Potential Impacts of the Federal Regional Haze and Best Available Retrofit Technology Rules on the Taconite Industry in Minnesota

Final Report for the
Minnesota Pollution Control Agency

September 30, 2003

Barr Engineering Company
Project No. 23/62-833
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Table of Contents

List of Tables

List of Figures

List of Attachments

1 Project Introduction and Background

1.1 *Minnesota Pollution Control Agency Request for Proposal*

On December 9, 2002, the Minnesota Pollution Control Agency (MPCA) published in the State Register the availability of a request for proposal to survey and report on the potential impacts of the federal Regional Haze rule on the taconite industry in Minnesota. See Attachment A for a copy of the State Register notice and the request for proposal. This rule requires certain sources to conduct an initial analysis that may lead to a more detailed assessment and installation of emissions controls that conform to Best Available Retrofit Technology (BART) requirements in 40 CFR 51.308(e). The taconite industry has been identified by the MPCA as one of the industries for which a BART analysis is required. The MPCA requested that this project provide a general analysis for the industry as a whole that can be used by both the MPCA and the taconite industry as a basis for planning purposes and for any facility-specific detailed assessments that will follow. The analysis should be structured to help ensure that each facility conducts its engineering assessments the same way, the consistency of which will assist the MPCA in reviewing the assessments. The MPCA also requested that the project provide enough baseline information to initiate its own preliminary assessments, which are likely to be necessary to develop state implementation plan (SIP) submittals. The MPCA chose Barr Engineering Company (Barr) on January 27, 2003[1] to complete the project.

Barr Engineering Company's (Barr's) work plan to address MPCA's request includes the following tasks:

- Task 1: Hold working group coordination meeting.
- Task 2: Conduct taconite industry regional haze regulatory study.
- Task 3: Conduct general taconite industry BART screening analysis.
- Task 4: Evaluate BART affordability issues.
- Optional Task 2: Perform CALPUFF visibility impacts screening analysis.

Attachment C of this report contains Barr's work plan, located after the working group meeting minutes in the attachment.

1.2 *Working Group Coordination Meeting*

A necessary first step for this project is a coordination meeting with members of the working group. The working group includes MPCA and Barr personnel, representatives of the Minnesota taconite plants, representatives of Indian tribes, and other stakeholders. Task 1, a project kick-off meeting for the working group, was held at Barr's Minneapolis office on March 18, 2003. The

[1] January 27, 2003 phone conversation between Mr. Stuart Arkley of MPCA and Mr. George Pruchnofski of Barr.

purpose of the meeting was to (1) provide contact information, (2) establish lines of communication, and (3) review the project work plan.

Attachment C contains a copy of the meeting minutes in outline format and the meeting handouts that were sent via e-mail to the working group by Mr. Stuart Arkley on April 2, 2003. Included in this attachment is Barr's project work plan.

1.3 *Project Tasks and Draft Reports*

Task 2 of the project is to complete a regulatory study report that summarizes the Regional Haze and BART regulations as they may apply to the taconite industry in Minnesota. Barr submitted the draft regulatory study report for review by the working group on April 18, 2003. Revisions to the report were completed on May 12, 2003, pursuant to comments from the working group. This report incorporates and supersedes the May 12, 2003 draft report.

Task 3 of the project is to complete a BART screening evaluation of the taconite industry in order to provide information that will assist MPCA in developing baseline conditions for future BART evaluations. Barr submitted a draft report on July 11, 2003. Several comments were received on the draft report. Barr staff worked with each commenter to address concerns and has subsequently revised the draft report, as appropriate. This report incorporates and supersedes the July 11, 2003 draft report.

Task 4 of the project is to address the aspect of affordability in a BART evaluation. This task was completed on September 23, 2003; the results are included in this report.

Finally, Optional Task 2 of the project is to perform a dispersion modeling screening analysis of visibility impacts for the taconite industry before and after application of BART. This task was completed on September 23, 2003; the modeling protocol and results are included in this report.

2 Purpose and Format of Report

The objectives of this report are to:

1) Detail the potential regulatory applicability of Federal Regional Haze and BART rules to the taconite industry (Sections 3 and 4),
2) Describe the BART screening evaluation performed for the taconite industry (Sections 5 through 8),
3) Provide information to assist the MPCA in developing baseline conditions for future BART evaluations (Section 9), and
4) Summarize the visibility impacts screening analysis (Section 10).

Section 3 of this report provides a summary of the Regional Haze final rule as it applies to the taconite industry. This section serves to inform stakeholders of upcoming regulatory requirements under the Federal rule. As applicable, each provision of the rule is summarized, followed by a section discussing its relationship to the taconite industry.

Section 4 summarizes the BART Guidelines proposed rule as it applies to the taconite industry and recent court opinions concerning the legality of certain BART provisions and timing for promulgation of a final rule. As with Section 3 for the Regional Haze rule, Section 4 serves to inform stakeholders of upcoming regulatory requirements under the proposed BART rule.

Section 5 includes a summary description of the United States taconite iron ore industry, followed by a discussion of BART-eligible sources at Minnesota taconite facilities.

Section 6 identifies available control technologies for the taconite industry and screens out those technologies that are technically infeasible for a new or existing unit.

Section 7 steps through the BART screening evaluation for hypothetical model taconite sources.

Section 8 of this report provides information to assist the MPCA in further developing baseline conditions for BART based on existing regulatory programs. It includes a summary of air pollution regulatory requirements that apply to the taconite industry and a summary of taconite emissions source types and control types used to meet the regulatory requirements. This section also provides a review summary of the MPCA's existing emissions inventory of haze-generating pollutants for the taconite industry and BART-eligible sources. This section will help the MPCA to assess the effects of these programs in establishing BART for the industry and setting reasonable progress goals in developing the SIP. Also contained in this section is a summary of Michigan and Canadian air emissions control programs applicable to the taconite plants in these areas, as well as a summary of past best available control technology (BACT) determinations at taconite facilities.

Section 9 provides the results of attempts to assess the affordability of a BART evaluation for the taconite industry.

Section 10 summarizes the visibility impacts screening analysis performed using taconite industry pre-BART and hypothetical post-BART emissions. Although application of these modeling results is very limited, this analysis serves to provide generalized outcomes of visibility impacts at Boundary Waters Canoe Area Wilderness and Voyageurs National Park in Minnesota from the taconite industry.

Section 11 sets forth conclusions that can be drawn from the report.

3 Summary of Regional Haze Final Rule

The information provided in this section is based on EPA's July 1, 1999 "Regional Haze Regulations; Final Rule."[2] A copy of the Federal Register notice is contained in Attachment D. Section 3.1 provides historical background on the development of this rule. Section 3.2 is a summary of the Regional Haze program requirements with a discussion of how each provision relates to BART at the taconite facilities. Section 3.3 summarizes the current status of the Minnesota implementation plan for visibility protection. Section 3.4 describes how the requirements of the Regional Haze rule relate to emissions released from Indian Country.

3.1 *Background*

Section 169a of the Clean Air Act (CAA) sets forth a national goal for visibility which is the "prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas (Class I areas) which impairment results from manmade air pollution." All mandatory Class I Federal areas where visibility is an important value are listed in 40 CFR 81, subpart D. Of the 156 Class I areas in the United States where visibility is an important value[3] (see Figure 3-1), two are in Minnesota: the Boundary Waters Canoe Area Wilderness (BWCAW) and Voyageurs National Park.

Regional Haze is defined in 40 CFR Subpart P – Protection of Visibility, as:

> "…visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources."

The EPA promulgated regulations in 1980[4] to address visibility impairment that is "reasonably attributable" to one or a small group of sources, but EPA deferred action on Regional Haze regulations until monitoring, modeling, and scientific knowledge about the relationship between pollutants and the visibility effects improved. In 1993, the National Academy of Sciences (NAS) concluded that "current scientific knowledge is adequate and control technologies are available for taking regulatory action to improve and protect visibility." On July 31, 1997, EPA published proposed amendments to the 1980 regulations to set forth a program to address Regional Haze visibility impairment. The Regional Haze final rule was published in the Federal Register on

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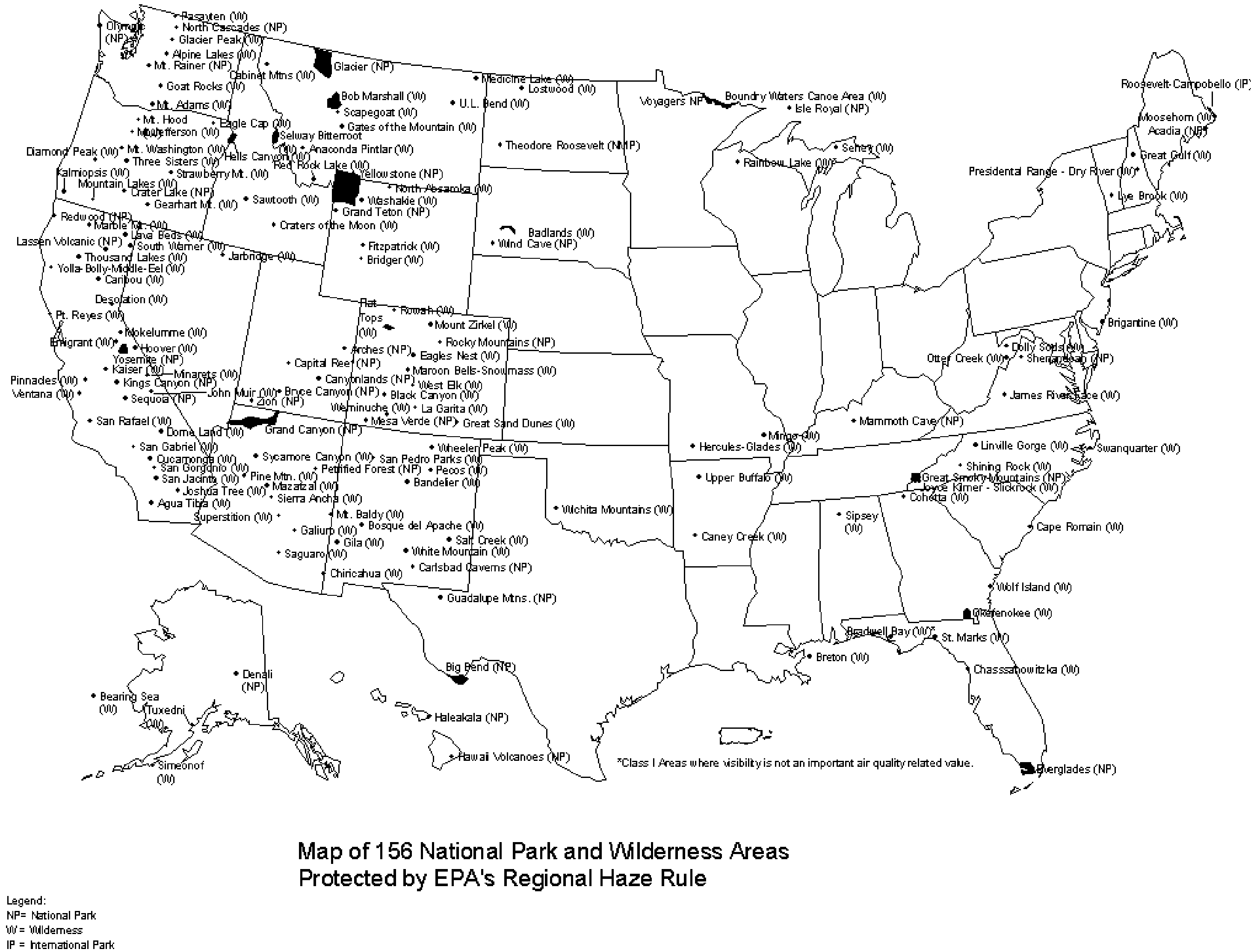
[2] 64 FR 35713.

