that you select as the ''best'' level of control, including an explanation of the CAA factors that led you to choose that option over other control levels.'' 70 FR 39170.

We explained our analysis of the five factors and explained that the CAA factors that led to our decision were cost-effectiveness and visibility improvement. The cost-effectiveness of SOFA + SCR was determined to be $4,491/ton and the visibility improvement at the most impacted Class I area, Washakie WA, was 0.264 deciview. The impact at additional Class I areas was shown in Tables 123 and 124. 77 FR 24042. When we weighed the costs against the anticipated visibility improvement for Corette the cost of controls was not justified by the limited visibility improvement. 77 FR 24043.

With regard to WEG's claim that SCR would result in a visibility improvement of 264%, WEG used a fundamentally flawed approach to calculate visibility improvements. Using WEG's approach, a 0.1 deciview change would produce a 1000% improvement in visibility compared to a 0.01 deciview change. In fact, the change would be 0.09 deciview or about 1% relative to natural visibility conditions. The approach that WEG used to calculate percent visibility improvement is mathematically incorrect. WEG compared a 0.264 deciview change to a zero deciview change and arbitrarily called this a 264% improvement in visibility. To get a more accurate estimate, you can use the rule of thumb that 0.5 deciview is approximately equivalent to a 5% change in perceived visibility. The 0.264 deciview change would be approximately a 2.6% improvement in visibility relative to natural visibility conditions. WEG makes the same mistake on page 3 in the comment on Colstrip where they state: ''with the use of SCR, visibility improvements in the most impacted Class I areas would be around 50% greater than with the use of SNCR.'' Here they compared 0.784 deciview with SCR to 0.518 deciview with SNCR, and concluded that SCR provides a 50% visibility improvement over SNCR. Again, using the rule of thumb, this would be about a 2.6% difference in perceived visibility between SCR and SNCR relative to natural visibility conditions.

The BART Guidelines state that to make the net visibility improvement determination you should, ''assess the visibility improvement based on the modeled change in visibility impacts for the pre-control and post-control emission scenarios. You have flexibility to assess visibility improvements due to BART controls by one or more methods. You may consider the frequency, magnitude, and duration components of impairment.'' 70 FR 39170. The BART Guidelines also state that, ''Comparison thresholds can be used in a number of ways in evaluating visibility improvement (e.g. the number of days or hours that the threshold was exceeded, a single threshold for determining whether a change in impacts is significant, or a threshold representing an x percent change in improvement.'' 70 FR 39170. Our proposal shows the baseline visibility impact in deciviews, the visibility improvement in deciviews, the number of Class I areas impacted within 300 km, and fewer days impacted more than 0.5 deciview in Tables 123 and 124 and these are more appropriate metrics for evaluating visibility impact.

We disagree with WEG's statement that the FIP will fail to achieve meaningful reasonable progress in attaining natural visibility conditions in Class I areas in Montana and that given the prospect of such dismal progress in achieving natural visibility, it is reasonable to presume that any improvement in visibility, no matter how small, would be significant. We have explained in other responses that 40 CFR 51.308(d)(1)(ii) states that, ''if the State establishes a reasonable progress goal that provides for a slower rate of improvement in visibility that the rate that would be needed to attain natural conditions by 2064, the State must demonstrate, based on the factors in paragraph (d)(1)(i)(A) of this section, that the rate of progress for the implementation plan to attain natural conditions by 2064 is not reasonable; and that the progress goal adopted by the State is reasonable. The State must provide the public for review as part of its implementation plan an assessment of the number of years it would take to attain natural conditions if visibility improvement continues at the rate of progress selected by the State as reasonable.'' We explained in other responses how we have met those requirements.

I. Comments on Reasonable Progress and Long Term Strategy

Comment: A commenter stated that based on the WRAP emissions inventory and air quality modeling, EPA proposed reasonable progress goals for the 20% worst visibility days for the Montana Class I areas that are significantly less (16–51%) than the uniform rate of progress by 2018 and that no Montana Class I area is projected to achieve natural visibility conditions by 2064. The commenter stated that EPA projects that, at best, the national goal will not be met for 135 years at Cabinet Mountains WA and, at worst, for 437 years at the Medicine Lake WA.

The commenter stated that the WRAP inventory indicates that point sources contribute 71% of Montana's total SO_2 emissions, yet point source SO_2 emissions in Montana are projected to be reduced by less than 1% by 2018 (this includes SO_2 reductions for BART for Colstrip Units 1 and 2). This change in point source emissions inventory is considerably less than projected by other states in Region 8, yet EPA has determined that no additional SO_2 controls are reasonable. The commenter stated that the WRAP inventory projects that point source NO_X emissions would be reduced by 3% (23,000 tons per year), primarily due to estimated NO_X reductions at Colstrip and that EPA's RP analyses determined that $282 per ton for NO_X reduction at Devon Energy was cost effective, but NO_X controls for all other facilities were not cost effective. Several controls were below the cost of $4,659 for SO_2 controls at Corette Generating Station that EPA determined were cost effective for BART. Given the lack of progress in improving visibility at the Class I areas, EPA needs to reconsider the cost effectiveness of point source SO_2 and NO_X controls.

Response: We disagree that we should reconsider the cost effectiveness of point source controls given the lack of progress in improving visibility at the Class I areas. In determining the measures necessary to make reasonable progress and in selecting RPGs for mandatory Class I areas within Montana, we took into account the following four factors into consideration: costs of compliance; time necessary for compliance; energy and nonair quality environmental impacts of compliance; and remaining useful life of any potentially affected sources. CAA section 169A(g)(1) and 40 CFR 51.308(d)(1)(i)(A). In the FIP, we demonstrated how these four factors were considered. 40 CFR 51.308(d)(1)(ii) allows for a slower rate of improvement in visibility than the URP, as long as it is demonstrated that based on these four factors, it is not reasonable to achieve the URP and that the selected RPG is reasonable. CAA section 169A(g)(1) and 40 CFR 51.308(d)(1)(i)(A). We respond to specific critiques of our four-factor analyses elsewhere. To the extent that the commenter is stating that cost-effectiveness is a fixed value and must be the same whether a source is subject to BART or RP, we disagree. While the Regional Haze Rule may allow us to establish a bright line for some of the factors such as cost-effectiveness and visibility, we are not required to do so, and have not done so for this action.

Comment: A commenter stated that oil and gas development has increased markedly in Montana and neighboring states since the initial inventory projections provided by the WRAP in 2007 and that EPA should compare the most recent (Phase III) oil and gas emissions inventory to that used in the WRAP source apportionment modeling and discuss the implications of future oil and gas development for visibility at Montana Class I areas.

Response: We disagree that we should reevaluate the oil and gas inventory and discuss the implications of future oil and gas development for visibility at Montana Class I areas at this time. 40 CFR 51.308(d)(3)(iii) requires us to document the technical basis, including modeling, monitoring and emissions information on which we relied. It also requires that we identify the baseline emission inventory on which our strategies are based. As stated in the proposal, an emissions inventory for each pollutant was developed by WRAP for Montana and these inventories were used as inputs to photochemical modeling that was used to determine the 2018 reasonable progress goal. 77 FR 24047 and 77 FR 24054. 40 CFR 51.308(d)(3)(iii) allows us to rely on the technical analysis developed by the WRAP, which we have done. We recognize that emission inventories are dynamic, but at this time it is not necessary to reevaluate the emission inventories. The Regional Haze Rule recognizes the need for periodic progress evaluation and requires progress reports to be submitted every five years. 40 CFR 51.308(g)(4) requires this report to include, ''[A]an analysis tracking the change over the past five years in emissions of pollutants contributing to visibility impairment from all sources and activities within the state.'' As we explained in our proposal, we will update the statewide emissions inventories periodically or as necessary and review emissions information from other states and future emissions projections.

Comment: MDEQ stated that EPA fails to consider the potential benefits of the Mercury Air Toxics Standard, the new NO_X and SO_2 NAAQS, the forthcoming Boiler MACT, and other rules that will significantly impact $PM_{2.5}$, SO_2 and NO_2 emissions in its LTS.

Response: We are sensitive to the challenges of coordinating compliance with a variety of rules. However, to the extent that MDEQ is implying that we should have considered the potential benefits of possible future regulations in our LTS, we disagree. As explained in our proposed FIP, in order to establish RPGs for the Class I areas in Montana and to determine the controls needed for the LTS, we followed the process established in the Regional Haze Rule. The anticipated visibility improvement in 2018 in all Montana Class I areas accounting for all existing enforceable federal and state regulations already in place was considered. 77 FR 24055. With regard to regulations that are not yet final, we cannot speculate on unknown reductions from anticipated future federal or state regulations prior to those actions completing the full regulatory process. None of the Montana sources have notified us that they will be reducing emissions as a result of future regulation and we have no basis for estimating what those emissions may be. Without an enforceable commitment, we cannot assume that additional reductions will be achieved and we cannot account for them in our LTS for the Regional Haze FIP. MDEQ has not provided information to indicate that anything in the Regional Haze FIP will interfere with the requirements of other regulations. In fact, where additional controls are required, we would expect that the lower emission limit would make it easier to comply with future regulations that also require lower emission limits. We note that the Regional Haze FIP requires compliance with a specific emission limit and not necessarily the installation of a specific control technology and that sources have a full five years after the finalization of the FIP to comply with any emission limit that would require the installation of additional control technology.

Comment: MDEQ suggested that we include all smoke emissions from open burning and wildfires in the natural background estimates and recalculate URP and RPGs in each of the State's Class I areas with these adjusted background levels. MDEQ perceived fire to be the major contributing factor to the State's visibility impairment, and claimed that EPA does not make a realistic allowance for smoke contributions to haze in Montana.

Response: We agree that industrial facilities are not the only causes of haze, but we disagree that we should make adjustments to the inventories, the URP, or the RPGs. Our action considered the many contributors to haze including industrial facilities. It is not appropriate to consider open burning as natural background because open burning is anthropogenic. In our proposal, the emissions inventory appropriately included natural (non-anthropogenic) wildfire and anthropogenic sources such as open burning. 77 FR 24093. In developing a LTS, 40 CFR 51.308(d)(3)(iv) requires us to consider all anthropogenic sources. More specifically, 40 CFR 51.308(d)(3)(v)(E) requires the LTS to address smoke management techniques for agricultural and forestry management techniques. We note that our proposed action also proposed to approve the revisions to the paragraph titled ''Smoke Management'' of Title 17, Chapter 8, Subchapter 6, Open Burning as meeting the requirement in 40 CFR 308(d)(3)(v)(E) because the plan control emissions from these sources by requiring BACT and takes into consideration the visibility impacts on mandatory Class I areas.

Regardless of the contribution from smoke emissions, 40 CFR 51.308(d)(3)(iv) states, ''The State must identify all anthropogenic sources of visibility impairment considered by the State in developing its long-term strategy. The State should consider major and minor stationary sources, mobile sources, and area sources.'' In this case, we acted in the place of Montana and were required to abide by the same requirement to consider point sources. 40 CFR 51.308(d)(1)(ii) states that, ''if the State establishes a reasonable progress goal that provides for a slower rate of improvement in visibility that the rate that would be needed to attain natural conditions by 2064, the State must demonstrate, based on the factors in paragraph (d)(1)(i)(A) of this section, that the rate of progress for the implementation plan to attain natural conditions by 2064 is not reasonable; and that the progress goal adopted by the State is reasonable. The State must provide the public for review as part of its implementation plan an assessment of the number of years it would take to attain natural conditions if visibility improvement continues at the rate of progress selected by the State as reasonable.'' In this case, we are acting in the place of Montana. In determining the measures necessary to make reasonable progress and in selecting RPGs for mandatory Class I areas within Montana, we evaluated major and minor point sources according to the four factors required by 40 CFR 51.308 (d)(1)(i)(A) (costs of compliance; time necessary for compliance; energy and nonair quality environmental impacts of compliance; and remaining useful life of any potentially affected sources CAA section 169A(g)(1) and 40 CFR 51.308(d)(1)(i)(A)). In addition, 40 CFR 51.308(e) requires states to make a BART determination for each BART-eligible source and in that determination, the state must consider the five statutory factors.

The requirements of 40 CFR 51.308(d)(3)(iv) and 40 CFR 51.308(e) are not dependent on the showing of a certain amount of impairment from point sources.

EPA recognized that variability in natural sources of visibility impairment causes variability in natural haze levels as described in its ''Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule.'' [54] The preamble to the BART Guidelines (70 FR 39124) describes an approach used to measure progress toward natural visibility in Mandatory Class I areas that includes a URP toward natural conditions for the 20% worst days and no degradation of visibility on the 20% best days. The use of the 20% worst natural conditions days in the calculation of the URP takes into consideration visibility impairment from wild fires, windblown dust and other natural sources of haze.[55] 70 FR 39124. The Guidance for Estimating Natural Visibility Conditions also discusses the use of the 20% best and worst estimates of natural visibility, provides for revisions to these estimates as better data becomes available, and discusses possible approaches for refining natural conditions estimates.[56]

For the evaluation of visibility impacts for BART sources, EPA recommended the use of the natural visibility baseline for the 20% best days for comparison to the ''cause or contribute'' applicability thresholds. This estimated baseline is reasonably conservative and consistent with the goal of attaining natural visibility conditions. While EPA recognizes that there are natural sources of haze, the use of the 20% worst natural visibility days is inappropriate for the ''cause or contribute'' applicability thresholds. For example, if BART source visibility impacts were evaluated in comparison to days with very poor natural visibility resulting from nearby wild fires or dust storms, the BART source impacts would be significantly reduced relative to these poor natural visibility conditions and would not be protective of natural visibility on the best 20% days.

Comment: MDEQ insisted that visibility issues in the Western U.S. are less stationary source driven than in the Eastern U.S., and that greater understanding of this difference has developed since Congress passed the Visibility Protection Act of 1977 and the visibility statute of the CAA Amendments of 1990.

Response: To the extent that MDEQ is implying that we are not required to analyze controls for stationary sources, we disagree. As explained in other responses, 40 CFR 51.308(d)(3)(iv) requires us to identify all anthropogenic sources of visibility impairment considered in developing our long term strategy. It specifically states that we should consider major and minor stationary sources, mobile sources, and area sources. Please see the language of 40 CFR 51.308(e) in the response to the previous comment. The requirements of 40 CFR 51.308(d)(3)(iv) and 40 CFR 51.308(e) are not dependant on the showing of a certain amount of impairment from point sources.

Comment: A commenter stated that BART sources such as Corette should also be considered under reasonable progress and that this would be consistent with actions EPA has approved in other SIPs. The commenter stated that EPA is using visibility improvement as measured by Q over D values as an indirect measure of the benefit of additional controls under reasonable progress and that it is their understanding that this is not supported under the Regional Haze Rule as reasonable progress decisions do not consider visibility improvement. The commenter requested that control options considered technologically feasible and cost effective under BART also be considered under reasonable progress.

Response: We disagree that BART sources need to be re-evaluated for the purposes of reasonable progress and that, under the Regional Haze Rule, reasonable progress determinations may not consider visibility improvement. Our RP Guidance states, ''Since the BART analysis is based, in part, on an assessment of many of the same factors that must be addressed in establishing the RPG, it is reasonable to conclude that any control requirements imposed in the BART determination also satisfy the RPG-related requirements for source review in the first RPG planning period. Hence you may conclude that no additional emissions controls are necessary for these sources in the first planning period.'' [57] The EPA has concluded that, based on the similarity of many of the same factors for both BART and reasonable progress, that no additional emissions controls are necessary for BART sources for this planning period. The commenter has given us no basis to change that conclusion: Regardless of whether any states have chosen to reevaluate BART sources for reasonable progress, the

[54] Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule, U.S. Environmental Protection Agency, September 2003. *http://www.epa.gov/ttncaaa1/t1/memoranda/rh-envcurhr-gd.pdf,* page 1–1 (Guidance for Estimating Natural visibility Conditions). The guidance states that, ''Natural visibility conditions represent the long-term degree of visibility that is estimated to exist in a given mandatory Federal Class I area in the absence of human-caused impairment. It is recognized that natural visibility conditions are not constant, but rather they vary with changing natural processes (e.g., windblown dust, fire, volcanic activity, biogenic emissions). Specific natural events can lead to high short-term concentrations of particulate matter and its precursors. However, for the purpose of this guidance and implementation of the regional haze program, natural visibility conditions represents a long-term average condition analogous to the 5-year average best- and worst-day conditions that are tracked under the regional haze program.''