[3] Only two of the 158 mandatory Class I areas currently do not have visibility air quality related values (AQRVs): Rainbow Lakes in northwest Wisconsin and Bradwell Bay in Florida ("New Source Review Workshop Manual (DRAFT)," U.S. EPA, Table E-1, October 1990).

[4] 45 FR 80084 (December 2, 1980) and 40 CFR 51 Subpart P – Protection of Visibility.

July 1, 1999. The BART guidelines proposed rule was published in the Federal Register on July 20, 2001.

Figure 3-1. Map of 156 National Park and Wilderness Areas Protected by EPA's Regional Haze Rule



3.2 *40 CFR Part 51 Subpart P – Protection of Visibility*

3.2.1 Coordination of 1980 Visibility Rules and 1999 Regional Haze Rules

The 1980 visibility rules promulgated in 40 CFR Part 51 Subpart P were revised in 1999 to incorporate the 1999 Regional Haze rules. Table 3-1 below summarizes the amendments made to this regulatory subpart to coordinate the requirements of the Regional Haze rule with the1980 visibility regulations.

Table 3-1
1999 Regional Haze Amendments Made to the 1980 Visibility Rules in 40 CFR Part 51

Section	Amendment
51.300 Purpose and Applicability	Amended to clarify that Subpart P includes provisions for Regional Haze as well as reasonably attributable visibility impairment.
51.301 Definitions	Added the following terms: reasonably attributable visibility impairment, Regional Haze, deciview, State, most impaired days, least impaired days, implementation plan, Indian tribe, BART-eligible source, and geographic enhancement. Revised the following terms: Federal Land Manager, major stationary source, natural conditions, and visibility impairment.
51.302 Implementation Control Strategies	Changed references to the administrative process requirements for public hearings and SIP submissions. Amended to clarify that the implementation control strategies apply to reasonably attributable visibility impairment.
51.303 Exemptions	No changes were made to this section in the 1999 amendments to the rule.
51.304 Integral Vistas	No changes were made to this section in the 1999 amendments to the rule.
51.305 Monitoring	Amended to clarify that the monitoring requirements apply to reasonably attributable visibility impairment.
51.306 Long-term Strategy	Amended to clarify that the long-term strategy requirements apply to reasonably attributable visibility impairment. Revised the periodic review and revision schedule
51.307 New Source Review	Amended to clarify that the new source review requirements apply to reasonably attributable visibility impairment. Revised the periodic review and revision schedule.
51.308 Regional Haze Program Requirements	New section to establish requirements for implementation plans, plan revisions, and periodic progress reviews to address Regional Haze.
51.309 Requirements Related to the Grand Canyon Visibility Transport Commission	New section to establish the requirements for the first Regional Haze implementation plan to address Regional Haze visibility impairment in the 16 Class I areas covered by the Grand Canyon Visibility Transport Commission Report.

Sections 3.2.2 through 3.2.5 of this report summarize rule Sections 40 CFR 51.300, 51.301, 51.308, and 51.309. The requirements in 40 CFR Sections 51.302 through 51.307 relate primarily to the reasonably attributable visibility impairment rules originally promulgated in

1980. A summary and discussion of how these provisions relate to BART at the taconite facilities is included in Attachment E.

3.2.2 40 CFR 51.300 Purpose and Applicability

A primary purpose of the rule is to require states to develop programs to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in Class I areas which impairment results from manmade air pollution. The rule establishes requirements addressing visibility impairment in its two principal forms: "reasonably attributable" impairment (i.e., impairment attributable to a single source/small group of sources) and Regional Haze (i.e., widespread haze from a multitude of sources which impairs visibility in every direction over a large area).

The requirements for implementation plans to address reasonably attributable visibility impairment are applicable to each state with a Class I area (35 states, including Minnesota, and the Virgin Islands). The rule requirements for implementation plans to address Regional Haze visibility impairment are applicable to each state in which the emissions from any source may reasonably be anticipated to cause or contribute to visibility impairment (all states, including Minnesota).

How does this provision relate to BART at taconite facilities?

This provision identifies Minnesota as a state subject to the rule and establishes the requirement that the MPCA must develop an implementation plan to address both reasonably attributable visibility impairment and Regional Haze visibility impairment. As detailed in Section 3.2.4, the Regional Haze implementation plan will contain BART limitations for BART-eligible sources.

3.2.3 40 CFR 51.301 Definitions

This section establishes the definitions of terms for the rule.

How does this provision relate to BART at taconite facilities?

A "BART-eligible source" is defined as an "existing stationary facility." An "existing stationary facility" is any facility that meets certain source category, timing, and emissions criteria. Taconite ore processing facilities are one of the 26 source categories listed in this definition. See Section 4.2 for additional details of BART applicability to taconite ore processing facilities.

3.2.4 40 CFR 51.308 Regional Haze Program Requirements

3.2.4.1 Purpose

This new section in 40 CFR 51, subpart P, establishes implementation plans requirements to address Regional Haze. This section is divided into the following subsections:

1. Schedule for implementation plans,
2. Regional planning,
3. Core requirements for the Regional Haze implementation plan,

4. BART requirements for Regional Haze visibility impairment,
5. Requirements for comprehensive periodic revisions of implementation plans for Regional Haze,
6. Requirements for periodic reports describing progress towards the reasonable progress goals,
7. Determination of the adequacy of existing implementation plan, and
8. Requirements for State and FLM coordination.

3.2.4.2 Schedule for Implementation Plans

Each state must submit an implementation plan meeting the core requirements for the Regional Haze implementation plan and the BART requirement for Regional Haze visibility (described in Sections 3.2.4.4 and 3.2.4.5, respectively) by the following dates:

- For any area designated as attainment or unclassifiable for the national ambient air quality standard (NAAQS) for fine particulate matter (PM2.5), the state must submit a Regional Haze implementation plan to EPA within 12 months after the date of designation.

- For any area designated as nonattainment for the PM2.5 NAAQS, the state must submit a Regional Haze implementation plan to EPA at the same time that the state's plan for implementation of the PM2.5 NAAQS must be submitted, that is, within 3 years after the area is designated as nonattainment, but not later than December 31, 2008.

This schedule is summarized in Table 3-3.

How does this provision relate to BART at taconite facilities?

This provision establishes the timeline for SIP submittal by the MPCA, which is dependent on the date of $PM_{2.5}$ designation by EPA and the designation status in northern Minnesota.

In a memo to the regional administrators[5], EPA requests a list of recommended $PM_{2.5}$ designations from states and tribes by February 15, 2004. It is EPA's policy to use the most recent three years of data available at the time of the designations; because EPA plans to promulgate final designations on December 15, 2004, it intends to consider the 2001 to 2003 data in making those designations. The EPA plans to announce its intended designations in July 2004 and will provide 120 days for states and tribes to comment. The EPA plans to publish final $PM_{2.5}$ designations for all areas on December 15, 2004. The EPA intends to propose and finalize the $PM_{2.5}$ implementation rule by September 2004, prior to issuing final designations, so that the implementation rule may be taken into consideration during the designation process.

Initial $PM_{2.5}$ ambient monitoring data have been collected at 22 sites in Minnesota[6] from April 1999 to September 2000. Based on these initial monitoring results, none of the sites exceed the new $PM_{2.5}$ standard, although two sites in St. Paul are close to the annual average standard.

[5] EPA memo to the Regional Administrators: "Designations for the Fine Particle National Ambient Air Quality Standards," April 1, 2003.
[6] From MPCA's 2001 legislative report, "Air Quality in Minnesota: Problems and Approaches," Appendix B.

While it is too early to determine trends with less than two years of $PM_{2.5}$ sampling, based on the existing data, it appears that the first Regional Haze SIP will be due December 15, 2005.

Table 3-2 provides an anticipated timeline for compliance with individual BART limitations based on the information provided above.

Table 3-2
Anticipated Timeline for Compliance with BART Requirements

Date	Item
February 15, 2004	MPCA $PM_{2.5}$ designation recommendations due to EPA
April 15, 2004	Deadline for EPA to sign a notice of proposed rulemaking revising BART regulations and guidelines*
July 15, 2004	EPA announces intended $PM_{2.5}$ designations
October 15, 2004	Comments due to EPA regarding recommended $PM_{2.5}$ designations
December 15, 2004	EPA publishes final $PM_{2.5}$ designations
April 15, 2005	Deadline for EPA to sign a notice of final rulemaking revising BART regulations and guidelines*
December 15, 2005	MPCA's Regional Haze SIP due for areas designated attainment for $PM_{2.5}$
December 15, 2007	Following public notice and comment period, EPA approves MPCA's Regional Haze SIP
December 15, 2012	Compliance with BART required

* See Section 4.3.3 of this report. EPA must also submit the notices of proposed and final rulemaking to the Office of Federal Register no later than five days following signature.

3.2.4.3 Regional Planning

If a state chooses to participate in a regional planning process, it may defer addressing the core requirements for Regional Haze and the requirements for BART. If a state opts to do this, it must: (1) submit an implementation plan demonstrating its commitment to regional planning by the earliest date by which an implementation plan would be due for any area of the state, and (2) submit an implementation plan revision addressing the Regional Haze and BART requirements by the latest date an area within the planning region would be required to submit an implementation plan, but not later than December 31, 2008. The timeline for such SIP submittals are presented in Table 3-3.

Table 3-3
Timeline for First Regional Haze SIP Submittal by Area Designation

Area Designation	Due Date of First Regional Haze SIP
Attainment or unclassifiable for $PM_{2.5}$	1 yr after EPA publishes designation (~2004-2006)
Nonattainment for $PM_{2.5}$	Same time $PM_{2.5}$ SIPs are due (3 yrs after EPA publishes designation (~2006-2008)
Multistate regional planning for combined attainment and non-attainment	Phase I: commitment to regional planning SIP – due 1 year after EPA publishes first designation for any area within the state Phase II: complete Regional Haze SIP - due same time $PM_{2.5}$ SIPs are due; 3 years after EPA publishes designation (~2006-2008)

How does this provision relate to BART at taconite facilities?

This provision establishes the requirements and timeline the MPCA must follow if it chooses to defer addressing the core requirements for Regional Haze and BART if the state is participating in a regional planning process.

The MPCA is currently participating in the Central Regional Air Planning Association (CenRAP) process to develop a Regional Haze SIP. CenRAP is an organization of states, tribes, federal agencies and other interested parties that identifies Regional Haze and visibility issues and develops strategies to address them. CenRAP is one of the five Regional Planning Organizations (RPOs) across the U.S. and includes the states and tribal areas of Minnesota, Iowa, Nebraska, Missouri, Kansas, Arkansas, Oklahoma, Louisiana, and Texas. CenRAPs goals are as follows:

- Promote policies that ensure fair and equitable treatment of all participating members,
- Provide coordination of science and technology to support air quality policy issues in the central region,
- Recommend strategies on air quality issues for use by member states and tribes in developing implementation programs, regulations and laws, and
- Conduct research and undertake other activities as necessary for information to support the development of sound state and tribal air pollution policies.

3.2.4.4 Core requirements for the Regional Haze implementation plan

The state must address Regional Haze in each Class I area located within the state and in each Class I area located outside the state which may be affected by emissions from within the state. To meet the core requirements for Regional Haze for these areas, the state must submit an implementation plan containing the following elements and supporting documentation for all required analyses:

- Reasonable progress goals (expressed in deciviews) for each Class I area located within the state that for achieving natural visibility conditions. The goals must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period.

- Calculations of baseline and natural visibility conditions (expressed in deciviews) for each Class I area located within the state.

- Long-term strategy for Regional Haze that addresses Regional Haze visibility impairment for each Class I area within the state and for each Class I area located outside the state which may be affected by emissions from the state. The long-term strategy must include enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals.

- Monitoring strategy and other implementation plan requirements for measuring, characterizing, and reporting of Regional Haze visibility impairment that is representative of all Class I areas within the state.

How does this provision relate to BART at taconite facilities?

This provision requires the MPCA to submit a SIP containing the following core requirements for the Regional Haze SIP:

1. Reasonable progress goals;
2. Calculations of baseline and natural visibility conditions;
3. Long-term strategy for Regional Haze; and
4. Monitoring strategy and other implementation plan requirements.

3.2.4.5 BART requirements for Regional Haze visibility impairment

The state must submit an implementation plan containing emission limitations representing BART and schedules for compliance with BART for each BART-eligible source that may reasonably be anticipated to cause or contribute to any impairment of visibility in any Class I area, unless the state demonstrates that an emissions trading program or other alternative will achieve greater reasonable progress toward natural visibility conditions. To address the requirements for BART, the state must submit an implementation plan containing the following elements and include documentation for all required analyses:

- A list of all BART-eligible sources within the state.

- A determination of BART for each BART-eligible source in the state that emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any Class I area. All such sources are subject to BART.

- If technological or economic limitations on the applicability of measurement methodology to a particular source would make an emission standard infeasible, the state may prescribe a design, equipment, work practice, or other operational standard, to require the application of BART. The emission standard establishes the emission reduction to be achieved by implementation of such alternative, and must provide for compliance by means which achieve equivalent results.

- A requirement that each source subject to BART be required to install and operate BART as expeditiously as practicable, but not later than 5 years after approval of the implementation plan revision.

- A requirement that each source subject to BART maintain the required control equipment and establish procedures to ensure such equipment is properly operated and maintained.

A state may opt to implement an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain BART. To do so, the state must demonstrate that the emissions trading program or other alternative measure will achieve greater reasonable progress than would be achieved through the installation and operation of BART. To make this demonstration, the state must submit an implementation plan containing the following plan elements and include documentation for all required analyses:

- A demonstration that the emissions trading program or other alternative measure will achieve greater reasonable progress than would have resulted from the installation and operation of BART at all sources subject to BART in the state.

- A demonstration that the emissions trading program or alternative measure will apply, at a minimum, to all BART-eligible sources in the state. Sources having a federally enforceable emission limitation meeting BART do not need to meet the requirements of the emissions trading program or alternative measure.

- A requirement that all necessary emission reductions take place during the period of the first long-term strategy for Regional Haze.

- A demonstration that the emission reductions resulting from the emissions trading program or other alternative measure will be surplus to those reductions resulting from measures adopted to meet requirements of the CAA as of the baseline date of the SIP.

After a state has met the requirements for BART or implemented emissions trading program or other alternative measure that achieve more reasonable progress than the installation and operation of BART, BART-eligible sources will be subject to the core requirements for the Regional Haze implementation plan described above.

Any BART-eligible facility required to install, operate, and maintain BART may apply to the Administrator for an exemption from that requirement, subject to the exemptions from control requirements described above.

How does this provision relate to BART at taconite facilities?

This provision requires the MPCA to submit a SIP containing emission limitations representing BART and schedules for compliance with BART for each BART-eligible source that may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I area, unless it demonstrates that an emissions trading program or other alternative will achieve greater reasonable progress toward natural visibility conditions.

This provision requires taconite facilities to determine BART for each BART-eligible source that emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any Class I area, unless the state has demonstrated that an emissions trading program or other alternative will achieve greater reasonable progress toward natural visibility conditions. For each source subject to BART, the facilities will be required to install and operate BART as expeditiously as practicable, but not later than 5 years after approval of the implementation plan revision.

In the event that the MPCA opts to implement an emissions trading program or other alternative measure rather than require sources subject to BART to install, operate, and maintain BART, this provision requires the Agency to submit a SIP to demonstrate that this emissions trading program or other alternative measure will achieve greater reasonable progress than would be achieved through the installation and operation of BART.

3.2.4.6 Requirements for comprehensive periodic revisions of implementation plans for Regional Haze

Each state must revise and submit its Regional Haze implementation plan revision to EPA by July 31, 2018 and every ten years thereafter. In each plan revision, the state must evaluate and reassess all of the elements required in the Regional Haze implementation plan, taking into account improvements in monitoring data collection and analysis techniques, control technologies, and other relevant factors. In evaluating and reassessing these elements, the state must address the following:

- Current visibility conditions for the most impaired and least impaired days, and actual progress made towards natural conditions during the previous implementation period. The period for calculating current visibility conditions is the most recent five-year period preceding the required date of the implementation plan submittal for which data are available. Current visibility conditions must be calculated based on the annual average level of visibility impairment for the most and least impaired days for each of these five years. Current visibility conditions are the average of these annual values.

- The effectiveness of the long-term strategy for achieving reasonable progress goals over the prior implementation period(s); and

- Affirmation of, or revision to, the reasonable progress goal.

How does this provision relate to BART at taconite facilities?

This provision requires the MPCA to revise and submit its Regional Haze SIP revision to EPA by July 31, 2018 and every ten years thereafter. The provision establishes the elements the MPCA must address in each plan revision. Although not specifically stated, this provision may be interpreted to require facilities to reevaluate BART every 10 years.

3.2.4.7 Requirements for periodic reports describing progress towards the reasonable progress goals

Each state must submit a report to the Administrator every 5 years evaluating progress towards the reasonable progress goal for each Class I area located within the state and in each Class I area located outside the state which may be affected by emissions from within the state. The first progress report is due 5 years from submittal of the initial implementation plan.

How does this provision relate to BART at taconite facilities?

This provision relates to MPCA and as such does not directly relate to BART at taconite facilities.

3.2.4.8 Determination of the adequacy of existing implementation plan

At the same time the state is required to submit any 5-year progress report, the state must also determine the adequacy of existing implementation plan and take action based upon the information presented in the progress report:

1. If the MPCA determines that the existing SIP requires no further revision in order to achieve established goals for visibility improvement and emissions reductions, it must provide to the EPA a negative declaration that further revision is not needed at this time.
2. If the MPCA determines that the SIP is or may be inadequate to ensure reasonable progress due to emissions from sources in another state(s) which participated in a regional planning process, it must provide notification to the EPA and to the other state(s) which participated in the regional planning process with the states. The MPCA must also collaborate with the other state(s) to develop additional strategies to address the plan's deficiencies.
3. Where the MPCA determines that the SIP is or may be inadequate to ensure reasonable progress due to emissions from sources in another country, it must provide notification to the EPA.
4. Where the MPCA determines that the SIP is or may be inadequate to ensure reasonable progress due to emissions from sources within the state, it must revise its SIP to address the plan's deficiencies within one year.

How does this provision relate to BART at taconite facilities?

This provision relates to MPCA and as such does not directly relate to BART at taconite facilities.

3.2.4.9 Requirements for State and Federal Land Manager coordination

By November 29, 1999, the state must have identified in writing to the FLMs the title of the official to which the FLM can submit recommendations on the implementation Regional Haze program requirements. The state must provide the FLM with an opportunity for consultation on an implementation plan (or plan revision) for Regional Haze. The state must include a description in any implementation plan (or plan revision) of how it addressed any comments provided by the FLMs. The plan (or plan revision) must provide procedures for continuing consultation between the state and FLM on the implementation of the visibility protection program.

How does this provision relate to BART at taconite facilities?

This provision establishes the required coordination between the MPCA and the FLMs. This provision relates to MPCA and as such does not directly relate to BART at taconite facilities.

3.2.5 40 CFR 51.309 Requirements for the GCVTC

This section establishes the requirements for the first Regional Haze implementation plan to address Regional Haze visibility impairment in the 16 Class I areas covered by the Grand Canyon Visibility Transport Commission (GCVTC) report.

How does this provision relate to BART at taconite facilities?

The Class I areas that are relevant to the taconite industry in Minnesota are not expected to be among the 16 Class I areas in the southwest United Stated covered by the GCVTC report. Therefore, this provision has no direct implication on the implementation of BART at taconite facilities.

3.3 *Status of Minnesota Implementation Plan for Visibility Protection*

Per 40 CFR 52.1236, the MPCA has not addressed visibility protection to EPA's satisfaction, so 40 CFR 52.26, 52.28, and 52.29 are incorporated. While Minnesota does not have a visibility protection plan[7] that meets CAA Section 169a, the MPCA recognizes Regional Haze as an emerging issue that will necessitate implementation plan revisions[8]. Based on a review of the Minnesota SIP as summarized on 52.1220, no implementation plan documents have been submitted to the EPA concerning visibility.

3.4 *Implementation of the Regional Haze Program in Indian Country*

This section discusses how the requirements of the Regional Haze rule relate to emissions released from Indian Country.

3.4.1 Background on Tribal Air Quality Programs

On November 8, 1984, EPA released a policy statement entitled "EPA Policy for the Administration of Environmental Programs on Indian Reservations." Under this policy, EPA will pursue the principle of Indian "self-government" and work with tribal governments on a "government-to-government" basis. The CAA, as amended in 1990, added a new section authorizing EPA to "treat tribes as states" for the purposes of administering CAA programs. The section required EPA to promulgate regulations listing specific CAA provisions for which it would be appropriate to treat tribes as states. These regulations are codified as 40 CFR part 49, generally referred to as the Tribal Authority Rule (TAR). The section also required EPA to

[7] Per 40 CFR 52.1236(a)-(c).
[8] Minnesota State Implementation Plan, 2002 Update. See http://www.pca.state.mn.us/air/sip.html.

provide alternative means to ensure air quality protection in cases where it determines that treating tribes as "identical" to states would be inappropriate. In promulgating the TAR, EPA provided flexibility to tribes seeking to implement the CAA with the decision not to treat tribes as states for certain provisions of the CAA. For example, unlike states, tribes are not required by the TAR to adopt and implement CAA plans or programs and therefore are not subject to statutory deadlines for submittal of implementation plans.

3.4.2 Issues Related to the Regional Haze Program in Indian Country

The requirements of the Regional Haze rule are among those Federal air quality programs for which tribes may be determined eligible and receive authorization to implement under the TAR. Tribes wishing to participate in the Regional Haze program and be "treated as states" may seek approval but are not required to do so. Where tribes do not take on this responsibility, EPA will ensure air quality protection in Indian country consistent with TAR.

In order to encourage tribes to participate, the TAR provides flexibility of submitting programs as they are developed, rather than in accordance with statutory deadlines. This means that tribes may take additional time as necessary to submit implementation plans for Regional Haze beyond the deadlines established in the rule.

How does this provision relate to BART at taconite facilities?
An Indian tribe may wish to participate in a state or regional planning effort for Regional Haze or develop its own self-sufficient Regional Haze program through an implementation plan referred to as a tribal implementation plan (TIP). The EPA is encouraging the consideration of impacts on visibility in tribal locations in regional planning efforts.

In Minnesota, there are 11 Indian reservations or communities – seven Anishinaabe (Chippewa, Ojibwe) reservations and four Dakota (Sioux) communities (see Figure 3-2 for locations).[9] The seven Anishinaabe reservations include:

1. Grand Portage located in the northeast corner of the state,
2. Bois Forte located in extreme northern Minnesota,
3. Red Lake located in extreme northern Minnesota west of Bois Forte,
4. White Earth located in northwestern Minnesota,
5. Leech Lake located in the north central portion of the state,
6. Fond du Lac located in northeast Minnesota west of the city of Duluth, and
7. Mille Lacs located in the central part of the state, south and east of Brainerd.

The four Dakota Communities are in central and southern Minnesota and include: Shakopee Mdewakanton located south of the Twin Cities near Prior Lake; Prairie Island located near Red Wing; Lower Sioux located near Redwood Falls; and Upper Sioux located near the city of Granite Falls.