[55] The preamble further stated that, ''with each subsequent SIP revision, the estimates of natural conditions for each mandatory Federal Class I area may be reviewed and revised as appropriate as the technical basis for estimates of natural conditions improve.''

[56] Guidance for Estimating Natural Visibility Conditions, p.3–1 to 3–4.

[57] Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, U.S. Environmental Protection Agency, (''Reasonable Progress Guidance'') (June 1, 2007) p.4–2—4–3.

Regional Haze Rule does not require states to do so. With regard to the statement about using visibility improvement to evaluate additional controls under reasonable progress, EPA's reasonable progress guidance states: ''In determining reasonable progress, CAA section 169A(g)(1) requires States to take into consideration a number of factors. However, you have flexibility in how to take into consideration these statutory factors and any other factors that you have determined to be relevant.'' [58] The potential reduction in quantity over distance (Q/D) is a factor that we consider to be relevant because the goal of the Regional Haze Rule is to improve visibility. The commenter has not cited any authority supporting the position that visibility improvements may not be considered in reasonable progress determinations and therefore has given us no basis to change our use of this factor.

Comment: A commenter stated that the proposal fails to achieve reasonable progress. The commenter explained that the proposal will leave visibility in the parks and WAs that are affected by Montana sources impaired for hundreds of years into the future, nonetheless, we propose no additional emission reductions from Montana's stationary sources.

Response: We disagree that the FIP fails to achieve reasonable progress. 40 CFR 51.308(d)(1)(ii) states:

> If the State establishes a reasonable progress goal that provides for a slower rate of improvement in visibility than the rate that would be needed to attain natural conditions by 2064, the State must demonstrate, based on the factors in paragraph (d)(1)(i)(A) of this section, that the rate of progress for the implementation plan to attain natural conditions by 2064 is not reasonable; and that the progress goal adopted by the State is reasonable. The State must provide the public for review as part of its implementation plan an assessment of the number of years it would take to attain natural conditions if visibility improvement continues at the rate of progress selected by the State as reasonable.

In determining the measures necessary to make reasonable progress and in selecting RPGs for mandatory Class I areas within Montana, we took into account the following four factors into consideration: Costs of compliance; time necessary for compliance; energy and nonair quality environmental impacts of compliance; and remaining useful life of any potentially affected sources. CAA section 169A(g)(1) and 40 CFR 51.308(d)(1)(i)(A). In the FIP, we demonstrated how these four factors were considered and we also provided, in Table 197, an assessment of the number of years it would take to attain natural conditions if visibility improvement continues at the rate of progress that we selected was reasonable. We respond to specific critiques of our four-factor analyses elsewhere.

Comment: A commenter stated that EPA failed to evaluate controls on all BART-subject sources to meet reasonable progress requirements and that EPA stated that the BART analyses for these facilities are similar to the requisite reasonable progress analysis. 77 FR at 24059. The commenter stated that EPA has ensured that Montana will not achieve reasonable progress toward natural visibility conditions at Class I areas affected by Colstrip and Corette and that EPA's approach is flawed legally and factually. The commenter stated that EPA's approach fails to distinguish between the purposes of BART and the long-term strategy under the Regional Haze Rule and that while both are mechanisms to help states achieve reasonable progress, BART is applied to a given source—for the purpose of eliminating or reducing visibility impairment caused or contributed to by that source. 42 U.S.C. section 7491(b)(2)(A). The commenter stated that rather than focusing on specific sources, the development of a long-term strategy requires EPA to look at existing visibility impairment—after emissions reductions due to BART and other strategies are accounted for—and attribute responsibility for eliminating that impairment among sources and categories. 40 CFR 51.308(d)(1). The commenter stated that in this way, the states and EPA maintain flexibility to determine the most effective and efficient way to eliminate haze pollution when technology mandates on specified sources have not done the job. The commenter stated that therefore, measures within a long-term strategy are required to achieve reasonable progress above and beyond BART and that by categorically eliminating all BART-subject sources from its reasonable progress analysis, EPA has failed to meet its obligation to determine whether emissions reductions from these sources beyond those required by BART are necessary to achieve the national goal of eliminating visibility impairment.

Response: We disagree that BART sources need to be re-evaluated for the purposes of reasonable progress. Our reasonable progress guidance states:

> Since the BART analysis is based, in part, on an assessment of many of the same factors that must be addressed in establishing the RPG, it is reasonable to conclude that any control requirements imposed in the BART determination also satisfy the RPG-related requirements for source review in the first RPG planning period. Hence you may conclude that no additional emissions controls are necessary for these sources in the first planning period.[59]

The commenter has given no reason for us to change this position.

Comment: A commenter stated that EPA's approach essentially duplicates all of the errors from its BART analysis in its reasonable progress analysis and that in particular, EPA's incremental visibility justification for dismissing the most stringent pollution control technologies is especially inappropriate in the reasonable progress framework. The commenter stated that incremental visibility improvement is not included among the four factors to be considered in establishing reasonable progress measures. 40 CFR 51.308(d)(1)(i)(A). The commenter stated that if this justification is applied to eliminate the most effective pollution-reduction measures at every source—especially the largest and oldest sources that are subject to BART—then Montana may never make reasonable progress toward achieving natural visibility conditions.

Response: We disagree that there are errors in our approach for BART and reasonable progress for the same reasons we have discussed previously. Pursuant to 40 CFR 51.308(e)(A) for our BART analyses, we considered the following five factors in our analysis: The appropriate level of BART control; the cost of compliance; the energy and nonair quality environmental impacts; any pollution control equipment in use at the source; the remaining useful life of the source; and the degree of improvement which may be reasonably anticipated to result from the use of such technology. We agree that visibility improvement is not one of the four factors required by CAA section 169A(g)(1) and 40 CFR 51.308(d)(1)(i)(A), however, it (along with other relevant factors) can be considered when determining controls that should be required for reasonable progress. Our reasonable progress guidance states: ''In determining reasonable progress, CAA section 169A(g)(1) requires States to take into consideration a number of factors. However, you have flexibility in how to take into consideration these statutory factors and any other factors that you have determined to be relevant.'' [60] For certain potentially affected sources, we considered Q/D and potential reductions in Q/D, which are relevant to

[58] Reasonable Progress Guidance, p.5–1.

[59] Reasonable Progress Guidance, p. 4–2—4–3.

[60] Reasonable Progress Guidance, p. 5–1.

the goal of the Regional Haze Rule, improving visibility.

Comments: A commenter stated that EPA failed to require that Colstrip Units 1 and 2 and Corette make emissions reductions that were relied upon by the WRAP, EPA, and states neighboring Montana in establishing reasonable progress goals, and that if EPA fails to revise its BART determinations for Colstrip Units 1 and 2 and Corette, EPA must require additional reductions of visibility-impairing pollutants in its long-term strategy. Another commenter stated that EPA should have required SCR+SOFA as BART for Colstrip Units 1 and 2 and should have required SOFA+SCR and a dry scrubber/baghouse for Corette, but even if EPA were to justify its contrary BART finding in response to these comments, EPA should have required SCR+SOFA and a dry scrubber/baghouse at these units as part of its long term strategy. The commenter explained that where sources within a state contributes to visibility within another state's Class I area or areas, the state has an obligation to adopt controls necessary to ensure it achieves its share of the pollution reductions that are required to meet the reasonable progress goals set for the subject Class I area.

Response: We do not agree that we must revise our BART determinations for Colstrip Units 1 and 2 and Corette. We have stated in other actions addressing regional haze that a plan that provides for emission reductions consistent with the assumptions underlying the WRAP modeling will ensure that a State is not interfering with measures designed to protect visibility in other states. See e.g. 76 FR 491, 496–497 (Jan. 5, 2011). Similarly, a plan that is consistent with the assumptions underlying the modeling used to establish RPGs in a state likely will include the measures necessary to achieve those RPGs. However, there is no requirement that a SIP (or FIP) adopt the assumptions underlying the models as enforceable requirements. The air quality models used to support the regional haze SIPs are extremely complex, and due to the time consuming nature of performing the modeling, this work was performed early in the process. The emissions projections by the RPOs, relied upon in the air quality modeling, incorporated the best available information at the time from the states, and utilized the appropriate methods and models to provide a prediction of emissions from all source categories into the future. There was an inherent amount of uncertainty in the assumed emissions from all sources, including emissions from BART-eligible sources, as the final control decisions by all of the states were not yet complete. The WRAP used their best estimates of what regional haze SIPs would achieve as inputs for the modeling. In the end, reductions resulting from BART determinations based on the statutory factors may differ from those estimates.

One relevant requirement cited by the commenter, at 40 CFR 51.308(d)(3)(ii), is that EPA must demonstrate that it has included all measures necessary to obtain its share of the emission reductions needed to meet the RPGs for Class I areas where it causes or contributes to impairment. Montana's neighboring Class I states originally set the reasonable progress goals in their SIP based on emission reductions expected to be achieved through application of presumptive BART and other emission reductions qualified for that purpose. These neighboring states had the opportunity to comment on the regional haze FIP, and did not ask for additional emission reductions. We also note that the RPGs are not enforceable goals. Neighboring states will have the responsibility to consider whether other reasonable control measures are appropriate to ensure reasonable progress during subsequent periodic progress reports and regional haze SIP revisions as required by 40 CFR 51.308(f)–(h), and may at that time consider asking EPA for additional emission reductions.

With respect to Colstrip Units 1 and 2, we note that our FIP achieves SO_2 emissions reductions well beyond those assumed in the WRAP PRP18b emissions inventory. Specifically, at Units 1 and 2, assuming operation at 85% of capacity, our FIP achieves reductions of 7,538 tpy of SO_2, which is 1,504 tpy better than indicated by the PRP18b projections. By way of comparison, again assuming operation at 85% of capacity, our FIP achieves reductions of 6,652 tpy of NO_X for Colstrip Units 1 and 2, which is 1,709 tpy below that indicated by the PRP18b projections. Because the additional SO_2 reductions are close to the shortfall in NO_X reductions at Colstrip Units 1 and 2, and as SO_2 may have a greater impact than NO_X on visibility in Montana, we find that the overall emissions reductions achieved at Colstrip Units 1 and 2 will result in similar visibility improvement to the emissions reductions assumed in the WRAP PRP18b projections.

With respect to Corette, the commenter has overstated the discrepancy between the emissions associated with our BART determination and the PRP18b projections, because the commenter has compared WRAP projections based on annual emissions with emissions limits that are on a 30-day rolling average. In addition, we note that we have revised the NO_X and SO_2 emission limits for Corette in our FIP to be somewhat more stringent than what we proposed (and more reflective of actual emissions with existing controls). Finally, the WRAP projections do not reflect application of SOFA+SCR or a dry scrubber/baghouse to Corette. Therefore, the projections do not support the commenter's position that these controls are required.

Moreover, there are NO_X reductions at other BART sources that are greater than assumed by WRAP. At Ash Grove and Holcim, the total reductions from our FIP are significantly more relative to the PRP18b projections that the WRAP used. In conclusion, our FIP contains additional emission reductions at BART sources that largely offset any shortfall at Colstrip Units 1 and 2 and Corette.

Comment: A commenter stated that our reasonable progress goals are unreasonable, unsupported, and effectively contrary to the CAA's requirements that we assure reasonable progress in achieving natural visibility conditions in Class I areas. The commenter stated that the proposed RPGs, at a minimum, double the timeframe required to achieve natural visibility conditions for every Class I area in Montana and that this is not reasonable. The commenter also stated that the reasonable progress goals are unreasonable based on the statutory factors that must be considered by EPA under 42 U.S.C. 7491(g)(1), and that we provided two reasons for asserting that the reasonable progress goals are reasonable: That our four factor analyses resulted in limited opportunities for reasonable progress controls for point sources and that significant visibility impairment is caused by non-anthropogenic sources in and outside Montana. The commenter stated that with regard to the latter issue of non-anthropogenic sources in and outside of Montana, this is not a statutory factor that EPA is allowed to consider in establishing RPGs.

Response: We disagree. It is not necessarily unreasonable for the RPGs to reflect a longer period of time than the URP. The URP is simply calculated by dividing the difference between the present visibility conditions and natural visibility conditions by the number of years between the baseline and 2064. It assumes a steady rate of progress and does not take into account the four statutory factors for determining reasonable progress or any additional factors that warrant consideration. As a result, the RPGs, which do reflect consideration of these factors, may well vary from the URP.

In determining reasonable progress controls, EPA did consider the statutory factors for determining reasonable progress set out in 42 U.S.C. 7491(g)(1). To the extent that the commenter argues with our evaluation of these factors, we respond to specific comments on our evaluation of these factors elsewhere.

The commenter is correct that consideration of non-anthropogenic sources in and outside of Montana is not one of the statutory four factors that must be considered under 42 U.S.C. 7491(g)(1). However, EPA's reasonable progress guidance states: ''In determining reasonable progress, CAA section 169A(g)(1) requires States to take into consideration a number of factors. However, you have flexibility in how to take into consideration these statutory factors and any other factors that you have determined to be relevant.'' [61] The data demonstrating that significant visibility impairment is caused by non-anthropogenic sources in and outside Montana is relevant because it diminishes the potential improvement that might be realized through controlling an individual point source within Montana. Therefore, it was proper for EPA to consider this additional factor.

Comment: A commenter stated that based on the four factors set forth under the CAA, it appears that EPA grossly overstated its assertion that there are only limited opportunities for reasonable controls for point sources. The commenter stated that this is particularly the case with regard to NO_X emissions from coal-fired EGUs in Montana. The commenter stated that our proposal disclosed that for every coal-fired EGU assessed under the four-factor analysis for determining RPGs, including Colstrip units 3 and 4, Colstrip Energy, and the Lewis and Clark Station, that cost-effective SCR control technology could achieve greater NO_X emissions reductions and greater visibility improvements than under our FIP. The commenter stated that despite this, we rejected SCR as a control option and ultimately adopted no NO_X emission controls for these four sources. The commenter stated that we also rejected SCR as BART for Colstrip Units 1 and 2 and the Corette coal-fired EGUs, even though we found SCR to be a cost-effective and reasonable technology, we rejected it in favor of weaker controls. The commenter concluded that we did not show that any of the four factors would mitigate against additional control and stronger RPGs. The commenter stated that our assertion that there would be no degradation is not reasonable or legally justified and that we must establish our reasonable progress goals based on all coal-fired EGUs using SCR to reduce NO_X emissions.

Response: We disagree that the four factor analyses for EGUs that are potentially affected reasonable progress sources mandate the addition of SCR and that visibility, although not one of the four statutory factors that are required to be considered, cannot be considered in determining appropriate controls under reasonable progress. EPA's reasonable progress guidance states: ''In determining reasonable progress, CAA section 169A(g)(1) requires States to take into consideration a number of factors. However, you have flexibility in how to take into consideration these statutory factors and any other factors that you have determined to be relevant.'' [62] For example, the potential reduction in Q/D is a factor that we consider to be relevant because the goal of the Regional Haze Rule is to improve visibility at Class I areas. We note that the commenter, in citing potential visibility improvement at the facilities mentioned, undercuts their own argument that the four statutory RP factors by themselves, without consideration of other factors, demonstrate that EPA ''grossly overstated'' its conclusion that there are only limited opportunities for reasonable controls for point sources. Commenter misstated EPA's conclusions by stating that EPA ''found SCR to be a cost-effective and reasonable technology'' for the BART EGUs. While we did state that the cost on a dollars per ton basis was cost-effective, we also explained that the cost of SOFA + SCR was not justified by the visibility improvement. 77 FR 24027, 77 FR 24035, and 77 FR 24043. The commenter misstated the requirements of the Regional Haze Rule. In examining potentially affected sources for possible controls and setting RPGs, EPA is not required to ''show that any of the four factors would mitigate against additional controls and stronger reasonable progress goals.'' Instead, EPA is required to consider the four statutory reasonable progress factors. In addition, EPA may consider additional, relevant factors such as visibility improvement from controls. To the extent that the comment argues with our determinations for particular potentially affected sources, we respond to specific criticisms elsewhere. With regard to commenter's statement that our basis for determining there would be no degradation on the least impaired days was unreasonable and not legally justified, we note that the commenter did not identify any flaw in our data or methodology in deriving Table 198 in the proposal. We therefore disagree with the statement.