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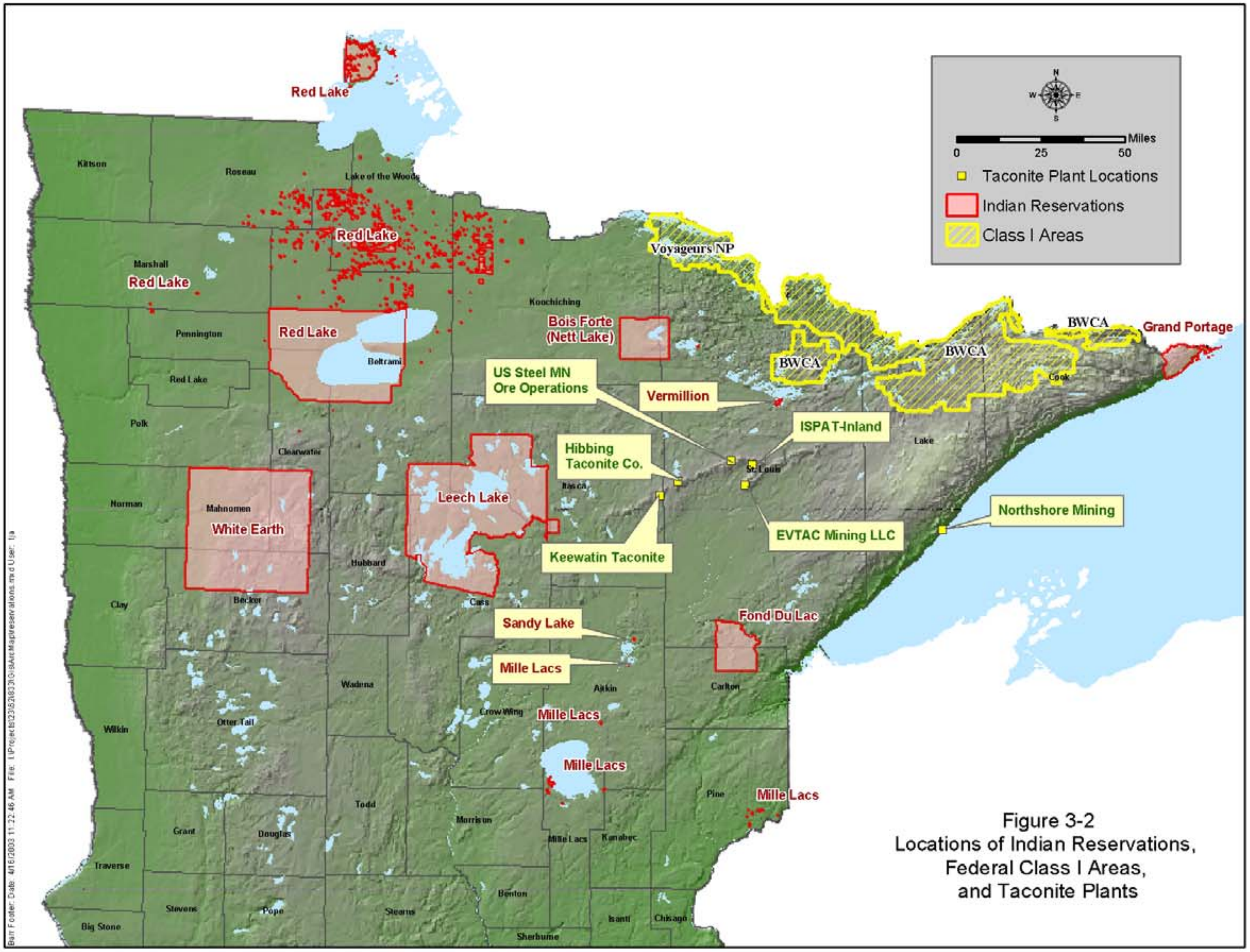
[9] Information from the Minnesota Indian Affairs Council at http://www.indians.state.mn.us/tribes.html.

Figure 3-2. Locations of Indian Reservations, Federal Class I Areas, and Taconite Plants



4 Summary of BART Guidelines Proposed Rule

The information provided in this section is based on EPA's July 20, 2001 "Proposed Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations; Proposed Rule."[10] See Attachment F for a copy of the Federal Register notice. Section 4.1 provides context to the BART requirements as they relate to the CAA requirements. Section 4.2 details the BART requirements and Section 4.3 outlines the current legal challenges to the BART guidelines rulemaking.

4.1 *Background*

EPA included in the final Regional Haze rule, published on July 1, 1999, a requirement for BART for certain large stationary sources put in place between 1962 and 1977. In addition, Section 169a(b)(1) of the CAA requires EPA to provide guidelines to states on the implementation of the visibility program. The July 20, 2001 proposed BART rule would require states to use the guidelines for all of the 26 industry source categories.

4.2 *Guidelines for BART Determinations Under the Regional Haze Rule*

4.2.1 Overview

Section 169a(b)(2)(A) of the CAA requires states to require certain existing stationary sources to install BART. The BART requirement applies to major stationary sources from one of 26 identified source categories which have the potential to emit 250 tons per year or more of any air pollutant. The CAA requires sources which were put in place between August 7, 1962 and August 7, 1977 to install BART. The CAA requires BART when any source meeting the above description emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any Class I area. The CAA further requires states to make BART emission limitations part of their SIPs.

In the July 1, 1999 rulemaking, EPA added a BART requirement for Regional Haze. The Regional Haze rule codifies and clarifies the BART provisions in the CAA. The rule requires states to identify and list BART-eligible sources. The next step is to identify those BART-eligible sources that may "emit any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility." A source which fits this description is "subject to BART." For each source subject to BART, states must identify the level of control representing BART (if any). Then it must establish an emission limit representing BART and ensure compliance with that requirement no later than 5 years after EPA approves the SIP.

States have the option of using an alternative measure, such as an emissions trading program, to impose controls on a case-by-case basis for each source subject to BART. However, if states choose this option, they must provide a demonstration that the alternative will achieve greater

[10] 66 FR 38108.

"reasonable progress" than would have resulted from installation of BART. States are required to include in their SIPs details on how they would implement the alternative measure.

The guidelines provide procedures states must use in implementing the Regional Haze BART requirements on a source-by-source basis. The guidelines address general topics related to development of a trading program or other alternative, but most of the details of guidance for trading programs will be addressed in separate rulemakings or policy documents. The BART analysis process is as follows:

- Identification of all BART-eligible sources,
- Identification of sources subject to BART,
- Engineering analysis,
- Cumulative air quality analysis,
- Emissions limits, and
- General considerations in establishing a trading program alternative.

The guidelines are written primarily for the benefit of state, local, and tribal agencies to satisfy the requirements for including the BART determinations and emission limitations in their SIPs or tribal implementation plans (TIPs).

4.2.2 How to Identify BART-Eligible Sources

This section details the four steps to identify BART-eligible sources[11]. A BART-eligible source is an existing stationary source in 26 listed categories which meets criteria for startup dates and potential emissions.

Step 1: Identify the emission units in BART categories.
The BART requirement only applies to sources in 26 specific categories listed in the CAA. The listed categories are:

1. Fossil-fuel fired steam electric plants of more than 250 million British thermal units (BTU) per hour heat input,
2. Coal cleaning plants (thermal dryers),
3. Kraft pulp mills,
4. Portland cement plants,
5. Primary zinc smelters,
6. Iron and steel mill plants,
7. Primary aluminum ore reduction plants,
8. Primary copper smelters,

[11] See also Section 5.7.1 for a discussion of the MPCA BART survey.

9. Municipal incinerators capable of charging more than 250 tons of refuse per day,
10. Hydrofluoric, sulfuric, and nitric acid plants,
11. Petroleum refineries,
12. Lime plants,
13. Phosphate rock processing plants,
14. Coke oven batteries,
15. Sulfur recovery plants,
16. Carbon black plants (furnace process),
17. Primary lead smelters,
18. Fuel conversion plants,
19. Sintering plants,
20. Secondary metal production facilities,
21. Chemical process plants,
22. Fossil-fuel boilers of more than 250 million BTUs per hour heat input,
23. Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels,
24. Taconite ore processing facilities,
25. Glass fiber processing plants, and
26. Charcoal production facilities.

For Step 1, identify all of the emissions units at the plant that fit into one or more of the listed categories. At taconite plants, it is likely that there will be little confusion in how to classify emission units into their source categories, since most emission units at these plants can be classified into the "taconite ore processing facilities" source category.

<u>Step 2: Identify the start-up dates of those emission units.</u>
Emissions units listed under Step 1 are BART-eligible only if they were "in existence" on August 7, 1977 but were not "in operation" before August 7, 1962. "In existence" means the same thing as the term "commence construction" as that term is used in the PSD regulations. "In operation" is defined as "engaged in activity related to the primary design function of the source." This means that a source must have begun actual operations by August 7, 1962 to satisfy the BART eligibility requirement.

The definition of BART-eligible facility includes sources that were in operation before August 7, 1962, but were reconstructed during August 7, 1962 to August 7, 1977. A reconstruction has taken place if "the fixed capital cost of the new component exceeds 50 percent of the fixed capital cost of a comparable entirely new source," the same policies and procedures for identifying reconstructed "affected facilities" under the New Source Performance Standard (NSPS) program. Similarly, if an emission unit has undergone reconstruction that commenced after August 7, 1977, it is not BART-eligible.

The BART provision in the Regional Haze rule contains no explicit treatment of modifications. EPA believes the best interpretation for purposes of the visibility provisions is that modified emissions units are still "existing." If a modification to an emissions unit which began operation within the 1962 to 1977 time frame was a major modification subject to the BACT, LAER, or NSPS levels of control, the review process will take into account that this level of control is already in place and may find that the level of controls are already consistent with BART.

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

The result of Steps 1 and 2 is a list of emissions units at a given plant site that are within one or more of the BART categories and that were placed into operation within the 1962 to 1977 time frame. The third step is to determine whether the total emissions represent a current potential to emit that is greater than 250 tons per year of any single visibility impairing pollutant. In most cases, total emissions are calculated as the sum of potential emissions from all emission units on the list resulting from Steps 1 and 2. In a few cases, a determination was made as to whether the plant contained more than one "stationary source", explained further below.

Visibility-impairing pollutants include the following:

- Sulfur dioxide (SO2),
- Nitrogen oxides (NOx),
- Particulate matter,[12]
- Volatile organic compounds (VOC), and
- Ammonia.

The definition of potential to emit is identical to that in the PSD program. This means that a source which actually emits less than 250 tons per year of a visibility-impairing pollutant is BART-eligible if its emissions would exceed 250 tons per year when operating at its maximum physical and operational design. A source's "potential to emit" may take into account federally enforceable emission limits.

The Regional Haze rule defines a stationary source as a "building, structure, facility or installation which emits or may emit any air pollutant." The rule further defines "building, structure or facility" as: all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). These plant boundary issues and "common control" issues are very similar to those already addressed in implementation of the Title V operating permits program (see 40 CFR 70) and in new source review (see 40 CFR 52.21). For purposes of the Regional Haze rule, group emissions from all emission units put in place within the 1962 to 1977 time frame that are within the 2-digit SIC code, even if those emission units are in different categories on the BART category list. Taconite plants may have emission units classified outside the taconite ore processing source category and fit in another BART category (e.g., fossil-fuel boilers of more than 250 million BTUs per hour heat input). Therefore, taconite companies should ensure that the stationary source(s) is defined appropriately for determining BART eligibility of its emission units.

[12] 66 FR 38119. PM_{10} may be used as the indicator for particulate matter. EPA does not recommend using total suspended solids. PM_{10} emissions include the components of $PM_{2.5}$ as a subset.

Step 4: Identify the emissions units and pollutants that constitute the BART-eligible source.
If the emissions from the list of emissions units at a stationary source exceed a potential to emit of 250 tons per year for any visibility-impairing pollutant, then that collection of emissions units is a BART-eligible source. A BART analysis is required for each visibility-impairing pollutant emitted.