Comment: PPL commented that to try to address visibility impairment only within the universe of point sources subject to potential EPA regulation within the United States is not reasonable and will not lead to achievement of Reasonable Progress Goals (RPGs). PPL stated further that EPA, in conjunction with other federal and state agencies and the FLMs, should re-evaluate some of the conclusions as to the uncontrollable nature of several listed significant contributors of SO_2 and NO_X. PPL stated that application of the BART analysis excludes consideration of a number of factors, including outside domain sources. PPL pointed out that the RPGs in the proposed FIP do not take into account the contribution of international emissions to the visibility, and do not address challenges faced by the state of Montana.

Response: To the extent that PPL commented that we are addressing visibility impairment only within the universe of point sources subject to potential EPA regulation within the United States, that we did not consider other sources of emissions, we disagree. As explained elsewhere, our action considered the many contributors to haze including all anthropogenic sources as required by 40 CFR 51.308(d)(3)(iv) and smoke management techniques for agricultural and forestry management techniques as required by 40 CFR 51.308(d)(3)(v)(E). In our proposal, the emissions inventory appropriately included natural (non-anthropogenic) wildfire and anthropogenic sources such as open burning and international emissions. We proposed approve the revisions to the smoke management section of Montana's Visibility SIP as meeting the requirement in 40 CFR 308(d)(3)(v)(E).

Comment: The NPS commented that EPA used inconsistent criteria in selecting reasonable progress controls.

Response: We disagree. As explained in other responses, in determining the measures necessary to make reasonable progress and in selecting RPGs for mandatory Class I areas within Montana, we took the following four factors into consideration: costs of compliance; time necessary for compliance; energy and nonair quality

[61] Reasonable Progress Guidance, p. 5–1.

[62] Reasonable Progress Guidance, p.5–1.

environmental impacts of compliance; and remaining useful life of any potentially affected sources. CAA section 169A(g)(1) and 40 CFR 51.308(d)(1)(i)(A). As also explained in other responses, we also considered potential visibility improvement in a general sense by considering the potential reduction in haze causing pollutants and also the distance from the source to the nearest Class I area. For Colstrip 3 and 4, we also considered visibility modeling results and have explained the reasoning for that decision in another response.

J. Comments on Colstrip Units 3 and 4

Comment: Some commenters agreed with EPA's conclusion not to require additional emissions controls at Colstrip Units 3 and 4. Commenters asserted that, given the aggressive pollution control technologies already in place, EPA properly concluded that additional controls for Reasonable Progress are not appropriate.

Response: We acknowledge the commenters' support for our decision not to require additional emission controls on Colstrip Units 3 and 4 in this planning period. Whether additional emission reductions from reasonable progress sources, including Colstrip Units 3 and 4, are necessary will be re-evaluated in subsequent planning periods.

Comment: Various commenters stated that we underestimated the costs of SNCR for Colstrip Units 3 and 4.

Response: We disagree that we underestimated the costs of SNCR for Colstrip Unit 3 and 4. For a further explanation, see our response to similar comments made in relation to SNCR costs for Colstrip Unit 1 and 2.

Comment: Commenters stated that they disagree with EPA's cost analysis for NO_X control technologies for Colstrip Units 3 and 4. In particular, commenters stated that we underestimated the capital costs and cost-effectiveness of these controls. Commenters referenced cost estimates submitted by PPL in September 2011 and February 2012, which show much higher capital costs and cost-effectiveness than those estimated by EPA.

Response: We disagree. We have rejected PPL's cost estimates for NO_X control options for Colstrip Units 3 and 4 for the same reasons that we rejected them for Colstrip Units 1 and 2. See previous responses to comments.

Comment: NPS stated that EPA modeled baseline visibility impacts at five Class I areas from Colstrip Units 3 & 4 using 2008–2010 emissions, while PPL modeled visibility impacts using 2001–2003 emissions. NPS agreed with the PPL modeling approach because it is consistent with EPA guidance to use the 2001–2003 pre-control emissions.

Response: See our response to a similar comment made in regard to the baseline emissions used for Colstrip Units 1 and 2.

Comment: NPS stated that after EPA concluded its statutory four-factor analysis of Colstrip 3 and 4, it created a new, ''Optional Factor: Modeled Visibility Impacts'' fifth factor, only for Colstrip 3 & 4. NPS further stated that this ''optional'' fifth factor is not required by statute or regulation, and that EPA only used it on one reasonable progress source (2 units) and did not explain what criteria it used to evaluate it.

Response: As we explained elsewhere, our RP Guidance allows for consideration of additional factors such as visibility impacts or benefits. Given the large annual emissions of NO_X and SO_2 from Colstrip Units 3 and 4 compared to other reasonable progress sources, we found that it was reasonable to model the visibility benefits and consider them when evaluating controls.

Comment: NPS stated that EPA has not provided criteria used in making the determination of what ''Costs of Compliance'' are reasonable, and its determinations vary significantly across Montana facilities.

Response: As we have explained elsewhere, while the Regional Haze Rule and BART Guidelines allow states to establish thresholds for cost-effectiveness, we are not required to do so and have not done so for this action. Also, our Reasonable Progress determinations were made based not just on the cost of compliance, but with consideration of the four factors along with additional information that was pertinent.

Comment: EarthJustice stated that EPA must set NO_X emission limits for Colstrip Units 3 and 4 based on SCR to help achieve reasonable progress. EarthJustice stated that EPA's analysis is skewed to underestimate the benefits of SCR, both in terms of control effectiveness and visibility improvement, and overestimates the costs. EarthJustice made claims regarding our cost analysis for Colstrip Units 3 and 4 that were very similar to the claims they made regarding Colstrip Units 1 and 2.

Response: We disagree. Below we address each of EarthJustice's arguments that support their assertion that SCR must be required for Colstrip Units 3 and 4.

Comment: EarthJustice stated that EPA underestimated the control effectiveness of SCR.

Response: See our response to similar comment made by EarthJustice in regard to Colstrip Units 1 and 2.

Comment: EarthJustice stated that EPA overestimated the cost of SCR.

Response: See our response to similar comment made by EarthJustice in regard to Colstrip Units 1 and 2.

Comment: EarthJustice claimed that the visibility benefit of SCR on Units 3 and 4 is substantial and therefore SCR should be required. EarthJustice noted that EPA modeled visibility benefits of SNCR and SCR and found a visibility benefit of 0.273 dv per unit from application of SCR. EarthJustice stated that application of SCR at both units would approximately halve the units' emissions of visibility impairing pollutants and would reduce the number of days of visibility impairment at Theodore Roosevelt NP to just 2 days and would eliminate visibility impairment caused by Units 3 and 4 at four other Class I areas. EarthJustice stated that, in light of this, we lacked a basis for our determination to not impose SCR at Colstrip Units 3 and 4. EarthJustice noted that, in North Dakota, we imposed LNB on two units at Antelope Valley Station based on a combined visibility benefit of 0.39 deciview, which we stated was significant even on a unit-by-unit basis of 0.2 deciview.

Response: We disagree that SCR should be required based solely on the modeled visibility benefits. As we explained in our proposal, we considered the four factors and the modeled visibility benefits of controls and determined that no additional controls should be required for this planning period. 77 FR 24066. Also, we stated that specifically, for SCR, the modeled visibility benefits (0.273 deciview and 0.260 deciview) were not sufficient for us to consider it reasonable to impose SCR in this planning period. 77 FR 24066. In making this determination, we noted that SCR was the more expensive option ($4,574/ton at Unit 3 and $4,607/ton at Unit 4). The cost of compliance is one of the four statutory factors, and EarthJustice has not provided a reason why it should be ignored. For the same reason, we reject the comparison with our North Dakota action. There, the cost-effectiveness of LNB at Antelope Valley Station was $586/ton for Unit 1 and $661/ton at Unit 2. 76 FR 58631. We explicitly considered these costs in making our determination to impose LNB. Here, the cost-effectiveness of SCR at Colstrip Units 3 and 4 is far above the cost-effectiveness of LNB at Antelope Valley Units 1 and 2. Thus, the comparison gives us no basis to change our determination that SCR should not be required in this planning period.

Comment: EarthJustice stated that EPA should set more stringent SO_2 emission limits at Colstrip Units 3 and 4 to help achieve reasonable progress. EarthJustice stated that EPA incorrectly found that no additional upgrades are feasible and that 98% SO_2 removal to meet an SO_2 emission limit of 0.05 lb/MMBtu at Units 3 and 4, which is readily achievable at little expense using MEL.

Response: EarthJustice cites a 1984 paper presented at the American Power Conference to support their argument of a lower emission rate. Colstrip 3 had only started operation in 1984 and Colstrip 4 did not commence operation until 1986,[63] the data cited by EarthJustice cannot be more than short-term tests of Unit 3 that are not representative of longer term performance. Annual emissions from 1985 and 1990 emissions from CAMD can be found in the docket. At the time these scrubbers were built, wet MEL scrubbers and wet caustic scrubbers were the only scrubbers that could deliver high capture rates (over 90%) with reasonable reliability. Scrubber technology has improved and other, less expensive, reagents are now preferred. Although Colstrip Units 3 & 4 used MEL in the past, MEL is not readily available in the region near the Colstrip plant. MEL is produced from a blending of dolomitic lime with high calcium lime to achieve a lime with a magnesium content of 3–6% or so. The lime is produced by calcination of limestone. Dolomitic limestone is limestone with a significant amount of dolomite, or calcium magnesium carbonate. Because there are no dolomitic limestone deposits near the Colstrip plant, the dolomitic lime must be sourced from remote locations. This increases the cost of the lime (that is made from the dolomitic limestone). According to Carmeuse, a supplier of MEL, the closest source of dolomitic lime is 1,000 miles away from the Colstrip plant and transportation would cost $0.12 per mile per short ton plus a 24% fuel surcharge to transport,[64] or close to $150/short ton just for transportation of the reagent. Because the lime would be blended in closer to the plant with high calcium lime at perhaps an 8:1 ratio (reducing magnesium content from about 40% to about 4–5% this would result in an increased reagent cost of $15–$20 per ton. Assuming a high-calcium lime cost of about $95/ton,[65] this raises the cost of reagent by close to 20% assuming constant reduction. Reagent use might be improved somewhat for a given reduction level, but considering this is a unique scrubber design, it is difficult to assess what the impact may be. Regardless, reliance on a reagent source that is 1,000 miles away may cause operating risks during the winter months if delivery was interrupted.

We also note that EarthJustice did not provide site-specific cost information, for us to evaluate MEL. The cost of compliance is one of the factors required to be considered by CAA section 169A(g)(1) and 40 CFR 51.308(d)(1)(i)(A). Based on all four factors, we continue to find that the level of performance of the current SO_2 removal system for Colstrip Units 3 and 4 is satisfactory for this planning cycle. We will re-evaluate additional SO_2 controls for Colstrip Units 3 and 4 in the next planning cycle.

Comment: PPL stated that EPA properly concluded that RPGs do not require additional emissions controls on Colstrip Units 3 and 4 and that existing emissions controls at Units 3 and 4 already limit emissions to levels below the presumptive BART limit. PPL stated that EPA's RP conclusion should not be affected by EPA's ultimate determination with respect to BART requirements for Colstrip Units 1 and 2 and that no further controls are warranted based on conclusions regarding the extent of existing emissions controls and the cost-ineffectiveness of further controls.

Response: PPL did not provide specific information for us to consider in making a change to our FIP. In any case, we have not required additional controls for Colstrip Units 3 and 4 in our final FIP.

K. Comments on Devon Energy

Comment: MDEQ stated that we failed to provide information or analysis of any visibility benefit that would result from the application of NSCR for Devon Energy. MDEQ suggested that we must consider visibility benefits as part of the Devon Energy reasonable progress analysis, as the BART Guidelines include evaluation of visibility impacts ''which would also appear to be required under the reasonable progress guidelines.''

Response: The four reasonable progress factors are the costs of compliance, the time necessary for compliance, the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources CAA section 169A(g)(1) and 40 CFR 51.308(d)(1)(i)(A). Our Reasonable Progress Guidance states: ''In determining reasonable progress, CAA section 169A(g)(1) requires States to take into consideration a number of factors. However, you have flexibility in how to take into consideration these statutory factors and any other factors that you have determined to be relevant.''[66] As stated in our proposal at 77 FR 24069, for Devon, we considered Q/D and potential reductions in Q/D, which are relevant to the goal of the Regional Haze Rule, improving visibility.

Comment: MDEQ commented that EPA should review the NO_X limit for Devon with respect to its averaging time and compliance determining method for practical enforceability.

Response: In the final FIP, we have made changes to the language in 40 CFR 52.1396 to clarify the requirements for Devon Energy.

L. Comments on Montana-Dakota Utilities

Comment: Montana-Dakota Utilities (MDU) commented that the company did not disagree with our Reasonable Progress determination. MDU stated that, for EPA's reference, paragraph 3 on page 1 of the Sargent & Lundy IPM model method document cautions as follows with respect to the application of the model to smaller units:

> The costs for retrofitting a plant smaller than 100 MW increase rapidly due to the economy of size. The older units which comprise a large proportion of the plants in this range generally have more compact sites with very short flue gas ducts running from the boiler house to the chimney. Because of the limited space, the SCR reactor and new duct work can be expensive to design and install. Additionally, the plants might not have enough margins in the fans to overcome the pressure drop due to the duct work configuration and SCR reactor and therefore new fans may be required.

MDU stated that Lewis & Clark Station is a small, 52 MW net capacity unit. In addition, MDU believes that the fan margin is not present at Lewis & Clark Unit 1 to overcome the pressure drop as discussed in the Sargent & Lundy guidance.

Response: MDU has not provided the information that would be necessary for

[63] See EIA Form 860 data.

[64] Email from Bob Roden, Carmeuse, to Jim Staudt, Andover Technologies, July 31, 2012.

[65] Sargent & Lundy, ''IPM Model—Revisions to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology FINAL'', Prepared for US EPA, August 2010 see table 2.

[66] Reasonable Progress Guidance, p. 5–1.

us to determine whether or not to agree with the implied point of this comment, which seems to be that EPA underestimated the cost of SCR. First, MDU has not indicated whether there are, in fact, space limitations at Lewis & Clark Station that would cause installation of an SCR reactor and associated ductwork to be more expensive than the cost estimate in our analysis. Second, MDU has not indicated whether the additional pressure drop from installation of SCR at Lewis & Clark Station would, in fact, require installation of new fans, and if so, whether or not our cost analysis failed to factor in the cost of new fans.

Comment: MDU indicated that EPA uses a Retrofit Factor value of 1 for Lewis & Clark Station Unit 1 in the IPM Model calculation (factor B in the EPA cost sheets) which indicates an average retrofit cost, however, a higher value would be expected for Lewis & Clark since it is a small facility (as discussed/cautioned above by Sargent & Lundy) and could be difficult to retrofit. A more appropriate value between 1.3 and 2.0 is therefore recommended.

Response: We disagree. MDU has not provided any data or information to substantiate that a retrofit factor other than 1 is warranted for Lewis & Clark Station. The IPM capital cost calculations for retrofits already account for unit size. We note that capital cost does not vary linearly with size in IPM. Instead, in the capital cost formula in IPM, the cost varies exponentially with unit size (a least squares fit). The IPM document states, ''The least squares curve fit was based upon an average of the SCR retrofit projects.'' IPM Model—Revisions to Cost and Performance for APC Technologies, SCR Cost Development Methodology, Final, Sargent & Lundy, August 2010, Chapter 5, Appendix 5–2A, page 4–5.

We also disagree with the statement that a more appropriate retrofit factor should be 1.3 to 2.0. The aforementioned IPM document states that, ''Retrofit difficulties associated with an SCR may result in capital cost increases of 30 to 50% over the base model.'' Therefore, the highest retrofit factor that might be considered would be 1.5.

This comment has not resulted in any change to our FIP proposal or to our cost calculations for SCR.

Comment: MDU stated that the model ''Type of Coal'' input indicates ''PRB'', but should be ''Lig,'' since Lewis & Clark burns lignite coal. That stated, the ''Coal Factor'' value in the cell below ''Type of Coal'' indicates lignite coal was actually considered. As such, this recommendation is clerical in nature.

Response: As shown in the ''Given/Assumptions'' spreadsheet in our SCR cost analysis, we used a heating value of 6,714 Btu/lb, which we considered to be representative of lignite coal. PRB coal would have a much higher heating value.

Comment: MDU stated that EPA used a NO_X input emission rate to the SCR of 0.26 lb/MMBtu, which is the low load emissions rate of low NO_X burners (LNB) and Separated Overfire Air (SOFA) that MDU estimated in Table C.2–1 of Appendix C.2 of the Emissions Control Analysis for Lewis & Clark Station Unit 1. The 0.25 lb/MMBtu for LNB/SOFA at high load is a more appropriate rate to use as the inlet to an SCR. While this does not result in a significant change to the overall conclusions in the report, it is nonetheless important because the EPA-derived cost was based on full load operation, as opposed to lower load.

Response: We disagree with the statement that we obtained the emission rate of 0.26 lb/MMBtu from the low-load scenario presented in Table C.2–1 of Appendix C.2 of MDU's Emissions Control Analysis. Instead, as indicated in the ''Given/Assumptions'' spreadsheet of our SCR cost analysis, we obtained the rate of 0.26 lb/MMBtu from Table C.2–6 of MDU's analysis. Table C.2–6 is not identified by MDU as a low-load scenario.

Comment: MDU stated that, from the IPM model guidance, EPA did not include factors N through V in the model calculations for operating costs for Lewis & Clark Station's evaluations. Although factors N through R and T through V are utility costs that were not needed in EPA's evaluation, the catalyst cost (factor S) was applied based on an alternative source. EPA references ''Cichanowicz (Jan 2010)'' with a cost of $170/ft³ as compared to the IPM value of $8,000/m³ ($226.53/ft³ in 2009$) and MDU's value of $214.29/ft³. MDU recognized that a range of potential costs exist, and believes that either the IPM value or the value MDU provided would be more appropriate for EPA to use since they are based on industry and vendor data respectively and are expected to represent a more site specific value as opposed to a literature based value.

Response: We disagree. The Cichanowicz document we used provided actual catalyst costs observed over time. It demonstrates that catalyst costs continue to decline. In fact, based on the trend displayed in the graph on page 6–6 of the document, it is likely that catalyst costs in upcoming years will be even lower than the $6,000/m³ assumed in our FIP proposal. Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies, J. Edward Cichanowicz, Prepared for Utility Air Regulatory Group, January 2010, page 6–6, Figure 6–6. This comment has not resulted in any change to our FIP proposal or to our cost calculations for SCR.

Comment: Similarly, to item e above, MDU noted that the cost EPA associated with aqueous ammonia ($0.12/lb) is lower than the cost MDU estimated of $0.70/lb. MDU recognized that a range of ammonia costs exists, that the price of ammonia fluctuates over time, and that the price is related to natural gas prices. As such, if SCR were to be considered in the future, MDU would ask that site specific, local, as delivered cost be evaluated at that time.

Response: We disagree. In its own SCR cost spreadsheet, MDU did not indicate the basis for its estimate of $0.70/lb. We used $0.12/lb based on data provided to us by control technology vendors on cost of aqueous ammonia. This comment has not resulted in any change to our FIP proposal or to our cost calculations for SCR.

Comment: MDU stated that, through the FR correction, EPA changed the language on 77 FR 24071 to state that an 85% control efficiency was used instead of the initially quoted 95% control efficiency for SDA and baghouse. MDU believes this correction was in error. Table 172 in the FR lists the control efficiency as 85% for SDA and baghouse and this value should be corrected to 95% control efficiency for SDA and baghouse as the textual representation in the FR was correct.

Response: We disagree. We made the correction from 95% to 85% because MDU's Emissions Control Analysis dated June 2011, at Table 1 on page 14, shows an expected SO_2 emission reduction of 850.3 tons per year, for SDA with baghouse. The baseline SO_2 emissions listed in the table are 1,002.1 tons per year. This amount of reduction represents 85% control efficiency. We presented these figures at 77 FR 24071, Table 172. MDU later wrote to us on February 10, 2012, to say that 70–90% control is the generally anticipated range of SO_2 control for this control option, and that 95% control was also assumed and represented a screening level assumption for a high degree of SO_2 control. In its February 10, 2012 submittal, MDU did *not* indicate that Table 1 of their June 2011 submittal should be revised, so we used the figures presented in MDU's Table 1.

Comment: In Table 172 of the proposed FIP (77 FR 24071), EPA provides a 10% control effectiveness for both DSI with baghouse and existing scrubber mod; however, MDU stated that this value should be changed to 70% to reflect the overall reduction and not the incremental reduction as shown in Table 1 of MDU's Emissions Control Analysis for Lewis & Clark Station Unit 1.

Response: We disagree. We stated that we did use 70% overall SO_2 control effectiveness for DSI with baghouse, as well as for existing scrubber mod, in our analysis. 77 FR 24071. However, we also stated that existing SO_2 controls at Lewis & Clark Station, consisting of a flooded disc wet scrubber, have achieved up to 60% control under certain operating conditions. 77 FR 24070. We obtained this information from MDU's analyses. 77 FR 24070, footnote 265. MDU's Emissions Control Analysis dated June 2011, at Table 1 on page 14, lists an expected emissions reduction of 100.2 tons per year for DSI with baghouse, and the same amount of reduction for existing scrubber mod. This is a 10% reduction from the baseline emissions of 1,002.1 tons per year listed in that table. We relied on these figures from MDU in listing a control effectiveness of 10% for DSI with baghouse, as well as a control effectiveness of 10% for existing scrubber mod. For all control options analyzed in our FIP proposal, we present control effectiveness in terms of the reduction that might be achieved from baseline emissions. In this case, the baseline emissions already reflected a 60% level of SO_2 control.

Comment: EarthJustice argued that EPA should require Lewis and Clark to switch from lignite fuel to natural gas as a reasonable progress measure. The unit already uses natural gas for startup, there is a natural gas supply close by, and thus switching to natural gas is, in commenter's view, quite feasible and cost effective for Lewis and Clark station. Switching to natural gas should be required in the FIP to help achieve reasonable progress, as this measure would virtually eliminate the unit's SO_2 and PM emissions and would also reduce NO_X emissions. Although EPA dismissed fuel switching as not cost effective, commenter argues that EPA vastly understated the cost effectiveness of this measure.

Commenter first stated that EPA has overstated the costs of switching to natural gas, in large part because it has underestimated, and in some cases ignored, the tremendous cost savings that would result from not operating the facility's scrubber, multi-cyclone dust collector, and coal preparation systems. EPA also relied on inflated estimates for natural gas and natural gas supply pipelines provided by MDU, which owns Lewis and Clark.

Commenter also stated that EPA has improperly calculated the emissions reductions achievable from fuel switching. EPA failed to take into account the fact that the use of natural gas would replace the existing SO_2 and PM controls. Commenter stated that, in view of the 54 kilometer distance from Lewis and Clark to the closest Class I area, filterable PM must be considered. Thus, EPA should have accounted for the pollution reductions that would be achieved with natural gas from uncontrolled levels of SO_2 and PM. Properly calculated, fuel switching would eliminate 24,000 tons per year of SO_2, NO_X and filterable PM. As EPA noted, Lewis and Clark's remaining emissions would be ''negligible.''

Commenter concluded that, even using EPA's inflated cost estimate, when uncontrolled rates of SO_2 and PM are used as the baseline, the cost effectiveness of switching to natural gas at Lewis and Clark station is $909/ton of SO_2, NO_X and PM removed. This measure is highly cost effective and should be required to help achieve reasonable progress.

Response: We disagree. Although we do not believe it was necessarily an error for us to rely on MDU's estimate of the price of natural gas, we acknowledge that price estimates for natural gas can vary, and that the $3.07/Mscf price of natural gas cited on page 129 of the commenter's Technical Support Document, obtained from the Energy Information Administration (EIA), is substantially lower than MDU's estimate of $7.91/Mscf. However, even if we rely on the price cited by the commenter, the cost of a fuel switch would still be excessive. Using $3.07/Mscf, along with MDU's estimate of 3,282,876 Mscf of natural gas which would be needed to fuel Lewis and Clark station year-round solely on natural gas (not disputed by the commenter), we calculate the annual cost of natural gas at $10,078,429. MDU estimated the annual cost of coal at $5,754,732. The annual fuel cost differential would therefore be $4,324,197. To this result we add the annualized cost of constructing a natural gas pipeline ($1,699,200), as we did in our FIP proposal.[67] This yields a total annual cost of $6,023,397. Dividing this result by an expected SO_2 emission reduction of 1,002 tons per year yields cost effectiveness of $6,011/ton. Based on this cost and other factors for Lewis and Clark station described in our FIP proposal at 77 FR 24072, we would still eliminate fuel switching as a control option for SO_2.

We disagree with the statement that a fuel switch would yield ''tremendous'' cost savings from not operating the facility's scrubber, multi-cyclone dust collector, and coal preparation systems. Commenter has not quantified the cost savings. We have no reason to believe they would be ''tremendous.'' We believe the cost savings would be minimal in comparison to other components of our cost calculations for a fuel switch. The cost savings would likely consist primarily of avoidance of electricity and maintenance costs for the equipment cited by the commenter.

Also, we disagree with the statement that we should have calculated reductions from uncontrolled levels of SO_2 and PM. In every cost analysis of control options for our FIP, we calculate reductions from an emissions baseline which is the current actual annual emissions, consistent with the approach laid out in the 2005 Regional Haze Rule, at 70 FR 39167, for calculating cost effectiveness of control options. Commenter's citation to a 2008 letter sent by EPA in the course of developing initial information for a FIP ignores the basis for the action we actually proposed.

We also disagree with the statement that a ''proper cost analysis'' would result in cost-effectiveness of $909/ton. Commenter apparently calculated $909/ton based on reduction from uncontrolled emissions, for the sum of three pollutants (PM, SO_2 and NO_X). We have explained above why we do not use uncontrolled emissions as the baseline. We also explained in our proposal that, in our reasonable progress determinations, we were not evaluating controls for PM for potentially affected sources, based on our analysis of the emissions inventory and results from BART modeling. 77 FR 24055–56. Commenter has not disputed those bases; commenter merely notes the 54 kilometer distance to Theodore Roosevelt NP. Given these flaws, the commenter's cost analysis provides no basis for us to reconsider our decision.

Comment: Commenter noted that, although MDU proposed upgrades to its existing SO_2 and NO_X pollution controls, EPA failed even to require these measures to help achieve reasonable progress. See 77 FR 24074. Commenter stated that MDU's proposal is vastly inferior to fuel switching at reducing haze pollution, but MDU's

[67] Commenter's speculation that the existing pipeline could be upgraded does not provide sufficient basis for us to supplant MDU's estimated cost for a new pipeline with some other cost. We note that, even if the upgrade were feasible and had zero cost, the cost effectiveness of the SO_2 reductions would still be well over $4,000/ton.

proposed controls are the bare minimum that EPA should have required for reasonable progress.

Commenter noted that MDU proposed to improve SO_2 removal to 70% by optimizing the existing particulate scrubber and lime injection system with a proposed limit of 0.45 lb/MMBtu. EPA estimated the cost effectiveness of this modification at $1,383/ton SO_2 removed. MDU also proposed SOFA and low NO_X burners (upgraded) to achieve a NO_X emission rate of 0.25 lb/MMBtu. EPA estimated the cost effectiveness of this option as $1,213/ton of NO_X removed. Commenter stated that, although the emissions reductions from these measures are modest, they are highly cost effective and are the minimum that EPA should have required from Lewis and Clark to achieve reasonable progress.

Response: We disagree. MDU's proposal to improve SO_2 and NO_X emission control was contained in its June 2011 Emissions Control Analysis, which was submitted in response to a CAA section 114 information request from us. Under the Regional Haze Rule, we are not bound by controls that a source has proposed when we make our reasonable progress determination based on the four statutory factors.

With regard to the statement that cost-effectiveness of $1,383/ton for SO_2 and $1,213/ton for NO_X is ''highly cost-effective'' and should result in a requirement for emissions reductions, commenter has not provided a basis for this conclusion. As explained in our FIP proposal at 77 FR 24072 (for SO_2) and 24074 (for NO_X), in making our reasonable progress determination for Lewis and Clark Station, we considered the following four reasonable progress factors: cost of compliance, the time necessary for compliance; the energy and nonair quality environmental impacts of compliance; and the remaining useful life of the source. We also took into account the following additional factors: size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. Commenter has not disputed the appropriateness of using the four reasonable progress factors and other factors in our proposal.

Comment: WEG commented that the determination in the proposed rule that no additional SO_2 controls are required on Lewis & Clark Station is unreasonable. WEG notes that two highly effective control options are available (fuel switch to natural gas at 99% control effectiveness and SDA with baghouse at 85% control effectiveness) and should be further considered.

Response: We disagree. EPA did not evaluate control options for Regional Haze FIP development solely based on emission control effectiveness. As indicated in EPA's analysis, the cost of fuel switching is estimated at $21,875 per ton of pollutant removed and the cost of SDA with baghouse is estimated at $11,825 per ton of pollutant removed. 77 FR 24072, Table 173. EPA has already explained that this cost is excessive. WEG has not provided a reason to not consider the cost excessive. Besides the cost of compliance, EPA also explained that other factors were taken into consideration in determining whether additional SO_2 controls should be required at Lewis & Clark Station, those being the time necessary for compliance, the energy and nonair quality environmental impacts of compliance, the remaining useful life of the facility, the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. WEG did not provide a reason to re-evaluate these other factors.

Comment: WEG comments that EPA should re-examine its decision to eliminate all control options for NO_X and move to require HDSCR + SOFA/LNB at Lewis & Clark Station. WEG notes that this control option has a high control effectiveness of 87.5% and considers the cost of $4,853 per ton of pollutant removed to be reasonable. To rule it out alongside a fuel switch to natural gas, which has a much higher cost of $41,934 per ton of pollutant removed, lacks reason. WEG stated that the cost and visibility benefits of HDSCR + SOFA/LNB should be considered individually, and the control option should be implemented because of the great emissions reduction it achieves, and because the FIP is far from attaining a Uniform Rate of Progress (URP) akin to the regulatory rate. WEG also stated that the final analysis of control options took into account only ''the most cost effective option (SOFA/LNB)'' when weighing cost against overall reductions in emissions.

Response: We disagree. EPA did consider control options individually. At Step 5 of its NO_X analysis, EPA mentioned cost of HDSCR + SOFA/LNB in the same sentence as cost of a fuel switch only because those two options happened to be the most expensive. 77 FR 24074. Besides the cost of compliance, EPA also explained that other factors were taken into consideration in determining whether additional NO_X controls should be required at Lewis & Clark Station, those being the time necessary for compliance, the energy and nonair quality environmental impacts of compliance, the remaining useful life of the facility, the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. At Step 5, EPA explained how these factors were considered with respect to all control options, not just SOFA/LNB. In the case of HDSCR + SOFA/LNB, EPA explained that this control option was eliminated on the basis of not only cost, but also on the basis of the small size of the facility and the relatively small baseline Q/D of the facility. WEG has not provided a reason to re-evaluate these other factors. With regard to URP, that comment was addressed in a previous response.

M. Comments on Montana Sulphur and Chemical Company

Comment: MSCC commented that the company agrees with the conclusion in the proposed FIP that additional controls are not required at this time. MSCC also stated it does not believe we should have considered it to be a BART-eligible source. The company referenced several letters and discussions with MDEQ that were previously submitted and had as part of development of the regional haze plan for Montana.

Response: Because the commenter ultimately agrees with the final conclusion and controls are not required for MSCC, at this time, we find the comment to be non-substantive.