4.2.3 How to Identify Sources "Subject to BART"

After identifying the BART-eligible sources, the next step is determining whether these sources are subject to a further BART analysis because they emit "an air pollutant which may reasonably be anticipated to cause or contribute" to any visibility impairment in a Class I area. A BART-eligible source is "reasonably anticipated to cause or contribute" to Regional Haze if the source emits pollutants within a geographic region from which pollutants can be emitted and transported downwind to a Class I area.

EPA states, in general, that geographic "regions" that can contribute to Regional Haze generally extend for hundreds or thousands of kilometers. Because the taconite plants in Minnesota are located in relative close proximity to Class I areas, BART-eligible sources at these plants are initially presumed to be subject to BART.

4.2.4 Engineering Analysis of BART Options

In the Regional Haze rule, the BART analysis is divided into two parts: an engineering analysis requirement and a visibility impacts analysis requirement. This section of the guidelines addresses the requirements for the engineering analysis. The requirements for a visibility impacts analysis are discussed in Section 4.2.5.

The engineering analysis identifies the best system of continuous emission reduction taking into account:

- The available retrofit control options,
- Any pollution control equipment in use at the source,
- The costs of compliance with control options,
- The remaining useful life of the facility, and
- The energy and non-air quality environmental impacts of control options.

In the proposed guidelines, EPA seeks comment on two alternative approaches for conducting a BART engineering analysis. Under the first approach, the BART analysis would be very similar to the BACT review using a "top-down" approach. The BART engineering analysis would be a process which ranks all available control technologies in descending order of control effectiveness. Under this option, the most stringent alternative must be examined first. That alternative is selected as the "best" unless demonstrated that the alternative cannot be justified based upon technical considerations, costs, energy impacts, and non-air quality environmental impacts. If the most stringent technology is eliminated in this fashion, the next most stringent alternative is then considered, and so on. The "top-down" approach is similar to the existing requirements for the Best Available Control Technology (BACT) in EPA's New Source Review rules at 40 CFR 52.21. The second approach provides more choices in the way the BART analysis is structured. For example, the BART determination process could begin with the evaluation of the least stringent technically feasible control option or an intermediate control option drawn from the range of technically feasible control alternatives. Then the additional emission reductions, costs, and other effects (if any) of successively more stringent control options would be considered.

While both approaches require essentially the same parameters and analyses, the EPA prefers the first approach, because it may be more straightforward to implement than the alternative and would tend to give more thorough consideration to stringent control alternatives. As a result, the BART screening evaluation in Section 7 is performed using the "top-down" approach.

Although very similar in process, BART reviews differ in several respects from the BACT review process, as described in Table 4-1.

Table 4-1
BART Review vs. BACT Review

BART Review	BACT Review
Applies to existing sources, which affects available controls and the impacts of those controls	Applies to new sources, which affects available controls and the impacts of those controls
State must take into account the "cost of compliance, the remaining useful life of the source, the energy and non-air quality environmental impacts of compliance, any existing pollution control technology in use at the source, and the degree of improvement in visibility from the use of such technology"	Permitting authority must consider the "energy, environmental and economic impacts and other costs" associated with a control technology
Because of the differences in terminology, the BART review process tends to encompass a narrower range of factors (e.g., "non-air quality environmental impacts")	Because of the differences in terminology, the BACT review process tends to encompass a broader range of factors (e.g., "environmental impacts")
No requirement in the BART engineering analysis to evaluate adverse air quality impacts of control alternatives such as the relative impacts on hazardous air pollutants	Requirement in the BACT engineering analysis to evaluate adverse air quality impacts of control alternatives such as the relative impacts on hazardous air pollutants
No minimum level of control required	BACT emission limitation must be at least as stringent as any NSPS that applies to the source

Once a source is determined to be subject to BART, then a BART review is required for each visibility-impairing pollutant emitted. In a BART review, BART must be established for each pollutant that can impair visibility for each affected emission unit. Consequently, the BART determination must address air pollution control measures for each emissions unit or pollutant emitting activity subject to review.

The five basic steps of a case-by-case BART engineering analysis are:

Step 1: Identify all available retrofit control technologies,
Step 2: Eliminate technically infeasible options,
Step 3: Rank remaining control technologies by control effectiveness,
Step 4: Evaluate impacts and document the results, and
Step 5: Select "best system of continuous emission reduction."

These steps are detailed in the taconite industry BART screening evaluation presented in Section 7 of this report.

4.2.5 Cumulative Air Quality Analysis

The Regional Haze rule requires the following in 40 CFR 51.308(e)(1)(ii)(B):

> An analysis of the degree of visibility improvement that would be achieved in each mandatory Class I Federal area as a result of the emission reductions from all sources subject to BART located within the region that contributes to visibility impairment in the Class I area, based on the… [results of the engineering analysis required by 40 CFR 51.308(e)(1)(ii)(A)].

A regional modeling analysis is required to address the total cumulative regional visibility improvement if all sources subject to BART were to install the "best" controls selected according to the engineering analysis described above in Section 4.2.4.

The regional modeling analysis is used to assess the cumulative impact on visibility of the controls selected in the engineering analysis for the time period for the first Regional Haze SIP, that is, the time period between the baseline period and the year 2018. This cumulative impact assessment is used to determinate whether the controls identified provide sufficient visibility improvement to justify their installation. There is sufficient basis for the controls if it is demonstrated for any Class I area that any of the following criteria are met:

1. The cumulative visibility improvement is a substantial fraction of the achievable visibility improvement from all measures included in the SIP, or is a substantial fraction of the visibility goal selected for any Class I area; or
2. The cumulative visibility improvement is necessary to prevent any degradation from current conditions on the best visibility days. The visibility SIP must provide for BART emission limitations for all sources subject to BART, unless it is demonstrated that no BART controls are justifiable based upon the cumulative visibility analysis.

4.2.6 Enforceable Limits / Compliance Date

To complete the BART process, enforceable emission limits must be established and compliance is required within a given period of time. In particular, an enforceable emission limit must be established for each emission unit and each pollutant subject to review. In addition, compliance with the BART emission limitations must be required no later than 5 years after EPA approves the SIP. If technological or economic limitations in the application of a measurement methodology to a particular emission unit would make an emissions limit infeasible, a design, equipment, work practice, operation standard, or combination of these types of standards may be prescribed.

Because the BART requirements are "applicable" requirements of the CAA, they must be included as Title V permit conditions. The CAA requires emissions limits such as BART to be met on a continuous basis. Although the CAA does not necessarily require the use of continuous emissions monitors (CEMs), it is important that sources employ techniques that ensure compliance on a continuous basis. Monitoring requirements generally applicable to sources, including those that are subject to BART, are governed by other regulations (e.g., 40 CFR 64 for compliance assurance monitoring; 40 CFR 70.6(a)(3) for periodic monitoring; 40 CFR 70.6(c)(1) for sufficiency monitoring). In addition, emissions limits must be enforceable as a practical matter (contain appropriate averaging times, compliance verification procedures, and recordkeeping requirements). In light of the above, the permit must:

- Be sufficient to show compliance or noncompliance (i.e., through monitoring times of operation, fuel input, or other indices of operating conditions and practices); and

- Specify a reasonable averaging time consistent with established reference methods, contain reference methods for determining compliance, and provide for adequate reporting and recordkeeping so that air quality agency personnel can determine the compliance status of the source.

4.2.7 Emissions Trading Program Overview

States have the option of implementing an emissions trading program or other alternative measure instead of requiring BART. This option provides the opportunity for achieving better environmental results at a lower cost than a source-by-source BART requirement. A trading program must include participation by BART sources, but may also include sources that are not subject to BART. The program would allow for implementation during the first implementation period of the Regional Haze rule (that is, by the year 2018) instead of the 5-year compliance period. The basic steps that the state would need to complete for an emissions trading program are:

1. Develop emission budgets;
2. Allocate emission allowances to individual sources; and
3. Develop a system for tracking individual source emissions and allowances.

MPCA has not formally decided whether to utilize an implementation plan with unit-specific BART limitations or an emissions trading program. However, the fact that the State is investing time and resources in a project to assess BART requirements for the taconite industry indicates that an implementation plan is the probable option that will be taken to meet Regional Haze requirements.

4.3 *Summary of Recent Court Rulings*

The information provided in this section is based on the May 24, 2002 District of Columbia (D.C.) Court of Appeals decision (no. 99-1348), American Corn Growers Association vs. EPA; the September 19, 2002 decision, American Corn Growers Association vs. EPA; and the September 8, 2003, Federal Register notice regarding a proposed Consent Decree between EPA and Environmental Defense. A copy of the May 24, 2002, Court of Appeals decision is located in Attachment G.

4.3.1 May 2002 D.C. Circuit Court of Appeals Decision

4.3.1.1 Background

American Corn Growers Association and other industry petitioners, including groups representing coal companies, railroads, and coal-fired electric generators, filed an appeal over several issues in the Regional Haze rule. The petitioners claimed that:

Claim #1. EPA acted contrary to the law in establishing a group rather than a source-by-source approach to BART determinations;
Claim #2. EPA acted without legal authority and in an arbitrary and capricious manner by promulgating the "natural visibility goal" and "no degradation requirement;" and
Claim #3. EPA failed to set reasonable criteria for measuring or assuring "reasonable progress," and acted contrary to law in extending the statutory deadline for submission of the state Regional Haze control plans.

The Sierra Club also requested a review of the "reasonable progress" criteria of the rule, arguing that the rule is an effective and cost-efficient method of controlling Regional Haze.

On May 24, 2002, the D.C. Circuit Court of Appeals issued an opinion in the appeal of the Regional Haze Rule. The court determined that the portion of the rule addressing BART (Claim #1) contravened the CAA by not giving states enough discretion in applying it. However, the court upheld the EPA's Regional Haze goals (Claim #2) and reasonable progress criteria (Claim #3). The court declined to rule on the "reasonable progress" issues brought by the Sierra Club, finding that they were premature.

4.3.1.2 BART Issues

Each state must determine BART for each source that emits a pollutant which may reasonably be anticipated to cause or contribute to Class I visibility impairment. Section 4.2.4 discusses the five statutory criteria that states must consider when deciding what BART controls to place on a source. They are:

1. The costs of compliance,
2. The energy and non-air quality environmental impacts of compliance,
3. The 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.

The petitioners noted that while the rule requires states to address the first four criteria on a source-by-source basis, it requires the fifth criteria to be addressed on a group basis. A BART-eligible source is "'reasonably anticipated to cause or contribute' to Regional Haze if it can be shown that the source emits pollutants within a geographic area from which pollutants can be emitted and transported downwind to a Class I area." In addition, the rule requires states to "assess the degree of visibility improvement that would be achieved in each Class I area on the basis of emission reductions achievable from all sources subject to BART located within the region that contributes to visibility impairment in the Class I area in the region of the Class I area." The petitioners argued that using a group-basis rather than a source-by-source BART approach contravenes the language, statutory structure, and legislative history of Section 169a of the CAA and unlawfully constrains the states by requiring BART controls at sources without any empirical evidence of the particular source's contribution to visibility impairment in a Class I area.

EPA argued that its bifurcated approach to determining appropriate BART controls should be upheld because Section 169a is unclear about how a state must analyze anticipated visibility improvement. However, the court ruled agreed with the petitioners that treating one of the five factors differently was contrary to the language and structure of the CAA. All five factors were meant to be considered together to help the states determine what BART controls are appropriate. The court stated that this is most apparent with respect to the states' duty to take into account "the costs of compliance" in deciding not only whether to order an individual source to install any new pollution control equipment, but also what type of equipment: the only way for states to determine whether the costs are appropriate is to compare the costs to the individual source with the degree of visibility improvement from installing controls at that source. The court found that under EPA's approach, it is entirely possible that a source may be forced to spend millions of dollars for new technology that will have no appreciable effect on the haze in any Class I area.