N. Comments on Health, Ecosystem Benefits, Other Pollutants, and Coal Ash

Comment: Several commenters stated that haze pollution significantly impacts human health and ecosystem health. Specifically, commenters asserted that haze pollution, including haze pollutants NO_X, SO_2 and PM, contributes to heart attacks, asthma attacks, chronic bronchitis and respiratory illness, decreased lung function, increased hospital admissions, and even premature death. Another commenter stated that NO_X and SO_2 can combine to create photochemical smog and ozone, which can exacerbate health problems.

Some commenters cited a 2010 Clean Air Task Force report in stating that the Colstrip coal-fired power plant put 31 people at risk of premature death, 48 people at risk of a heart attack, 47 people at risk of acute bronchitis, and 534 at risk of an asthma attack each year.[68] Several commenters encouraged EPA to finalize the regional haze proposal citing their own health

[68] Several commenters cited numbers that were similar to these, but did not match them exactly.

problems, or the health problems of family members.

Some commenters stated that the negative health impacts of this pollution disproportionately harm vulnerable populations, specifically the young and elderly, and that this disproportionate harm potentially makes this a case of environmental justice. A commenter claimed that Colstrip causes a dark shadow on snow and takes human lives. One commenter stated the rate of asthma in children in Rosebud County is the third highest of all counties in the State, while another stated the rate of birth abnormality in the area downwind of Colstrip is much higher (34%) than in most other counties in Montana (10%). One commenter stated that over 10% of Montana high school students were estimated to have asthma in 2009. A commenter surmised that a 50% reduction in pollution from Colstrip would help human health more than eliminating pollutants from all other Montana sources.

Some commenters expressed a willingness to pay more for power in support of pollution control technology, with others stating that we should all pay the full cost of energy and not pass it on as healthcare costs. Another commenter stated that the cost of pollution controls, especially at Colstrip, was small when compared to the health-related benefits. Other commenters stated that the sources should not be allowed to externalize the costs of their pollution onto the people, who must pay for them in the form of health-related costs.

Some commenters stated that haze pollution negatively impacts ecosystem health. Commenters expressed concern for the effects of haze pollution on plants and water bodies. Some commenters specifically expressed concern over acid deposition from SO_2 and NO_X emissions, which they argued can leach into drinking water sources and harm crops. One commenter attributed high levels of mercury in some Montana back country lakes to coal-fired power plant emissions.

Other commenters supported EPA's position that consideration of health benefits is not relevant under the regional haze program.

One commenter stated that we should regulate coal ash at Colstrip. Another commenter expressed concern about acid rain, and one commenter stated that various pollutants such as dioxin and formaldehyde were byproducts of coal pollution.

Response: We acknowledge the commenters' concerns regarding the negative health impacts of haze-causing emissions. We agree that the same $PM_{2.5}$ emissions that cause visibility impairment can cause respiratory problems, decreased lung function, aggravated asthma, bronchitis, and premature death. We also agree that the same NO_X emissions that cause visibility impairment also contribute to the formation of ground-level ozone, which has been linked with respiratory problems, aggravated asthma, and even permanent lung damage. We agree that these pollutants may have negative impacts on vegetation, and reduce crop yields. However, for purposes of this action, we are not authorized to consider these impacts in promulgating our FIP, and we have not done so. However, to the extent that this FIP will lead to reductions in these pollutants, there will be co-benefits for public health.

We recognize the importance of considering environmental justice; for this action, we are finalizing emission limitations that will result in emissions reductions that will benefit potential environmental justice communities. Therefore, this action will have no high adverse and disproportionate impact on potential environmental justice communities.

Mercury is not a visibility impairing pollutant, and was therefore not included in our analysis. We also are not authorized to regulate coal ash in this action.

Comment: Some commenters noted that regional haze is not a health-based standard, and that there are other recently enacted rules that protect human health.

Response: We agree that the Regional Haze Rule was not intended to address health concerns. Regional Haze is not a health-based standard.

O. General Comments Supporting Our Proposal or for Stricter Controls

Comment: NPCA and MATB commended EPA's required controls for the Ash Grove and Holcim cement kilns. The Northern Cheyenne Tribe expressed support of our proposal as a whole.

Response: We acknowledge the support provided by these commenters.

Comment: Overall, we received more than 47,000 comment letters from members representing various organizations and concerned citizens requesting that EPA mandate more stringent and effective controls, most notably SCR, on eligible Montana sources. These comments were received at the public hearings in Billings and Helena, Montana, by Internet, and through the mail. Many of these commenters argued that SCR is required at over 200 facilities in the U.S., and that SCR should therefore also be required at the coal-fired plants in Montana. A mass mailer from WEG claimed that SCR was shown to be cost-effective, but is not required. Several comments more generally stated that EPA should require the most modern, effective pollution controls on Montana sources, but did not specifically discuss the desired requirements. The Montana Conservation Voters pointed out that pollution from Colstrip will be three times higher than if SCR were required.

Response: Although we acknowledge the commenters' encouragement that we adopt even stricter standards, the standards discussed in our proposal are appropriate considering the costs and visibility improvement.

Comment: One commenter pointed out that Colstrip emits more pollutants than the nine next largest haze producers, combined.

Response: The commenter did not explain specifically what they were requesting.

Comment: A commenter pointed out that Colstrip 3 and 4 are as highly polluting as Colstrip 1 and 2, and thought that Colstrip 3 and 4 should also be required to install additional controls.

Response: As explained in our proposal, the modeled visibility benefits are not sufficient for us to consider it reasonable to impose additional controls for Colstrip units 3 and 4 for this planning period. 77 FR 24066 and 77 FR 24067.

Comment: One commenter stated that the upgrading of pollution controls on coal-burning facilities also helps mitigate the effects of climate change. A separate commenter requested that EPA's plan consider CO_2 because of its impacts on climate change, while another stated that coal should no longer be burned, as such action would slow global climate change.

Response: While we understand the commenters' concerns with respect to climate change, consideration of climate change is outside the scope of this action. CO_2 is a greenhouse gas (GHG) and is not considered a visibility impairing pollutant. However, EPA implements regulations that address GHGs in order to protect the public and the environment from the negative impacts of climate change.

P. General Comments That the Proposal Is Too Stringent

Comment: Various commenters generally stated they did not support the proposed rulemaking. Their reasons included: It will negatively affect the local economy; it will negatively affect the coal power plant industry; electricity costs will increase; health concerns are exaggerated; direct and indirect jobs/businesses would be adversely affected; the costs outweigh the benefits; Colstrip is already significantly regulated; there are no air quality issues in Colstrip; and it will not result in noticeable visibility improvements. One commenter insisted our proposal is part of a broader anti-coal plan to shut down coal plants, while another stated that Congress should legislate national energy policy rather than involving federal agencies. One commenter stated that PPL is very committed to clean air and environmental stewardship and another stated that Colstrip is already heavily regulated and additional controls are unnecessary. One commenter stated that mismanagement of forests causes more haze and that Colstrip provides good jobs and has a good compliance record.

Response: We acknowledge these general comments that opposed our proposed action as being too stringent. We provide responses that address some of these issues elsewhere in this action. This action is based on the statutory and regulatory requirements for regional haze which we have followed.

Q. General Comments on Visibility Improvement and Other Causes of Haze

Comment: Some commenters stated that any controls required by our action must demonstrate a perceptible visibility improvement and some stated that the reductions in the proposal will not produce perceptible visibility improvement. Other commenters said that there were no haze issues in Montana and that the change in visibility is subjective. The Montana Chamber of Commerce commented that our FIP is not based on sound science, accurate measures, or proven measures that will solve the problem.

Some commenters stated that gravel roads and forest fire are the real causes of haze.[69] WETA commented that under the FIP, haze would not be effectively reduced and EPA's regional haze plan should consider all established sources of emissions and not just industrial facilities. Another commenter suggested that money to clean up pollution should be spent in urban areas where there are real problems, not in rural areas like Montana. An individual submitted information comparing Montana emissions from different sources.

One commenter noted that the proposed rule delays, by hundreds of years, in some cases, achievement of the 2064 natural visibility goal. Numerous commenters stated that EPA should not forego cost-effective pollution controls when more progress is clearly needed to protect air quality. Some commenters stated that there is currently haze at Yellowstone that was not visible years ago.

With regard to Colstrip, a commenter said that shutting down Colstrip would not clear the haze and that areas outside Montana, including Oregon, Washington, and China influence the haze at Yellowstone. Another commenter stated that there is no haze in the town of Colstrip and that the wind does not blow in the directions of Yellowstone and Roosevelt.

Response: We disagree that any controls required by our action must demonstrate a perceptible visibility improvement. In a situation where the installation of BART may not result in a perceptible improvement in visibility, the visibility benefit may still be significant. The Regional Haze Rule states ''even though the visibility improvement from an individual source may not be perceptible, it should still be considered in setting BART because the contribution to haze may be significant relative to other source contributions in the Class I area. Failing to consider less-than-perceptible contributions to visibility impairment would ignore the CAA's intent to have BART requirements apply to sources that contribute to, as well as cause, such impairment.'' 70 FR 39129. Visibility impacts below the thresholds of perceptibility cannot be ignored because regional haze is produced by a multitude of sources and activities which are located across a broad geographic area.

We agree that industrial facilities are not the only causes of haze. Our action considered the many contributors to haze including industrial facilities. In this action, we also proposed changes to Montana's Visibility SIP that would require BACT for open burning.

Even though some Class I areas will not attain natural visibility conditions by 2064, our action requires the controls that were determined to be effective according to our evaluation. For those sources subject to BART, we evaluated: (1) Cost of compliance, (2) the energy and nonair quality environmental impacts of compliance, (3) any existing pollution control technology in use at the source, (4) remaining useful life of source, and (5) degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology and we determined which controls should be required according to that evaluation. In determining the measures necessary to make reasonable progress and in selecting RPGs for mandatory Class I areas within Montana, we took into account the following four factors: (1) Costs of compliance, (2) time necessary for compliance, (3) Energy and nonair quality environmental impacts of compliance; and (4) remaining useful life of any potentially affected sources. CAA section 169A(g)(1) and 40 CFR 51.308(d)(1)(i)(A).

For Colstrip, we evaluated visibility improvement at all Class I areas within 300 km. As stated above we evaluated other sources of haze, including but not limited to, gravel roads and forest fires. The most impacted Class I areas were Theodore Roosevelt NP and UL Bend WA. While sources outside Montana do contribute to haze in the Class I areas within Montana, that does not preclude our obligation to evaluate Colstrip Units 1 and 2 according to the five BART factors and to evaluate Colstrip Units 3 and 4 according to the four reasonable progress factors and to require additional controls where necessary.

R. Comments on Cost, Economic Impact, Jobs and Price to Consumers

Comment: Some commenters stated that the proposed rule would have a negative economic impact and a negative impact on job creation and growth. Some commenters stated that PPL might shut down Colstrip Units 1 and 2 as a result of this action. One commenter explained that shutting down power plants removes jobs, and prevents other businesses from using the energy from the power plant, causing a domino effect. A commenter submitted documents describing Colstrip's positive economic and community impact. Another commenter said that specifically, Montana has a large percentage of low income and senior citizens who would be majorly burdened by an increase in utility cost and another commenter said that the cost would also be very burdensome for the small business community in the area. The Southeastern Montana Development Corporation stated that the economic impact of this action would be devastating to consumers. One commenter said that the costs were prohibitively expensive and another said that the costs could put the plants at risk for future investments due to lack of economic viability. A commenter suggested that the initial cost of investment at Colstrip 1 and 2, including the cost of debt and capital, would be in excess of $82 million and that the capital cost, plus operating cost of $377 million could result in a 19.6% increase in the cost of production. Another commenter suggested that the cost of electricity could increase by a

[69] One commenter also mentioned idling trucks, oil refineries and farms as causes of haze.

factor of 20 in 3–4 years. One commenter urged us to consider the indirect ways that controls on Colstrip 3 & 4 could affect electric rates. Numerous commenters stated that the reason EPA was not requiring SCR was to save polluters money.

Other commenters said that the health costs of pollution and economic benefit from tourism should be considered. One commenter said that the health related costs from Colstrip are estimated to be $230 million annually. Another commenter stated that air pollution controls are cost effective based on an EPA report. One commenter said that pollution hinders the Billings economy because the city's economic vitality is linked to high quality life-styles, while another noted that haze diminishes tourists' scenic vistas.

Some commenters pointed out that the proposed rule would create jobs. One commenter stated that complying with the rule would create good, high-paying jobs for Montana's skilled work force, including boilermakers, laborers and pipefitters. Numerous commenters stated that nearly 1,000 full-time jobs could be created at Colstrip from installing pollution control equipment. One commenter said that the Colstrip plant will not shut down just because added technology is required.

Many commenters expressed a willingness to pay more for power in support of pollution control technology. Others similarly stated that we should all pay the full cost of energy and not pass it on to healthcare. Some commenters stated that they thought PPL could afford to pay for additional controls based on the company's profit. A report submitted by Power Consulting, Inc. found that the typical residential customer's bill would increase by 55 to 89 cents if SCR were required on Colstrip unit 4. The overall conclusion from that report was that the impact of a required SCR retrofit on customer's rates would be small enough that it would not disrupt household budgets nor cause a significant impact on the Montana economy.

Response: EPA's evaluation of capital and annual expenses associated with implementation of the FIP shows such expenses to be justified by the degree of improvement in visibility in relationship to the cost of implementation. BART requires that we evaluate: (1) Cost of compliance, (2) the energy and nonair quality environmental impacts of compliance, (3) any existing pollution control technology in use at the source, (4) remaining useful life of source, and (5) degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. In determining the measures necessary to make reasonable progress and in selecting reasonable progress goals for mandatory Class I areas within Montana, we must take into account the following four factors: (1) Costs of compliance, (2) time necessary for compliance, (3) Energy and nonair quality environmental impacts of compliance; and (4) remaining useful life of any potentially affected sources. CAA section 169A(g)(1) and 40 CFR 51.308(d)(1)(i)(A). The cost of electricity to consumers and the overall impact on the economy is outside the scope of our evaluation for this action.

Although we did not consider the potential positive benefits to local economies in making our decision, we do expect that improved visibility would have a positive impact on tourism-dependent local economies. Also, the retrofits required are large construction projects that will take up to five years to complete. These projects will require well-paid, skilled labor which can potentially be drawn from the local area and support local growth.

Comment: A commenter stated that EPA should have included, as associated per-unit costs, consideration of the ''wider market consequences'' of a potential shutdown of generating capacity at Colstrip 1 and 2. The commenter says that, ''[i]f the cost of production resulting from this rule * * * exceeds the market value of power, PPL may make a decision to shutter the plant.'' The commenter also states that, ''[b]ased on an analysis of production cost data, there is at least some chance that Colstrip Units 1 and 2 would become uneconomical as a result of mandated upgrades.'' Specifically, commenter estimated that the ''all-in'' cost of production of electricity post-controls is $25.591 per megawatt-hour, a 19.6% increase over the current $21.40 per megawatt-hour cost of production reported in Federal Regulatory Commission filings. Commenter stated that, compared to current market prices from a regional trade publication,[70] Colstrip 1 and 2 would often be uneconomical at that estimated cost.

The commenter also argued that a closure at Colstrip 1 and 2 would decrease available electrical generation in the northwestern U.S. The commenter stated that we wrongly failed to consider these factors of potential plant closure and the subsequent constriction of power supply in our analyses.

Response: Analyzing the wider market consequences of a potential shutdown of generating capacity at Colstrip 1 and 2 involves many complicated factors and it is unclear from the information provided by the commenter that Colstrip Units 1 and 2 would, in fact, shut down. As noted previously, we have received conflicting information regarding potential rate increases. Specifically, a report submitted by Power Consulting, Inc. found that the typical residential customer's bill would increase by 55 to 89 cents if SCR were required on Colstrip unit 4. The BART Guidelines allow for the consideration of unusual circumstances that justify taking into consideration the conditions of the plant and the economic effects of requiring the use of a given control technology. The BART Guidelines state:

> [t]hese effects would include effects on product prices, the market share, and profitability of the source. Where there are such unusual circumstances that are judged to affect plant operations, you may take into consideration the conditions of the plant and the economic effects of requiring the use of a control technology. Where these effects are judged to have a severe impact on plant operations you may consider them in the selection process, but you may wish to provide an economic analysis that demonstrates, in sufficient detail for public review, the specific economic effects, parameters, and reasoning.

70 FR 39171. The commenter has not provided any basis that unusual circumstances exist here. Nor has the commenter providing any information that indicates a shutdown will occur that we could have taken into account in our analysis. The owners of Colstrip Units 1 and 2 have made no indication that there are unusual circumstances present that warrant taking wider market consequences into consideration.

S. Comments About Other Forms of Energy

Comment: We received comments regarding alternative forms of energy. Some commenters believed that wind energy would create more jobs while others believed that it would not create as many jobs compared to coal fired power plants. Some commenters stated that wind energy was cheaper to produce while one commenter pointed out that the government subsidizes wind energy. One commenter believed that the wind farm in Judith Gap produces energy more cheaply compared to the Colstrip coal plant. One commenter stated that our energy

[70] Commenter cited the trade publication ''Clearing Up,'' which commenter stated reports on prices at the Mid-Columbia trading club.

should be focused on renewable sources rather than coal and another commenter stated that the most important thing we can do to slow global warming is to stop burning coal.

Response: While we do generally acknowledge that many kinds of renewable energy do not produce haze-causing pollutants, and transitioning to those sources of energy could lead to visibility improvements. In this action we are required to review specific retrofit options for specific sources subject to BART or the sources analyzed under reasonable progress. Renewable energy technology is not a retrofit option for these sources and is outside the scope of our determinations and regulatory requirements in this action.

T. Other Miscellaneous Comments

Comment: One commenter asked whether EPA was concerned that requiring these facilities to install emissions control equipment to address fine particles and precursors might impact the effectiveness of equipment installed to address other pollutants.

Response: The control technologies that are required will not negatively impact the effectiveness of equipment installed to address other pollutants.

Comment: One commenter asked whether the agency was concerned that the technologies prescribed to address particles and precursors might also impact the efficiency and reliability of kilns, boilers, generators and other essential equipment.

Response: The control technologies required will not negatively impact the efficiency and reliability of kilns, boilers, generators and other essential equipment. As required under BART, we evaluated the energy impacts for each control option considered. 70 FR 39168 and 70 FR 39169. These impacts are discussed in the relevant sections of the proposed rule and in all cases are minor. In addition, as required under BART, we evaluated the technical feasibility for each control option considered. Where we have selected additional controls, the controls are shown to be technically feasible at similar facilities. Issues associated with the reliability of the emission units, if any, are resolvable.

Comment: MDEQ requested that EPA extend the comment period to sixty days from the date of the publication of corrections, or July 16, 2012.

Response: The comment period for our proposal closed on June 19, 2012. We carefully considered the request for an extension to the comment period. We took into consideration how an extension might affect our ability to consider comments received on the proposed action and still comply with our consent decree deadlines. We do note that our May 1, 2012, public hearing in Helena, Montana and May 2, 2012, public hearing in Billings, Montana were well attended and provided an opportunity for people to comment on our proposal. We also note that the corrections published May 17, 2012, (77 FR 29270) primarily amended typographical errors.[71]

Comment: MDEQ suggested that EPA issue a request for additional comment to clarify the scope of the proposed FIP. MDEQ asserted that such a clarification is necessary to prevent confusion among the public regarding the Regional Haze Rule's prevention and correction of adverse health effects, about which EPA received multiple comments. MDEQ warned that ''the level of this misperception threatens to pervert not only the National Goal, but, ostensibly, the public health goals of Section 110.''

Response: We do not agree that the scope of the proposed FIP requires clarification. At no point in the proposed FIP did we discuss public health impacts as a consideration in our analyses, as they were not. As stated elsewhere, we agree that the Regional Haze Rule is not a health-based standard, and that we are not authorized to consider public health impacts in promulgating our FIP for purposes of this action. However, we have not been presented any information from the public to indicate that there is confusion that that reduction of visibility impairing pollutants also provides health benefits.

Comment: One commenter stated that the Cheyenne Reservation was given Class I air quality designation and that according to that designation there is not supposed to be any degradation of that air.

Response: The Regional Haze Rule requires analysis for the 156 mandatory Class I areas listed at 40 CFR Part 81. The Cheyenne Reservation is not one of these federally mandated Class I areas.

Comment: WEG stated that EPA overlooked, in two respects, the requirement of section 110(l) of the Act to prevent interference with attainment or maintenance of the NAAQS. First, WEG stated that EPA has not demonstrated that this FIP adequately safeguards the 2006 $PM_{2.5}$ NAAQS, the 2008 ozone NAAQS, the 2010 1-hour NO_2 NAAQS, and the 2010 1-hour SO_2 NAAQS. In particular, WEG noted that the FIP emissions limitations are generally expressed as 30-day rolling averages, which, in WEG's view, do not adequately protect short-term NAAQS such as the 2010 1-hour SO_2 and NO_2. Second, WEG argued that several BART emissions limitations are relaxations that may impact the NAAQS. As an example, WEG cited another portion of its comments in which WEG argued that the BART emissions limitations for Corette will allow actual emissions from Corette to increase. WEG concluded that EPA must conduct a 110(l) demonstration in order to protect public health and not interfere with maintenance and attainment of the NAAQS.

Response: EPA disagrees with WEG. In relevant part, section 110(l) provides that EPA shall not approve a revision of a plan if the revision would interfere with any applicable requirement concerning attainment and reasonable further progress or any other applicable requirement of the CAA. First, WEG does not explain how section 110(l) applies to EPA's initial promulgation of a FIP for certain regional haze requirements when there is no existing SIP to meet those requirements. Second, to the extent that section 110(l) applies, EPA's promulgation of this FIP satisfies its requirements. It is EPA's consistent interpretation of section 110(l) that a SIP revision does not interfere with attainment and maintenance of the NAAQS if the revision at least preserves the status quo air quality by not relaxing or removing any existing emissions limitation or other SIP requirement. EPA does not believe that a full attainment or maintenance demonstration for each NAAQS is required for every SIP revision under section 110(l).

In this case, the FIP imposes new emissions limitations on a number of existing sources, and it does not relax any existing emissions limitations or other SIP requirements. WEG's statement that actual emissions at Corette and other BART sources might rise to the BART limit misses the point: In the absence of the BART limit (or any other limit), those actual emissions could increase much more. In other words, imposing an emissions limitation where one did not exist before is necessarily a more stringent requirement, regardless of actual emissions. Nor does WEG explicitly identify any existing emissions limitation or other SIP requirement that is relaxed by the FIP. For that matter, nothing in the proposal, or in the preamble or regulatory text for this rule, purports to modify any existing SIP-approved emissions limitation or other SIP requirement. Thus, even if there were such a requirement—and WEG has identified none—it would not be

[71] We corrected some technical information in the Holcim SO_2 BART analysis. See 77 FR 29270.

relaxed by this FIP. EPA therefore concludes that, to the extent that section 110(l) is applicable to this FIP, its requirements are satisfied.

Comment: Commenter stated that the input of Montana residents should be given more weight than the input of special interest groups that receive support from outside the State. Commenter also requested that future hearings be held in areas of impact.

Response: Any commenter who submits a comment on the proposed FIP, either orally or written, during the public comment period is entitled to do so. EPA takes all comments into consideration in making its final decision on the FIP. If future hearings are required for any reason, we will do the best we can to ensure access is available to all those who wish to participate.

V. Changes From Proposed Rule and Reasons for the Changes

A. Emission Limits for Corette

We proposed a PM emission limit of 0.10 lb/MMBtu for Corette at 40 CFR 52.1396(c). We inadvertently stated that we were imposing an emission limit of 0.10 lb/MMBtu in the preamble to our proposed FIP (77 FR 24047) and also at 40 CFR 53.1396(c)(1). PPL commented that the emission limit in the proposed FIP was flawed and PPL provided additional information indicating that over the past five years, stack test results have shown that PM emissions have ranged from 0.059 lb/MMBtu to 0.252 lb/MMBtu. We have changed the emission limit in the final regulatory requirements at 40 CFR 1396(c)(1). In the final FIP, we are establishing a PM emission limit of 0.26 lb/MMBtu.

We proposed a SO_2 emission limit of 0.70 lb/MMBtu and a NO_X emission limit of 0.40 lb/MMBtu for Corette at 40 CFR 52.1396(c). In the final FIP, we are establishing a SO_2 emission limit of 0.57 lb/MMBtu and a NO_X emission limit of 0.35 lb/MMBtu. We have made this change as a result of the comments we received. One commenter stated that EPA must increase the limits to no less than 0.81 lb/MMBtu for SO_2 and 0.46 lb/MMBtu for NO_X in order to account for compliance over a 30-day rolling average. By contrast, another commenter stated that our proposed emission limits were too high and would actually result in increased emissions.

Based on these comments, we have reassessed the SO_2 and NO_X emission limits for Corette. In order to establish appropriate emission limits, we conducted a statistical analysis of the monthly emissions data contained in the CAMD emissions system. For the period 2000–2010, the 99th percentile monthly SO_2 emission rate was 0.548 lb/MMbtu. Similarly, the 99th percentile monthly NO_X emission rate was 0.335 lb/MMBtu. In our final action, we are establishing emission limits slightly above these 99th percentile emission rates in order to allow a sufficient margin for compliance. This is because the emission limits must apply at all times, including during startup, shutdown, and malfunction. The revised emission rates are 0.57 lb/MMBtu for SO_2 and 0.35 lb/MMBtu for NO_X, both on a 30-day rolling average. We have revised the emission limits for Corette contained in section 52.1396(c)(1) accordingly.

B. Changes to 40 CFR 52.1396(c)(2)—Emission Limitations for Cement Kilns

In response to a comment from Holcim that EPA failed to consider the NO_X control technology already installed at the Trident cement plant, and that EPA failed to give proper weight to the excessively high average cost-effectiveness ($4,279/ton) and incremental cost-effectiveness ($8,029/ton) of a switch to indirect firing and a Low-NO_X Burner (LNB), we have removed switching to indirect firing and a LNB from consideration as an option for further reducing NO_X emissions and are treating any NO_X emission reduction that may have been achieved from installation of a new burner as part of the emissions baseline. We have recalculated the BART limit for NO_X to reflect a 50% reduction in NO_X emissions from that baseline by addition of SNCR alone, rather than the 58% reduction we previously used, which reflected a switch to indirect firing and LNB plus SNCR. The recalculated NO_X BART limit is 6.5 lb/ton clinker. We have replaced the NO_X emission limit of 5.5 lb/ton clinker from our proposal with 6.5 lb/ton clinker, on a 30-day rolling average.

Also, during our evaluation of comments on PM BART from Ash Grove, we found that the table of emission limits for cement kilns, at section 52.1396(c)(2) of our proposal, needed to clarify that the PM emission limit for Ash Grove is in lb/hr, not lb/ton clinker. Only the PM emission limit for Holcim is in lb/ton clinker. The column header for PM emission limits for both cement kilns erroneously said ''lb/ton clinker.'' We have corrected this error by changing the header from ''PM Emission Limit (lb/ton clinker)'' to ''PM Emission Limit.'' We did not change the text of the PM emission limit for Ash Grove, as it is already clear in that text that the limit is in lb/hr. However, at the bottom of the column, we have clarified the PM emission limit for Holcim to say ''0.77 lb/ton clinker'' rather than''0.77 lb/ton.''

C. Change to 40 CFR 52.1396(d)—Compliance Date

In response to a comment from Ash Grove which identified the failure of our regulatory text at 40 CFR 52.1396(d) to specify the SO_2 and PM compliance dates described in the preamble to our proposed rule, we have revised 40 CFR 52.1396(d) to read as follows:

> The owners and operators of the BART sources subject to this section shall comply with the emissions limitations and other requirements of this section as follows, unless otherwise indicated in specific paragraphs: Compliance with PM limits is required within 30 days of the effective date of this rule. Compliance with SO_2 and NO_X limits is required within 180 days of the effective date of this rule, unless installation of additional emission controls is necessary to comply with emission limitations under this rule, in which case compliance is required within five years of the effective date of this rule.

D. Change to 40 CFR 52.1396(e)(3)—CEMS for Cement Kilns

In response to a comment from Ash Grove Cement that this section should be revised to include an exception from CEMS data collection during CEMS breakdowns, repairs, calibration checks and zero and span adjustments, we have added the following language from 40 CFR part 60, subpart F, New Source Performance Standards for cement kilns, at 40 CFR 60.63(b):

> You must operate the monitoring system and collect data at all required intervals at all times the affected source is operating, except for periods of monitoring systems malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments).

Also, during our evaluation of comments from Ash Grove on CEMS requirements, we found that section 52.1396(e)(3) inadvertently failed to cross-reference the requirements for CEMS for cement kilns at 40 CFR 60.63(g). Section 52.1396(e)(3) only cross-referenced 60.63(f). There are important requirements for cement kiln CEMSs at 40 CFR 60.63(g), as well as important CEMS requirements at 60.63(h) which are cross-referenced only by 60.63(g) and not by 60.63(f). We have therefore added ''and (g),'' such that the first sentence of section 52.1396(e)(3) now reads as follows:

> At all times after the compliance date specified in paragraph (d) of this section, the owner/operator of each unit shall maintain,

calibrate, and operate a CEMS, in full compliance with the requirements found at 40 CFR 60.63(f) and (g), to accurately measure concentration by volume of SO_2 and NO_X emissions into the atmosphere from each unit.

E. Change to 40 CFR 52.1396(e)(4)(ii)—Compliance Determination Methods for SO_2 and NO_X at Cement Kilns

In response to a comment from Ash Grove that the formula at section 52.1396(e)(4)(ii) of our proposal incorrectly expresses the concentrations of SO_2 and NO_X in grains per dry standard cubic foot, rather than in parts per million, we have deleted the equation E = (CsQs)/(PK) from this section, as well as the definitions of terms in that equation, and replaced it with the following equation, which appears in the proposed amendments to 40 CFR part 60, subpart F, New Source Performance Standards for cement kilns, published in the **Federal Register** on July 18, 2012:

$$E_D = k \frac{1}{(n)} \sum_{i=1}^{n} C_i Q_i / P_i$$

Where:

E_D = 30 kiln operating day average emission rate of NO_X or SO_2, lb/ton of clinker;
C_i = Concentration of NO_X or SO_2 for hour i, ppm;
Q_i = volumetric flow rate of effluent gas for hour i, where
C_i and Q_i are on the same basis (either wet or dry), scf/hr;
P_i = total kiln clinker produced during production hour i, ton/hr;
k = conversion factor, 1.194×10^{-7} for NO_X and 1.660×10^{-7} for SO_2
n = number of kiln operating hours over 30 kiln operating days, n = 1 to 720.
For each kiln operating hour for which you do not have at least one valid 15-minute CEMS data value, use the average emissions rate (lb/hr) from the most recent previous hour for which valid data are available.

F. Change to 40 CFR 52.1396(f)(1) and (f)(2)—Compliance Determinations for PM BART Limits at EGUs and Cement Kilns

In response to a verbal comment from Holcim, in a meeting with EPA in June of 2012 on the proposed FIP, that BART sources should be allowed to retain the PM stack testing schedule already established under State permits, we have added the following sentence, after the sentence in sections 52.1396(f)(1) and (f)(2) that requires the first annual PM performance stack test for PM within 60 days after the PM compliance deadline:

The results from a stack test meeting the requirements of this paragraph that was completed within 12 months prior to the compliance deadline can be used in lieu of the first stack test required. If this option is chosen, then the next annual stack test shall be due no more than 12 months after the stack test that was used.

The meeting between Holcim and EPA is documented in the docket for this rulemaking.