The court also upheld that the BART provisions are inconsistent with the CAA's provisions giving the states broad authority over BART determinations. The rule unlawfully constrains the states' statutory authority because under the CAA it is the states - not EPA - who must determine which BART-eligible sources should be subject to BART. The rule requires BART controls based simply on a finding that a source could affect a Class I area, thus giving the states no authority to determine the appropriate controls for each source. The court cited the Conference Report on the 1977 amendments to the CAA, which states that the states, not EPA, shall determine what constitutes BART. The court also noted that if the rule contained some kind of a mechanism by which a state could exempt a BART-eligible source on the basis of an individualized contribution determination, then perhaps the meaning of the CAA would not be violated.

Thus, the court held that the BART provisions of the Regional Haze rule are impermissible.

4.3.1.3 "Natural Visibility" Goal and "No Degradation" Requirement

The industry petitioners cited four arguments in support of their claim that the "natural visibility" goal and the "no degradation" requirement in the Regional Haze rule should be vacated as "arbitrary and capricious":

1. EPA exceeded its authority under Section 169a and adopted regulations that conflict with the Prevention of Significant Deterioration (PSD) program in establishing "natural visibility" as the goal of the Regional Haze program;
2. The regulations impermissibly constrain state discretion in requiring that the states develop their visibility programs using the "no degradation" requirement as a benchmark;
3. EPA has no authority to impose upon the states the goal of achieving "natural visibility" conditions, and thereby restrict the opportunity of some states to participate in the planning process aimed at addressing Regional Haze; and
4. EPA promulgated the rule without providing adequate notice and an opportunity for comment.

EPA claimed that petitioners' challenge to the natural visibility goal and their claims of inadequate notice were not properly raised. The court found no merit in EPA's contentions. However, the court also found no merit in industry petitioners' claims and therefore denied their challenge to the "natural visibility" goal and the "no degradation" requirement as neither manifestly contrary to the statute nor arbitrary or capricious in substance.

Petitioners claimed that the natural visibility goal and the no degradation requirement are contrary to the PSD program, because that program recognizes that some impairment of visibility would be acceptable in Class I areas. The court rejected this argument because the CAA creates a national goal of remedying visibility impairment and the Regional Haze rule complements that goal. Furthermore, the court believes the PSD program does not create an entitlement to degrade visibility.

Petitioners also argued that because states must determine the "reasonable progress" sources should make in enhancing visibility, and that reasonable progress could sometimes require visibility degradation, the no degradation requirement restricts states' authority to apply the statutory criteria. The court found this claim incorrect because the no degradation requirement simply elucidates "reasonable progress," which does not include the possibility of visibility degradation.

Petitioners also asserted that the Regional Haze rule somehow restricts the opportunity of some states to participate in the planning process aimed at addressing Regional Haze, the court found no real evidence in support of this claim.

Finally, petitioners claimed that they did not have fair notice and adequate opportunity to comment on the regulatory goal of natural visibility. The court found this argument to be without merit. The court found that industry had received adequate notice because there was no material inconsistency between the statutory goal of 169a and the regulatory goal of "natural visibility."

4.3.1.4 "Reasonable Progress" Criteria and the Extension of the Statutory Deadline

The Sierra Club argued that the Regional Haze rule's requirements for improvement in visibility during the 20 percent most impaired days and for no degradation during the 20 percent least impaired days do not qualify as "reasonable progress" criteria and are arbitrary and capricious. The court held that the issue is unripe for review because the BART issue was remanded, and because EPA could change its criteria for evaluating reasonable progress on remand.

The Sierra Club also argued that the provision in the rule allowing states 3 years to file Regional Haze SIPs for areas designated "attainment" or "unclassifiable" violated the CAA. The Transportation Equity Act for the 21st Century (TEA–21) provisions establish and link deadlines for the Regional Haze SIPs and $PM_{2.5}$ monitoring and area designations. TEA-21 provides that for areas designated as "attainment" or "unclassifiable", EPA must require SIPs to be submitted 1 year after the area has been designated. Although the court expressed doubts about the validity of the three-year deadline, it remanded the issue with the group-BART provisions.

4.3.2 September 2002 D.C. Circuit Court of Appeals Decision

Based on the decision reached on May 24, 2002 by the D.C. Circuit Court of Appeals that the portion of the Regional Haze rule addressing BART contravened the CAA by not giving states enough discretion in applying it, EPA petitioned the court for a rehearing. The court denied the petition on September 19, 2002, and the May decision will stand unless appealed successfully to the U.S. Supreme Court.

4.3.3 August 2003 Proposed Consent Decree for BART Deadline

In a September 8, 2003, Federal Register notice,[13] EPA is requesting written comments by October 8, 2003, regarding a proposed Consent Decree. On August 15, 2003, Environmental Defense filed a complaint alleging that EPA had failed to meet its mandatory duty to promulgate BART regulations. On August 19, 2003, EPA lodged the proposed Consent Decree with the United States District Court for the District of Columbia Circuit.

The proposed Consent Decree provides that EPA will sign a notice of proposed rulemaking setting forth its proposed BART regulations and guidelines no later than April 15, 2004, with submittal to the Office of Federal Register no later than five days following signature. The Decree also establishes an April 15, 2005, deadline for signing a final notice of rulemaking, with submittal to the Office of Federal Register no later than five days following signature. See Table 3-2 for the relationship between these proposed regulatory deadlines and the anticipated timeline for compliance with BART.

[13] 68 FR 52922

5 Taconite Industry Overview and BART-Eligible Source Identification

MPCA has identified the taconite industry as an industry requiring an analysis to identify the impacts of the federal Regional Haze rule. Barr has completed a BART screening evaluation in Sections 6 and 7 identifying and summarizing the feasibility of control options for the taconite industry. This evaluation will serve as a tool and template consistent with EPA's proposed BART guidance. As a first step before performing the BART screening evaluation, Sections 5.1 through 5.7 provide an overview of the taconite industry and Sections 5.8 and 5.9 identifies and categorizes BART-eligible units at Minnesota taconite plants.

Some of the information provided in Sections 5.1 through 5.5 is based on MPCA's December 30, 1999 "Taconite Iron Ore Industry in the United States" report.

5.1 *Iron Ore Ranges*

Iron ore is mined and processed in the U.S. mainly on the Mesabi Range of northern Minnesota and the Marquette Range of the Upper Peninsula of Michigan. The Mesabi Range is located approximately 65 miles north of Duluth, MN. The range is approximately 120 miles long from Grand Rapids to Babbitt with a thickness of 400 to 750 feet. The iron-ore material that is mined, concentrated, and pelletized is magnetite (Fe_3O_4), or magnetic taconite. The Marquette Range is located in the northern part of the Upper Peninsula of Michigan with its eastern end 10 miles west of the Lake Superior port of Marquette. The range is approximately 30 miles long and 6 miles wide. The iron-ore material that is mined, concentrated, and pelletized is magnetite and hematite (Fe_2O_3).

5.2 *Taconite Mining and Processing Facilities*

This report focuses on the six active taconite mining and processing facilities located on the Mesabi Range of Minnesota. The facilities are: EVTAC Mining, LLC, (Mine and Plant), Hibbing Taconite Company, Ispat-Inland Steel Mining Company, Keewatin Taconite, Northshore Mining Company (Mine and Plant), and U.S. Steel Minnesota Ore Operations.

Operations at the taconite facilities vary based on several factors, including when the facility was built and what technology was available, the type of crude ore the facility mines, and the type of pellet product the facility is making. These and other factors can affect the mining, crushing, concentrating, and pelletizing processes, which are described in more detail below.

5.3 *Taconite Pellets*

Taconite is a low-grade iron ore used to make taconite pellets. The iron in the taconite ore is composed of magnetic ore (magnetite) and non-magnetic ore (hematite and limonite). These forms of iron must be oxidized to be suitable for steel production. The taconite ore is crushed, and the iron is removed to produce a concentrate. Ore concentrate, a binding agent and other additives are mixed to form "green balls". Green balls are ⅜ to ½ inches in diameter and have an iron content of approximately 65 % by weight. The green balls are oxidized and heat hardened at about 2,400 °F to produce taconite pellets. The finished product is shipped to steel mills for steel production.

5.4 *Mining*

The taconite ore is extracted in an open pit mine. First, the earth and rock on top of the ore (overburden) is removed. Drilling and blasting is necessary to remove the rock overburden. Soils and rock debris are removed with earthmovers, trucks and other heavy equipment and placed in storage areas. Next, the iron ore is removed. Drilling, blasting and materials handling equipment is necessary to remove the iron ore and transport it to the crusher where the crude ore is reduced to pieces sized at 10 inches or less. After crushing, the iron ore is transported to the pellet plant via conveyor, truck or rail for further processing. Emissions from mining are generally coarse fugitive dust produced in the mine pits, at ground level or slightly elevated sources. These emissions generally do not travel significant distances; so, they are not likely to have a significant impact on visibility. Most of the fugitive dust emissions are from the haul roads. Water suppression and chemical stabilization methods are generally used to control particulate emissions.

All taconite plants have fugitive particulate emission management plans in place. These plans are prepared by each plant to control particulate emissions per MN rule 7011.0150. The control plans are reviewed by MPCA as part of the Title V permit re-issuance process, which occurs every five years. The plans must include control measures that are deemed reasonable for preventing particulate matter from becoming airborne per Minn. R. 7011.150, and are updated as needed within the permit review process. Since process for a dust control plan review is already in place, little can be gained in terms of further emission reductions via a BART evaluation. Therefore, no further analysis will be conducted on mining emissions in this study.

5.5 *Pellet Plant Overview*

In the pellet plant, the raw iron ore is crushed, concentrated, pelletized, and baked (via induration) to produce taconite pellets.

5.5.1 Crushing

Taconite ore must be finely crushed so that the iron ore can be extracted. Multi-stage crushing and grinding systems are used. Crushing systems often consist of a coarse crushing stage, which reduces the crude ore to 10 inch or smaller pieces, as well as a fine crushing stage, which further reduces the coarsely crushed ore to about 1 inch pieces. Most dry crushers are currently vented to particulate control equipment.

5.5.2 Ore Grinding and Iron Separation

Using water, the ore is further ground and milled to optimum particle size in rod and ball mills. Where water is used in the grinding process, no particulates are emitted. Magnetic separators separate the iron-bearing particles (concentrate) from the non-iron bearing particles (tailings). Other equipment used to form concentrate includes cyclones, hydro separators, screens, and flotation. Iron ore separation is a wet process and no particulates are emitted.

5.5.3 Pelletizing

The wet concentrate is mixed with a binder and other additives to form “soft” or “green” balls in balling machines. Since these processes are wet, they are not sources of particulate emissions. Binders and additives are stored as dry materials. Some particulate emissions are associated with material handling of the binders and additives.