G. Change to 40 CFR 52.1396(f)(2)—Compliance Determinations for Cement Kiln PM BART Limits

Consistent with our clarification of the table of PM emission limits for cement kilns at 40 CFR 52.1396(c)(2), we have clarified 40 CFR 52.1396(f)(2), to indicate that the emission rate of PM shall be reported in lb/hr for Ash Grove and in lb/ton clinker for Holcim. We have also clarified that the average of the results of three test runs for PM shall be used for demonstrating compliance. Specifically, we have added the following language after the third sentence of section 52.1396(f)(2):

The average of the results of three test runs shall be used for demonstrating compliance. For Ash Grove, the emission rate of particulate matter shall be computed for each run in pounds per hour (lb/hr). For Holcim, the emission rate (E) of particulate matter shall be computed for each run in lb/ton clinker, using the following equation: * * *

We have also revised section 52.1396(f)(2) in response to a comment from Ash Grove that the equation at 40 CFR 52.1396(e)(4)(ii), cross-referenced by this section 52.1396(f)(2), for calculating emissions in lb/ton clinker, is not valid for calculating SO_2 and NO_X emissions, but is only valid for calculating PM emissions. Therefore, we have moved this equation from section 52.1396(e)(4)(ii) to section 52.1396(f)(2). We have also changed the pollutant in the equation to PM. We have also clarified (as explained above) that the equation is to be used for calculating PM in lb/ton clinker only for Holcim, not for Ash Grove (which, as explained above, is subject to a PM emission limit in lb/hr, not in lb/ton clinker). Below is the equation we have now inserted into section 52.1396(f)(2), immediately after the revised text described above:

E = (CsQs)/(PK)

Where:

E = emission rate of PM, lb/ton of clinker produced
Cs = concentration of PM in grains per standard cubic foot (gr/scf)
Qs = volumetric flow rate of effluent gas, where Cs and Qs are on the same basis (either wet or dry), scf/hr
P = total kiln clinker production rate, tons/hr, and
K = conversion factor, 7000 gr/lb

We have also deleted the cross-reference to section 52.1396(e)(4)(ii) for this equation.

H. Change to 40 CFR 52.1396(h)(6)—Recordkeeping Requirements for Cement Kilns

In response to a comment from Ash Grove that the reference to ''40 CFR Part 75'' should be deleted because Part 75 applies only to electrical generating units, not to cement kilns, we have deleted that reference. We note that since the monitoring requirements for cement kilns in the FIP, at 40 CFR 52.1396(e)(3) and (4), and at 40 CFR 52.1396(f)(2), do not cross-reference Part 75, there are no applicable Part 75 recordkeeping requirements in the FIP. Section 52.1396(h)(6) now reads as follows:

Any other records required by 40 CFR part 60, subpart F, or 40 CFR part 60, Appendix F, Procedure 1.

I. Changes to 40 CFR 52.1396(i)—Reporting

In response to a comment from Ash Grove that the first sentence of this section mistakenly references 40 CFR 53.1395(n) and (o), rather than 52.1396(n) and (o), we have made the correction.

J. Change to 40 CFR 52.1396(i)(1) and (i)(2)—Reporting for CEMS for SO_2 and NO_X

In response to a comment from Ash Grove that the reporting frequency for CEMS excess emission reports and CEMS performance reports for cement kilns should be changed from quarterly to semiannual, because reporting requirements under other programs (Title V and NESHAP) only require semiannual reporting, we have changed the frequency to semiannual, but have kept the frequency at quarterly for EGUs.

We note that the general provisions of NSPS subpart A, at 40 CFR 60.7(c), which we used as a template for our FIP provisions for CEMS reporting, require semiannual excess emission reports and monitoring system performance reports, except when more frequent reporting is specifically required by an applicable subpart, or if the Administrator, on a case-by-case basis, determines that more frequent report is necessary to accurately assess the compliance status of the source. NSPS subpart F for cement kilns does not specify more frequent reporting.

Therefore, we have deleted ''quarterly'' from the first sentence of section 52.1396(i)(1) and from the first sentence of section 52.1396(i)(2). After the first sentence in each of those sections, we have inserted the following sentence: ''Reports shall be submitted quarterly for EGUs and semiannually for cement kilns.''

K. Changes to 40 CFR 52.1396 for Devon Energy, Blaine County #1 Compressor Station

In the final FIP, we are clarifying testing requirements, monitoring, recordkeeping and reporting requirements, and emission limitations for Devon Energy, Blaine County #1 Compressor Station. We made these changes in response to a comment stating that the requirements for this source were not practically enforceable.

We have changed the text at 40 CFR 52.1396(c)(3) to read, ''The owners/operators of LP, Blaine County #1 Compressor Station shall not emit or cause to be emitted from each 5,500 horsepower Ingersoll Rand 616 natural gas-fired compressor engine installed at the facility, total NO_X in excess of 21.8 lbs/hr (average of three stack test runs).'' We have made this change to clarify that the emission limit of 21.8 lbs/hr applies to each of the 5,500 horsepower Ingersoll Rand 616 natural gas-fired compressor engines installed at the facility and that the emission rate will be determined by averaging the results of three stack test runs.

We have changed the text at 40 CFR 52.1396(e)(5) to read, ''The owner/operator of Blaine County #1 Compressor Station shall install a temperature-sensing device (i.e. thermocouple or resistance temperature detectors) before the catalyst in order to monitor the inlet temperatures of the catalyst for each engine. The owner/operator shall maintain the exhaust temperature at the inlet to the catalyst for each engine at a minimum of least 750 °F and no more than 1250 °F in accordance with the catalyst manufacturer's specifications. Also, the owner/operator shall install gauges before and after the catalyst for each engine in order to monitor pressure drop across the catalyst, and that the owner/operator maintain the pressure drop within ± 2'' water at 100% load plus or minus 10% from the pressure drop across the catalyst measured during the initial performance test. The owner/operator shall follow the manufacturer's recommended maintenance schedule and procedures for each engine and its respective catalyst. The owner/operator shall only fire each engine with natural gas that is of pipeline-quality in all respects except that the CO_2 concentration in the gas shall not be required to be within pipeline-quality.'' We have made this change to clarify that it is the exhaust temperature that must be maintained at a minimum of at least 750 °F and no more than 1250 °F in accordance with the catalyst manufacturer's specifications, and not the engine temperature that must be kept within this temperature range. We are also making this change to clarify that the temperature range must be kept in accordance with the catalyst manufacturer's specifications and not the engine manufacturer's specifications.

We have added a new section, 40 CFR 52.1396(j) which includes testing requirements for Blaine County #1 Compressor Station. This section was inadvertently omitted from the proposed FIP, but is necessary to ensure adequate testing is performed to ensure compliance with the NO_X emission limit for Blaine County #1 Compressor Station.

We have changed 40 CFR 52.1396(k)(1) to read: ''The owner/operator shall measure NO_X emissions from each engine at least semi-annually or once every six-month period to demonstrate compliance with the emission limits. To meet this requirement, the owner/operator shall measure NO_X emissions from each engine using a portable analyzer and a monitoring protocol approved by EPA.'' We have changed the first sentence from referring to engines to refer to each engine to clarify that NO_X emissions must be measured from each engine.

We have added a new paragraph at 40 CFR 52.1396(k)(9) to read, ''The owner/operator shall keep records of all deviations from the emission limit or operating requirements (e.g., catalyst inlet temperature, pressure drop across the catalyst) for each engine. The records shall include: The date and time of the deviation, the name and title of the observing employee and a brief description of the deviation and the measures taken to address the deviation and prevent future occurrences.'' We have made this change to ensure that adequate records are kept by the owner or operator of Blaine County #1 Compressor Station to demonstrate compliance with the required emission limit and appropriate operation of the NSCR system.

We have changed the text of 40 CFR 52.1396(k)(10) to correct a typographical error and to add to the requirements that the owner/operator of Blaine County #1 Compressor Station must maintain records of deviations from operating requirements for a period of at least five years and that these records must be made available upon request by EPA.

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review 13563

This action will finalize a SIP approval for a revision to Montana's Smoke Management plan and a source-specific Regional Haze FIP for imposing federal controls to meet BART requirements for PM, NO_X and SO_2 emissions on five specific units at four sources in Montana (Ash Grove, Holcim, Colstrip Units 1 and 2, and Corette) and imposing controls to meet RP requirements for NO_X emissions at one additional source (Devon) in Montana. The net result of the FIP action is that EPA is proposing direct emission controls on selected units at five sources. The sources in question are two large electric generating plants (one plant includes two units), two cement plants, and one gas compressor station. This action also imposes notification requirements on CFAC and M2Green Redevelopment LLC. This type of action is exempt from review under Executive Orders 12866 (58 FR 51735, October 4, 1993) and 13563 (76 FR 3821, January 21, 2011).

B. Paperwork Reduction Act

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

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

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

C. Regulatory Flexibility Act

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

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

After considering the economic impacts of this action on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. The Regional Haze FIP that EPA is finalizing consists of imposing federal controls to meet BART and RP requirements for PM, NO_X and SO_2 emissions on specific sources as described above in section A. None of these sources are owned by small entities, and therefore are not small entities.

D. Unfunded Mandates Reform Act (UMRA)

This rule does not contain a Federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any one year. Table 1 notes that the cumulative total annual costs for this action are $13.7 million. Thus, this rule is not subject to the requirements of sections 202 or 205 of UMRA.

This rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132, because it merely addresses the State of Montana not meeting its obligation to adopt a SIP that meets the regional haze requirements under the CAA. Thus, Executive Order 13132 does not apply to this action. In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and state and local governments, EPA specifically solicited comment on this rule from state and local officials. A summary of each comment and EPA's response to those comments is provided in section IV of this preamble.

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

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). This action applies to only seven sources in Montana. Thus, Executive Order 13175 does not apply to this rule. Although Executive Order 13175 does not apply to this action, EPA did send letters, dated October 7, 2011, to each of the Montana tribes explaining our regional haze FIP action and offering consultation. We did not receive any written or verbal requests from the Montana tribes for more information or for consultation. As a follow-up to our letter, we invited all of the tribes to a January 5, 2012 conference call. The call was attended by tribal Air Program Managers and one Environmental Director from tribes from four reservations. We also met with the Montana tribes prior to the start of the public hearings held in Helena and Billings, Montana. EPA specifically solicited additional comment on this rule from tribal officials and we received comments and responded to them in section IV of this preamble.

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

Executive Order 13045: *Protection of Children from Environmental Health Risks and Safety Risks* (62 FR 19885, April 23, 1997), applies to any rule that: (1) Is determined to be economically significant as defined under Executive Order 12866; and (2) concerns an environmental health or safety risk that we have reason to believe may have a disproportionate effect on children. EPA interprets EO 13045 as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the EO has the potential to influence the regulation. This action is not subject to EO 13045 because it implements specific standards established by Congress in statutes. However, to the extent this rule limits emissions of NO_X, SO_2, and PM, the rule will have a beneficial effect on children's health by reducing air pollution.

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

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

I. National Technology Transfer and Advancement Act

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

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

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

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

We have determined that this rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. This rule limits emissions of NO_X, SO_2, and PM from five sources in Montana.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. Section 804 exempts from section 801 the following types of rules (1) rules of particular applicability; (2) rules relating to agency management or personnel; and (3) rules of agency organization, procedure, or practice that do not substantially affect the rights or obligations of non-agency parties. 5 U.S.C 804(3). EPA is not required to submit a rule report regarding today's action under section 801 because this action is a rule of particular applicability. This rule finalizes a FIP for seven sources.

L. Judicial Review

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by November 19, 2012. Pursuant to CAA section 307(d)(1)(B), this action is subject to the requirements of CAA section 307(d) as it promulgates a FIP under CAA section 110(c). Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements. See CAA section 307(b)(2).

List of Subjects in 40 CFR Part 52

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

Dated: August 15, 2012.

Lisa P. Jackson,

Administrator.

40 CFR part 52 is amended as follows:

PART 52—[AMENDED]

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

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

Subpart BB—Montana

■ 2. Section 52.1370 is amended by revising paragraph (c)(27)(i)(H) to read as follows:

§ 52.1370 Identification of plan.

* * * * *

(c) * * *

(27) * * *

(i) * * *

(H) Appendix G–2, Montana Smoke Management Plan, effective April 15, 1988, is removed and replaced by § 52.1395.

* * * * *

■ 3. Add section 52.1395 to read as follows:

§ 52.1395 Smoke management plan.

The Department considers smoke management techniques for agriculture and forestry management burning purposes as set forth in 40 CFR 51.308(d)(3)(v)(E). The Department considers the visibility impact of smoke when developing, issuing, or conditioning permits and when making dispersion forecast recommendations through the implementation of Title 17, Chapter 8, subchapter 6, ARM, Open Burning.

■ 4. Add section 52.1396 to read as follows:

§ 52.1396 Federal implementation plan for regional haze.

(a) *Applicability.* This section applies to each owner and operator of the following coal fired electric generating units (EGUs) in the State of Montana: PPL Montana, LLC, Colstrip Power Plant, Units 1, 2; and PPL Montana, LLC, JE Corette Steam Electric Station. This section also applies to each owner and operator of cement kilns at the following cement production plants: Ash Grove Cement, Montana City Plant; and Holcim (US) Inc. Cement, Trident Plant. This section also applies to each owner or operator of Blaine County #1 Compressor Station. This section also applies to each owner and operator of CFAC and M2 Green Redevelopment LLC, Missoula site.

(b) *Definitions.* Terms not defined below shall have the meaning given them in the Clean Air Act or EPA's regulations implementing the Clean Air Act. For purposes of this section:

Boiler operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the EGU. It is not necessary for fuel to be combusted for the entire 24-hour period.

Continuous emission monitoring system or CEMS means the equipment required by this section to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of SO_2 or NO_X emissions, other pollutant emissions, diluent, or stack gas volumetric flow rate.

Kiln operating day means a 24-hour period between 12 midnight and the following midnight during which the kiln operates.

NO_X means nitrogen oxides.

Owner/operator means any person who owns or who operates, controls, or supervises an EGU identified in paragraph (a) of this section.

PM means filterable total particulate matter.

SO_2 means sulfur dioxide.

Unit means any of the EGUs or cement kilns identified in paragraph (a) of this section.

(c) *Emissions limitations.* (1) The owners/operators of EGUs subject to this section shall not emit or cause to be emitted PM, SO_2 or NO_X in excess of the following limitations, in pounds per million British thermal units (lb/MMBtu), averaged over a rolling 30-day period for SO_2 and NO_X:

Source name	PM emission limit (lb/MMBtu)	SO_2 emission limit (lb/MMBtu)	NO_X emission limit (lb/MMBtu)
Colstrip Unit 1	0.10	0.08	0.15
Colstrip Unit 2	0.10	0.08	0.15
JE Corette Unit 1	0.26	0.57	0.35

(2) The owners/operators of cement kilns subject to this section shall not emit or cause to be emitted PM, SO_2 or NO_X in excess of the following limitations, in pounds per ton of clinker produced, averaged over a rolling 30-day period for SO_2 and NO_X:

Source name	PM emission limit	SO_2 emission limit (lb/ton clinker)	NO_X emission limit (lb/ton clinker)
Ash Grove Cement	If the process weight rate of the kiln is less than or equal to 30 tons per hour, then the emission limit shall be calculated using $E = 4.10p^{0.67}$ where E = rate of emission in pounds per hour and p = process weight rate in tons per hour; however, if the process weight rate of the kiln is greater than 30 tons per hour, then the emission limit shall be calculated using $E = 55.0p^{0.11} - 40$, where E = rate of emission in pounds per hour and P = process weight rate in tons per hour.	11.5	8.0
Holcim (US) Inc	0.77 lb/ton clinker	1.3	6.5

(3) The owners/operators of LP, Blaine County #1 Compressor Station shall not emit or cause to be emitted from each 5,500 horsepower Ingersoll Rand 616 natural gas-fired compressor engine installed at the facility total NO_X in excess of 21.8 lbs/hr (average of three stack test runs).

(4) These emission limitations shall apply at all times, including startups, shutdowns, emergencies, and malfunctions.

(d) *Compliance date.* The owners and operators of Blaine County #1 Compressor Station shall comply with the emissions limitation and other requirements of this section as expeditiously as practicable, but no later than July 31, 2018. The owners and operators of the BART sources subject to this section shall comply with the emissions limitations and other requirements of this section as follows, unless otherwise indicated in specific paragraphs: Compliance with PM limits is required within 30 days of the effective date of this rule. Compliance with SO_2 and NO_X limits is required within 180 days of the effective date of this rule, unless installation of additional emission controls is necessary to comply with emission limitations under this rule, in which case compliance is required within five years of the effective date of this rule.

(e) *Compliance determinations for SO_2 and NO_X.* (1) *CEMS for EGUs.* At all times after the compliance date specified in paragraph (d) of this section, the owner/operator of each unit shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found at 40 CFR part 75, to accurately measure SO_2, NO_X, diluent, and stack gas volumetric flow rate from each unit. The CEMS shall be used by the owner/operator to determine compliance with the emission limitations in paragraph (c) of this section for each unit.