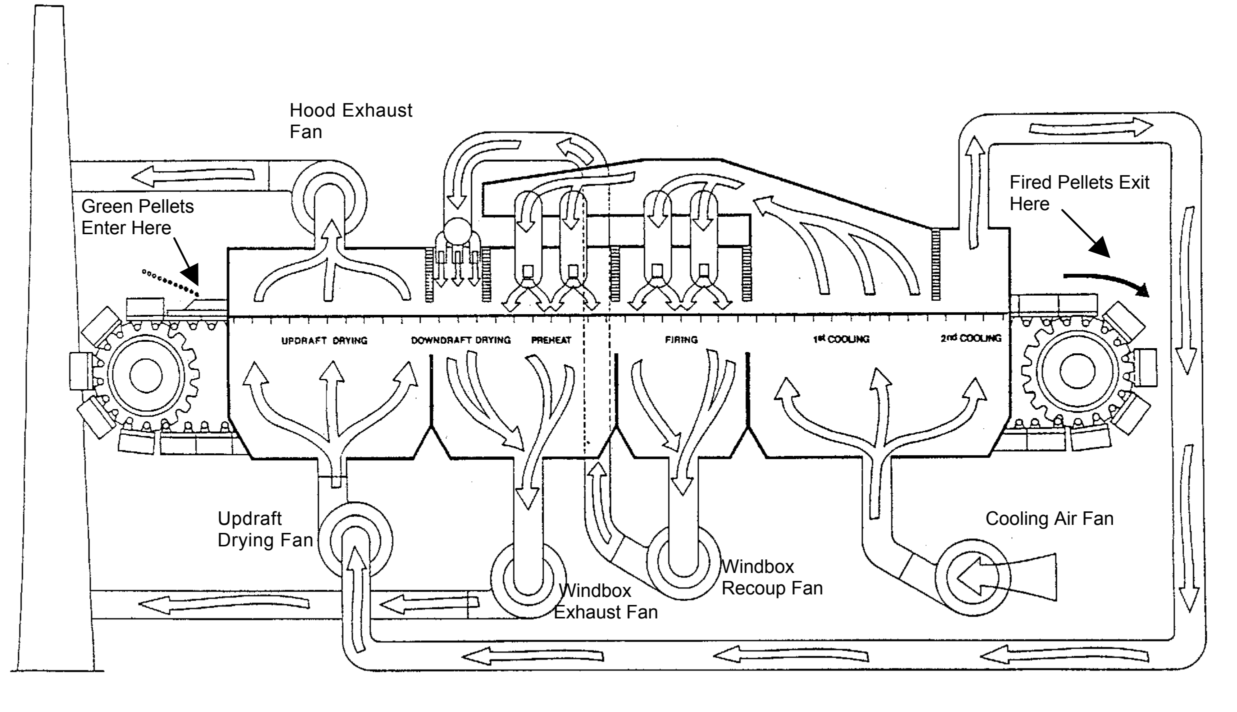
5.5.4 Induration

The pellets are oxidized and heat-hardened in the induration furnace. Discharged pellets are cooled, screened, and transferred on conveyor belts to bins or stockpiles for storage. The stored pellets are loaded to ships or trains for shipment to the steel mill.

Historically, three types of induration furnaces have been used in the taconite industry: straight grate, grate/kiln and vertical shaft furnaces. Only straight grate and grate/kiln induration furnaces are in operation at this time. One facility has inactive vertical shaft furnaces, and that facility does not anticipate operating the vertical shaft furnaces in the future. This study focuses on the two active types of induration furnaces.

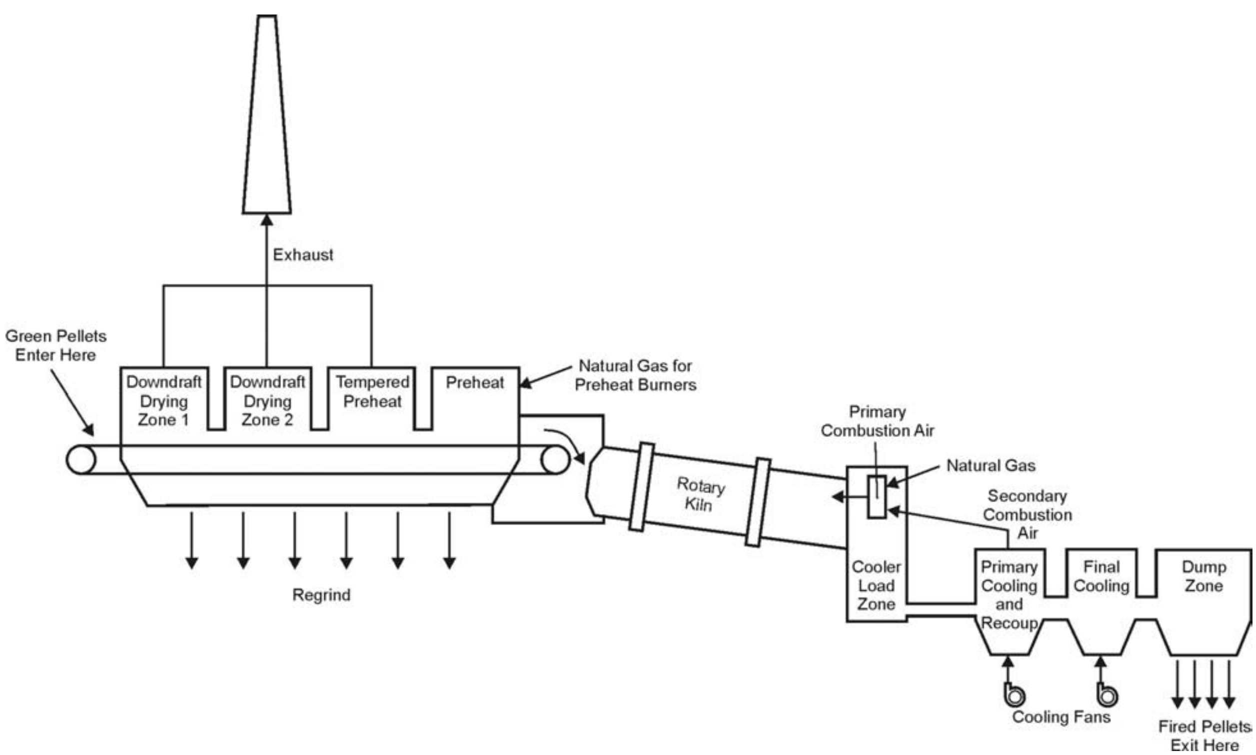
Figure 5-1 on the following page is a general diagram of a straight grate induration furnace. Figure 5-2 is a general diagram of a grate/kiln induration furnace.

Figure 5-1. General Diagram of a Straight Grate Induration Furnace



Courtesy: Hibbing Taconite Company

Figure 5-2. General Diagram of a Grate/Kiln Induration Furnace.



The induration process involves pellet pre-heating, drying, hardening, oxidation and cooling. In a straight grate furnace, pellets move through the entire furnace on a traveling grate. In a grate/kiln furnace, pellets are dried on a grate and then transferred to a rotary kiln for hardening and oxidation. The pellet hardening and oxidation section of the induration furnace is designed to operate at 2,400 ºF. This temperature is required to meet taconite pellet product specifications. Fuel combustion in the induration furnace is carried out at 300 % to 400 % excess air to provide sufficient oxygen for pellet oxidation.

Natural gas, fuel oil, sawdust, petroleum coke, and coal are fuel sources used in induration furnaces at the Minnesota taconite plants. The fuel is primarily combusted in the pellet hardening and oxidation section of the furnace. Fuel is also used in the pre-heat/drying section at some of the furnaces. Air is used for combustion, pellet cooling, and as a source of oxygen for pellet oxidation. Due to the high-energy demands of the induration process, induration furnaces have been designed to recover as much heat as possible. Pellet preheat zones are heated with the hot gases generated in the pellet hardening/oxidation section and the pellet cooler sections. Each of these sections is designed to maximize heat recovery with process constraints. Hot air from the pellet coolers is also used for fuel combustion, allowing for more of the fuel's energy to be directed to the process instead of heating ambient air to combustion temperatures.

Visibility-impairing pollutants emitted from the pelletizing operation include particulate matter, sulfur dioxide, nitrogen oxides, and volatile organic compounds.

Nitrogen oxides (NOx) are formed by both the thermal oxidation of nitrogen in the combustion air and the reduction and subsequent oxidation of fuel bound nitrogen. The majority of NOx emissions from a pellet plant are from thermal oxidation due to the high oxygen levels and high operating temperatures present in the induration furnaces. NOx emissions are released to the atmosphere in the induration furnace flue gas.

Sulfur dioxide (SO_2) emissions originate from both fuel combustion (depending on the sulfur content in the fuel used) and the oxidation of sulfur present in the green balls. SO_2 emissions are released to the atmosphere in the induration furnace flue gas.

Particulate matter emissions emanate from both fuel combustion, especially if a solid fuel is used, and the attrition of particles (dust) in the taconite pellets. Particulate emissions from the pellets are caused by the abrasion of pellets rubbing against each other and against the equipment as the pellets move through the induration furnace. Particulates are released to the atmosphere in the induration furnace flue gas and in the pellet cooler exhaust.

Volatile organic compound emissions are formed by the incomplete combustion of fuels in the induration furnace. These emissions are negligible due to both the high oxygen levels and high operating temperatures present in the induration furnace.

5.5.5 Material Handling

Conveyors and mobile equipment (e.g. front end loaders) are used to transport the taconite ore, ore concentrate, pellets, pellet binding/blending materials, and solid fuels in the taconite plants.

Particulate emissions are caused by wind blowing across conveyors, conveyor drops, and drops from mobile equipment. Many of these sources are either enclosed and/or connected to control devices to minimize particulate emissions. Fugitive emissions may also occur at storage piles of ore, ore concentrate and finished pellets.

5.6 *Boilers, Heaters, and Diesel Engines*

The taconite industry uses boilers and heaters to generate steam for pressurized steam power, process and space heating, and electricity generation. Diesel engines are used primarily for back-up electricity generation. This equipment is not specific to the taconite industry; many industrial sectors use boilers, heaters, and diesel engines. As decided upon in the working group coordination meeting on March 18, 2003, this equipment will be reviewed as a separate BART source classification and are not included in this evaluation.

5.7 *Taconite Industry Emissions Data*

As discussed in Section 4.2.2, the visibility-impairing pollutants per the BART proposed guidelines[14] are SO_2, NOx, PM_{10}, VOC, and NH_3.

For comparison purposes, total actual emissions of visibility-impairing pollutants from the six Minnesota taconite facilities and two Michigan facilities are provided below in Table 5-1. [15] In addition, the total limited potential to emit at Minnesota taconite facilities for each visibility-impairing pollutant is shown in this table.[16] Potential to emit data at Michigan taconite facilities are not readily available from the Michigan Department of Environmental Quality (MDEQ).[17]

[14] 66 FR 38107.
[15] The 2001 actual emissions data at Minnesota taconite facilities are taken from MPCA's website (http://www.pca.state.mn.us/air/emissions/emissearch.cfm). The 2001 actual emissions data at Michigan taconite facilities are taken from MDEQ's website (http://www.deq.state.mi.us/maers/emissions_query.asp).
[16] The potential to emit data at Minnesota taconite facilities are provided by MPCA from their Delta database.
[17] May 2, 2003 e-mail correspondence from Mr. Thomas Maki of Michigan Department of Environmental Quality to Mr. Joel Trinkle of Barr.

Table 5-1
Emissions of Visibility-Impairing Pollutants from the Eight U.S. Taconite Facilities by State

Visibility-Impairing Pollutant	Minnesota 2001 Actual Emissions (tons)	Michigan 2001 Actual Emissions (tons)	Minnesota Limited Potential to Emit[2] (tons)
SO_2	8,129	2,514	24,638
NOx	27,636	9,829	76,707
PM_{10}	10,648	562	29,135
VOC	177	103	2,118
Ammonia	NA[1]	NA[1]	NA[1]

[1] Ammonia is not reported in the Minnesota emission inventories and has only recently been added as a required reportable pollutant in Michigan for certain source classification codes. The EPA's National Emissions Inventory (NEI) Version 2 reports ammonia emissions of 0.260 tons per year for a three-month period from one taconite plant in Minnesota.

[2] Potential to emit data for the Northshore Mining Company's Babbitt Mine are unavailable and have not been included. The only visibility-impairing pollutant emitted in a significant quantity under the BART guidelines (100 tpy) from this facility is PM_{10}. Actual 2001 PM_{10} emissions from this facility are 176 tons.

Table 5-1 indicates that VOC and ammonia are not emitted in significant quantities from the taconite plants. The BART screening study for the taconite industry focuses on SO_2, NOx, and PM_{10} as the pollutants of concern.