(2) *Method for EGUs.* (i) For any hour in which fuel is combusted in a unit, the owner/operator of each unit shall calculate the hourly average SO_2 and NO_X concentration in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR part 75. At the end of each boiler operating day, the owner/operator shall calculate and record a new 30-day rolling average emission rate in lb/MMBtu from the arithmetic average of all valid hourly emission rates from the CEMS for the current boiler operating day and the previous 29 successive boiler operating days.

(ii) An hourly average SO_2 or NO_X emission rate in lb/MMBtu is valid only if the minimum number of data points, as specified in 40 CFR part 75, is acquired by the owner/operator for both the pollutant concentration monitor (SO_2 or NO_X) and the diluent monitor (O_2 or CO_2).

(iii) Data reported by the owner/operator to meet the requirements of this section shall not include data substituted using the missing data substitution procedures of subpart D of 40 CFR part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR part 75.

(3) *CEMS for cement kilns.* At all times after the compliance date specified in paragraph (d) of this section, the owner/operator of each unit shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found at 40 CFR 60.63(f) and (g), to accurately measure concentration by volume of SO_2 and NO_X emissions into the atmosphere from each unit. The CEMS shall be used by the owner/operator to determine compliance with the emission limitations in paragraph (c) of this section for each unit, in combination with data on actual clinker production. The owner/operator must operate the monitoring system and collect data at all required intervals at all times the affected unit is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments).

(4) *Method for cement kilns.* (i) The owner/operator of each unit shall record the daily clinker production rates.

(ii) The owner/operator of each unit shall calculate and record the 30-operating day rolling emission rates of SO_2 and NO_X, in lb/ton of clinker produced, as the total of all hourly emissions data for the cement kiln in the preceding 30 days, divided by the total tons of clinker produced in that kiln during the same 30-day operating period, using the following equation:

$$E_D = k \frac{1}{(n)} \sum_{i=1}^{n} C_i Q_i / P_i$$

Where:

E_D = 30 kiln operating day average emission rate of NO_X or SO_2, lb/ton of clinker;
C_i = Concentration of NO_X or SO_2 for hour i, ppm;
Q_i = volumetric flow rate of effluent gas for hour i, where
C_i and Q_i are on the same basis (either wet or dry), scf/hr;
P_i = total kiln clinker produced during production hour i, ton/hr;
k = conversion factor, 1.194×10^{-7} for NO_X and 1.660×10^{-7} for SO_2; and.
n = number of kiln operating hours over 30 kiln operating days, n = 1 to 720.

For each kiln operating hour for which the owner/operator does not have at least one valid 15-minute CEMS data value, the owner/operator must use the average emissions rate (lb/hr) from the most recent previous hour for which valid data are available. Hourly clinker production shall be determined by the owner/operator in accordance with the requirements found at 40 CFR 60.63(b).

(iii) At the end of each kiln operating day, the owner/operator of each unit shall calculate and record a new 30-day rolling average emission rate in lb/ton clinker from the arithmetic average of all valid hourly emission rates for the current kiln operating day and the previous 29 successive kiln operating days.

(5) *Method for compressor station.* The owner/operator of Blaine County #1 Compressor Station shall install a temperature-sensing device (i.e. thermocouple or resistance temperature detectors) before the catalyst in order to monitor the inlet temperatures of the catalyst for each engine. The owner/operator shall maintain the exhaust temperature at the inlet to the catalyst for each engine at a minimum of least 750 °F and no more than 1250 °F in accordance with the catalyst manufacturer's specifications. Also, the owner/operator shall install gauges before and after the catalyst for each engine in order to monitor pressure drop across the catalyst. During the initial performance test the owner/operator maintain the pressure drop within ± 2″ water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured. The owner/operator shall follow the manufacturer's recommended maintenance schedule and procedures for each engine and its respective catalyst. The owner/operator shall only fire each engine with natural gas that is of pipeline-quality in all respects except that the CO_2 concentration in the gas shall not be required to be within pipeline-quality.

(f) *Compliance determinations for particulate matter.*

(1) *EGU particulate matter BART limits.* Compliance with the particulate matter BART emission limits for each EGU BART unit shall be determined by the owner/operator from annual performance stack tests. Within 60 days of the compliance deadline specified in paragraph (d) of this section, and on at least an annual basis thereafter, the owner/operator of each unit shall conduct a stack test on each unit to measure particulate emissions using EPA Method 5, 5B, 5D, or 17, as appropriate, in 40 CFR part 60, Appendix A. A test shall consist of three runs, with each run at least 120 minutes in duration and each run collecting a minimum sample of 60 dry standard cubic feet. Results shall be reported by the owner/operator in lb/MMBtu. The results from a stack test meeting the requirements of this paragraph that were completed within 120 days prior to the compliance date can be used by the owner/operator in lieu of the first stack test required. In addition to annual stack tests, owner/operator shall monitor particulate emissions for compliance with the BART emission limits in accordance with the applicable Compliance Assurance Monitoring (CAM) plan developed and approved in accordance with 40 CFR part 64.

(2) *Cement kiln particulate matter BART limits.* Compliance with the particulate matter BART emission limits for each cement kiln shall be determined by the owner/operator from annual performance stack tests. Within 60 days of the compliance deadline specified in paragraph (d) of this section, and on at least an annual basis thereafter, the owner/operator of each unit shall conduct a stack test on each unit to measure particulate matter emissions using EPA Method 5, 5B, 5D, or 17, as appropriate, in 40 CFR part 60, Appendix A. A test shall consist of three runs, with each run at least 120 minutes in duration and each run collecting a minimum sample of 60 dry standard cubic feet. The average of the results of three test runs shall be used by the owner/operator for demonstrating compliance.

Clinker production shall be determined in accordance with the requirements found at 40 CFR 60.63(b). Results of each test shall be reported by the owner/operator as the average of three valid test runs. In addition to annual stack tests, owner/operator shall monitor particulate emissions for compliance with the BART emission limits in accordance with the applicable Compliance Assurance Monitoring (CAM) plan developed and approved in accordance with 40 CFR part 64.

(i) For Ash Grove Cement, the emission rate of particulate matter shall be computed by the owner/operator for each run in pounds per hour (lb/hr).

(ii) For Holcim, the emission rate (E) of particulate matter shall be computed by the owner/operator for each run in lb/ton clinker, using the following equation:

$$E = (C_s Q_s)/PK$$

Where:

E = emission rate of PM, lb/ton of clinker produced;
C_s = concentration of PM in grains per standard cubic foot (gr/scf);
Q_s = volumetric flow rate of effluent gas, where C_s and Q_s are on the same basis (either wet or dry), scf/hr;
P = total kiln clinker production, tons/hr; and
K = conversion factor, 7000 gr/lb,

(g) *Recordkeeping for EGUs.* The owner/operator shall maintain the following records for at least five years:

(1) All CEMS data, including the date, place, and time of sampling or measurement; parameters sampled or measured; and results.

(2) Records of quality assurance and quality control activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Part 75.

(3) Records of all major maintenance activities conducted on emission units, air pollution control equipment, and CEMS.

(4) Any other records required by 40 CFR part 75.

(5) All particulate matter stack test results.

(h) *Recordkeeping for cement kilns.* The owner/operator shall maintain the following records for at least five years:

(1) All CEMS data, including the date, place, and time of sampling or measurement; parameters sampled or measured; and results.

(2) All particulate matter stack test results.

(3) All records of clinker production.

(4) Records of quality assurance and quality control activities for emissions measuring systems including, but not limited to, any records required by 40 CFR part 60, appendix F, Procedure 1.

(5) Records of all major maintenance activities conducted on emission units, air pollution control equipment, CEMS and clinker production measurement devices.

(6) Any other records required by 40 CFR part 60, Subpart F, or 40 CFR part 60, Appendix F, Procedure 1.

(i) *Reporting.* All reports under this section, with the exception of 40 CFR 52.1396(n) and (o), shall be submitted by the owner/operator to the Director, Office of Enforcement, Compliance and Environmental Justice, U.S. Environmental Protection Agency, Region 8, Mail Code 8ENF–AT, 1595 Wynkoop Street, Denver, Colorado 80202–1129.

(1) The owner/operator of each unit shall submit excess emissions reports for SO_2 and NO_X BART limits. Reports shall be submitted quarterly by the owner/operator for EGUs and semiannually for cement kilns, no later than the 30th day following the end of each calendar quarter or semiannual period, respectively. Excess emissions means emissions that exceed the emissions limits specified in paragraph (c) of this section. The reports shall include the magnitude, date(s), and duration of each period of excess emissions, specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the unit, the nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted.

(2) The owner/operator of each unit shall submit CEMS performance reports, to include dates and duration of each period during which the CEMS was inoperative (except for zero and span adjustments and calibration checks), reason(s) why the CEMS was inoperative and steps taken to prevent recurrence, and any CEMS repairs or adjustments. The owner/operator shall submit reports quarterly for EGUs and semiannually for cement kilns.

(i) *For EGUs:* The owner/operator of each unit shall also submit results of any CEMS performance tests required by 40 CFR part 75 (Relative Accuracy Test Audits, Relative Accuracy Audits, and Cylinder Gas Audits).

(ii) *For cement kilns:* Owner/operator of each unit shall also submit results of any CEMS performance tests required by 40 CFR part 60, appendix F, Procedure 1 (Relative Accuracy Test Audits, Relative Accuracy Audits, and Cylinder Gas Audits).

(3) When no excess emissions have occurred or the CEMS has not been inoperative, repaired, or adjusted during the reporting period, the owner/operator shall state such information in the quarterly reports required by sections (h)(1) and (2) of this section.

(4) The owner/operator of each unit shall submit results of any particulate matter stack tests conducted for demonstrating compliance with the particulate matter BART limits in paragraph (c) of this section within 60 days after the completion of the test.

(5) The owner/operator of each unit shall submit semi-annual reports of any excursions under the approved CAM plan in accordance with the schedule specified in the source's title V permit.

(j) Testing requirements for Blaine County #1 Compressor Station:

(1) An initial performance test shall be conducted by the owner/operator for each engine for measuring NO_X emissions from the engines to demonstrate initial compliance with the emission limits. The initial performance test shall be conducted by the owner/operator as expeditiously as practicable, but no later than October July 31, 2018.

(2) Upon change out of the catalyst for each engine a performance test shall be conducted by the owner/operator for measuring NO_X from the engines to demonstrate compliance with the emission limits and re-establish temperature and pressure correlations. The performance test shall be conducted by the owner/operator within 90 calendar days of the date of the catalyst change out.

(3) The performance tests for NO_X shall be conducted by the owner/operator in accordance with the test methods specified in 40 CFR Part 60, Appendix A. EPA Reference Method 7E shall be used to measure NO_X emissions.

(4) All tests conducted by the owner/operator for NO_X emissions must meet the following requirements:

(i) All tests shall be performed at a maximum operating rate (90 to 110 percent of engine capacity at site elevation).

(ii) During each test run, data shall be collected on all parameters necessary to document how NO_X emissions in pounds per hour were measured or calculated (such as test run length, minimum sample volume, volumetric flow rate, moisture and oxygen corrections, etc.). The temperature at the inlet to the catalyst and the pressure drop across the catalyst shall also be measured and recorded during each test run for each engine.

(iii) Each source test shall consist of at least three 1-hour or longer valid test runs. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of the emission limits (pounds per hour).

(iv) A source test plan for NO_X emissions shall be submitted to EPA at least 45 calendar days prior to the scheduled performance test.

(v) The source test plan shall include and address the following elements:

(A) Purpose of the test;

(B) Engines and catalysts to be tested;

(C) Expected engine operating rate(s) during test;

(D) Schedule/date(s) for test;

(E) Sampling and analysis procedures (sampling locations, test methods, laboratory identification);

(F) Quality assurance plan (calibration procedures and frequency, sample recovery and field documentation, chain of custody procedures); and

(G) Data processing and reporting (description of data handling and quality control procedures).

(k) Monitoring, recordkeeping, and reporting requirements for Blaine County #1 Compressor Station:

(1) The owner/operator shall measure NO_X emissions from each engine at least semi-annually or once every six month period to demonstrate compliance with the emission limits. To meet this requirement, the owner/operator shall measure NO_X emissions from each engine using a portable analyzer and a monitoring protocol approved by EPA.

(2) The owner/operator shall submit the analyzer specifications and monitoring protocol to EPA for approval within 45 calendar days prior to installation of the NSCR unit.

(3) Monitoring for NO_X emissions shall commence during the first complete calendar quarter following the owner/operator's submittal of the initial performance test results for NO_X to EPA.

(4) The owner/operator shall measure the engine exhaust temperature at the inlet to the oxidation catalyst at least once per week and shall measure the pressure drop across the oxidation catalyst monthly.

(5) The owner/operator shall ensure that each temperature-sensing device is accurate to within plus or minus 0.75% of span and that the pressure sensing devices be accurate to within plus or minus 0.1 inches of water.

(6) The owner/operator shall keep records of all temperature and pressure measurements; vendor specifications for the thermocouples and pressure gauges; vendor specifications for the NSCR catalyst and the air-to-fuel ratio controller on each engine.

(7) The owner/operator shall keep records sufficient to demonstrate that the fuel for the engines is pipeline-quality natural gas in all respects, with the exception of the CO_2 concentration in the natural gas.

(8) The owner/operator shall keep records of all required testing and monitoring that include: The date, place, and time of sampling or measurements; the date(s) analyses were performed; the company or entity that performed the analyses; the analytical techniques or methods used; the results of such analyses or measurements; and the operating conditions as existing at the time of sampling or measurement.

(9) The owner/operator shall keep records of all deviations from the emission limit or operating requirements (e.g., catalyst inlet temperature, pressure drop across the catalyst) for each engine. The records shall include: The date and time of the deviation, the name and title of the observing employee and a brief description of the deviation and the measures taken to address the deviation and prevent future occurrences.

(10) The owner/operator shall maintain records of all required monitoring data, support information (e.g., all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required) and deviations from operating requirements for a period of at least five years from the date of the monitoring sample, measurement, or report and that these records be made available upon request by EPA.

(11) The owner/operator shall submit a written report of the results of the required performance tests to EPA within 90 calendar days of the date of testing completion.

(l) *Notifications.* (1) The owner/operator shall submit notification of commencement of construction of any equipment which is being constructed to comply with the SO_2 or NO_X emission limits in paragraph (c) of this section.

(2) The owner/operator shall submit semi-annual progress reports on construction of any such equipment.

(3) The owner/operator shall submit notification of initial startup of any such equipment.

(m) *Equipment operation.* At all times, the owner/operator shall maintain each unit, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

(n) *Credible evidence.* Nothing in this section shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with requirements of this section if the appropriate performance or compliance test procedures or method had been performed.

(o) *CFAC notification.* CFAC shall notify EPA 60 days in advance of resuming operation. CFAC shall submit such notice to the Director, Air Program, U.S. Environmental Protection Agency, Region 8, Mail Code 8P–AR, 1595 Wynkoop Street, Denver, Colorado 80202–1129. Once CFAC notifies EPA that it intends to resume operation, EPA will initiate and complete a BART determination after notification and revise the FIP as necessary in accordance with regional haze requirements, including the BART provisions in 40 CFR 51.308(e). CFAC will be required to install any controls that are required as soon as practicable, but in no case later than five years following the effective date of this rule.

(p) *M2Green Redevelopment LLC notification.* M2Green Redevelopment LLC shall notify EPA 60 days in advance of resuming operation. M2Green Redevelopment LLC shall submit such notice to the Director, Air Program, U.S. Environmental Protection Agency, Region 8, Mail Code 8P–AR, 1595 Wynkoop Street, Denver, Colorado 80202–1129. Once M2 Green Redevelopment LLC notifies EPA that it intends to resume operation, EPA will initiate and complete a four factor analysis after notification and revise the FIP as necessary in accordance with regional haze requirements including the ''reasonable progress'' provisions in 40 CFR 51.308(d)(1). M2 Green Redevelopment LLC will be required to install any controls that are required as soon as practicable, but in no case later than July 31, 2018.

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