5.8 *BART-Eligible Sources*

5.8.1 Initial MPCA BART Survey Request

MPCA surveyed the Minnesota taconite facilities to establish a list of potential BART sources, based on pollutants emitted and dates in existence and in operation (see handout included in Attachment C). MPCA provided Barr with a summary of the returned BART surveys.[18]

5.8.2 Categorization of BART-Eligible Units at the Minnesota Taconite Plants

An appropriate first step in evaluating BART for a group of sources is to categorize emission units within the "taconite ore processing facilities" source category. Grouping several emission units into a few categories will allow efficient evaluation of available control technology options for the industry. The regulatory study is based on three emission unit source types: 1) particulate fugitive sources, 2) particulate point sources, and 3) induration point sources. Particulate fugitive sources include unpaved roads, transfer conveyors, and stockpiles. Particulate point sources include ore conveyors, crushers, additive handling, pellet coolers, screens, and product conveyors. Induration point sources include straight grate furnaces and grate-kiln systems. Each

[18] Barr was not asked to verify the accuracy or completeness of the BART surveys.

of the three emission categories includes multiple sources as shown in Table 5-2 below. Refer to handout included in Attachment C for categorization of BART-eligible sources.

Table 5-2
Emission Unit Categories at Taconite Ore Processing Facilities

Taconite Emission Unit Category	Example Sources
Particulate Fugitive Source	Unpaved Roads Conveyors (transfer point not enclosed) Mobile Equipment Stockpiles
Particulate Point Source	Crushers Screens Conveyors (transfer point enclosed) Bins Blenders Grates Coolers Pellet Discharge
Induration Point Source (Particulate and Combustion Emissions)	Straight Grate Grate-Kiln

The emission sources at taconite ore processing facilities are categorized into the three emission unit categories to facilitate both the selection of model sources in Section 5.8.3 for the BART screening evaluation and for the review of applicable air regulations in Section 9.

5.8.3 Taconite Industry Model Sources

In order to facilitate the BART screening evaluation of emission units at the taconite plants, Barr proposed to the working group at the March 18, 2003, working group coordination meeting that taconite emission units can be classified into five source categorizations:

- Group 1: fugitive particulate-only sources,
- Group 2: point particulate-only sources,
- Group 3: induration point sources (induration furnace stacks),
- Group 4: external combustion sources, and
- Group 5: internal combustion sources.

The focus of the BART screening evaluation is on the group 2 and group 3 sources. Group 1 fugitive particulate-only sources are already required to meet dust control requirements under Minnesota rules, and they are not expected to contribute significantly to visibility impairment at Class I areas several miles away due to the relatively poor far-field atmospheric dispersion from low-lying stockpiles. As described in Section 5.6, groups 4 and 5 should be reviewed as a separate BART source classification and are not included in this evaluation.

From source category groups 2 and 3, Barr chose four “model sources” to enable the development of representative control cost estimates. The four model sources are as follows:

- Straight gate induration furnace,
- Grate/kiln induration furnace,
- Pellet cooler, and
- Iron ore material handling.

The physical characteristics of these model sources are summarized in Table 7-1. The model sources are selected to reflect emission units found at taconite facilities and that are specific to the taconite industry. As described in Section 5.5.4, straight grate and grate/kiln induration furnaces are chosen because they are the predominant types of furnaces at these plants. Pellet coolers are chosen because they are a common source of particulate matter. Iron ore material handling is chosen because it occurs in several phases of taconite plant operations and it represents many material handling emission points. The taconite industry source categories and model sources are summarized in Table 5-3.

Table 5-3
BART Eligible Source Classification for Taconite Industry Sources

Primary Source Type	Secondary Source Type	Industrial Source Type	BART Model Source
1.00 Particulate Fugitive Source	1.01 Unpaved Roads	Mine	
	1.02 Material Handling (Conveyor)	Mine	
	1.03 Material Handling (Mobile Equipment)	Mine	
	1.04 Material Handling (Other)	Mine	
	1.03 Wind Erosion (Stockpile)	Mine, Taconite	
	1.04 Wind Erosion (Other)	Mine, Taconite	
2.00 Particulate Point Source	2.01 Crushing	Taconite	
	2.02 Material Handling – Ore	Taconite	X
	2.03 Material Handling – Additive	Taconite	
	2.04 Material Handling – Coal	Taconite	
	2.05 Straight Grate (Grate)	Taconite	
	2.06 Straight Grate (Pellet Discharge)	Taconite	
	2.07 Grate-Kiln (Grate)	Taconite	
	2.08 Grate-Kiln (Cooler)	Taconite	X
	2.09 Grate-Kiln (Pellet Discharge)	Taconite	
	2.10 Material Handling – Pellets	Taconite	
	2.11 Paint Gun	Taconite	
3.00 Induration Point Source	3.01 Straight Grate (Induration)	Taconite	X
	3.02 Grate-Kiln (Induration)	Taconite	X
4.00 External Combustion Source	4.01 Boiler (Electrical Generator)	Ext. Combustion	
	4.02 Boiler	Ext. Combustion	
	4.03 Heater (Make-up)	Ext. Combustion	
	4.04 Zinc Melt Furnace	Ext. Combustion	
5.00 Internal Combustion Source	5.01 Diesel Engine	Int. Combustion	

The selection of model sources is based in part on the level of emissions at each source category. Emission inventory data from year 2001 at the Minnesota taconite plants are sorted by taconite source category for groups 2 and 3. Each source category summary is examined for the number of sources and emission rates associated with that category.

Iron ore material handling is selected as the model source for PM emissions from Group 2. The other source categories in Group 2 are similar to ore handling. The primary difference between secondary source categories in Group 2 is the type of materials processed. The final BART evaluation that each facility will perform for Group 2 material handling emission units should be similar to the screening evaluation of the model iron ore material handling source.

Pellet coolers are distinct source type within Group 2 because air is blown across the pellets for convective cooling. This does not take place in the other Group 2 material handling sources; therefore, pellet coolers are analyzed by a separate model source.

Straight grate furnaces and grate/kiln furnaces were selected as model sources for PM, NOx and SO_2 emissions in Group 3.

Source category emissions data from the 2001 emissions inventory are summarized in Table 5-4. Note that the percent of the group total emissions to the facility-wide emissions takes into account emissions from all taconite plant and mine sources listed in the emission inventory.

Table 5-4
2001 PM10 Emissions (tpy) Breakdown for Group 2 and 3 Source Categories

Group 2 Secondary Source Category Description	**No. of Sources in EI**	**2001 PM10 Emissions (tpy)**				**Percent of Group to Facility-wide PM10 Emissions**
		Avg	**Max**	**Min**	**Total**	
2.01 Crushing	78	3.4	6.9	0.0	267.2	2.5%
2.02 Material Handling – Ore	110	9.3	59.1	0.1	1,027.0	9.6%
2.03 Material Handling – Additive	40	2.0	28.7	0.0	80.1	0.8%
2.04 Material Handling – Coal	16	0.1	2.0	0.0	2.0	0.0%
2.05 Straight Grate (Grate)	0	NA	NA	NA	NA	
2.06 Straight Grate (Pellet Discharge)	4	16.2	20.6	5.3	64.7	0.6%
2.07 Grate-Kiln (Grate)	12	74.3	125.6	7.3	892.0	8.4%
2.08 Grate-Kiln (Cooler)	4	48.7	129.5	2.9	194.7	1.8%
2.09 Grate-Kiln (Pellet Discharge)	0	NA	NA	NA	NA	
2.10 Material Handling - Pellets	57	13.0	269.1	0.2	738.4	6.9%
Group 2 Total PM10 Emissions					**3,266**	**30.7%**
Group 3 Secondary Source Category Description						
3.01 Straight Grate (Induration)	2	152	157	147	304	2.9%
3.02 Grate-Kiln (Induration)	9	434	1,299	81	3,906	36.7%
Group 3 Total PM10 Emissions					**4,210**	**39.6%**
Group 2 and 3 Total PM10 Emissions					**7,476**	**70.3%**

Table 5-5
2001 SO_2 and NOx Emissions (tpy) Breakdown by Type of Induration Furnace

Pollutant	Straight Grate	Grate-Kiln	Induration Furnace Total	Facility-wide Emissions	Percent of Induration Furnace to Facility-wide Emissions
NOx	3,737	18,186	21,923	27,636	79.3%
SO_2	281	5,689	5,970	8,129	73.4%

Table 5-5 shows that the PM10, SO_2, and NOx emissions from group 2 and 3 sources constitute over 70 percent of total actual 2001 facility-wide emissions.

6 Identification of Available Control Technologies

This section describes each potentially available control technology evaluated for the taconite industry model sources defined in Section 5.8.3. The technologies are grouped by the pollutant that they control (i.e., NOx, SO_2, or PM).

Determining technical feasibility of a control technology for a new source (e.g., determining best available control technology at a new induration furnace) will be different than determining technical feasibility for a retrofit at an existing source (e.g., determining best available retrofit technology at an existing induration furnace). In this section, Barr determines the technical feasibility of each control technology for a taconite plant emission unit as if that unit could be designed or re-designed to meet the control device physical and operating parameters. In Section 7, Barr performs an additional technical feasibility evaluation of each remaining control technology as a retrofit to an existing emission unit, consistent with BART.

For mining operations, control technology options for PM_{10} include dust suppression and enclosure. For crushing and concentrating operations, control technology options for PM_{10} include enclosure, dust suppression system, scrubber (low/high efficiency), fabric filter, and electrostatic precipitator. For pelletizing operations, control technology options for PM_{10} include multiclone, baghouse, scrubber, and electrostatic precipitator/wet electrostatic precipitator; control technology options for SO_2 include scrubber (low/high efficiency) and wet electrostatic precipitator; control technology options for NOx include combustion control, low- NOx burner, selective catalytic reduction, and selective non-catalytic reduction. For this report, two types of low-NOx burners are evaluated, staged fuel low-NOx burners and induced flue gas recirculation burners (IFGR or ultra-low NOx). External flue gas recirculation is a common technique for controlling NOx emissions, so it is added to the list of NOx control technologies for review.

As part of the BART screening evaluation, a literature review was conducted to identify potential new control equipment options that were not included in the list of control equipment from the draft report submitted on May 12, 2003. The results of the literature search are summarized in spreadsheet format in Attachment H.

6.1 *NOx Emission Control Options*

Nine different control technologies are evaluated for NOx emissions from induration furnace waste gases. Of these, three have been determined technically infeasible for induration furnaces: (1) coal addition to green taconite pellets, (2) non-selective catalytic reduction, and (3) low-temperature oxidation.

Section 6.1.10 considers site-specific operational factors that may reduce NOx emissions without employing control technologies.

6.1.1 External Flue Gas Recirculation

External flue gas recirculation (EFGR) uses flue gas as an inert material to reduce flame temperatures. In an external flue gas recirculation system, flue gas is collected from the heater or stack and returned to the burner via a duct and blower. The flue gas is mixed with the combustion air and this mixture is introduced into the burner. The addition of flue gas reduces the oxygen content of the "combustion air" (air + flue gas) in the burner. The lower oxygen level in the combustion zone reduces flame temperatures; which in turn reduces NOx emissions. The normal NOx control efficiency range for EFGR is 30% to 50%.

6.1.2 Low-NOx Burners

Low-NOx burner (LNB) technology utilizes advanced burner design to reduce NOx formation through the restriction of oxygen, flame temperature, and/or residence time. LNB is a staged combustion process that is designed to split fuel combustion into two zones, primary combustion and secondary combustion. This analysis utilizes the staged fuel design in the cost analysis because lower emission rates can be achieved with staged fuel burner than with a staged air burner.

In the primary combustion zone of a staged fuel burner, NOx formation is limited by a rich (high fuel) condition. Oxygen levels and flame temperatures are low; this results in less NOx formation. In the secondary combustion zone, incomplete combustion products formed in the primary zone act as reducing agents. In a reducing atmosphere, nitrogen compounds are preferentially converted to molecular nitrogen (N_2) over nitric oxide (NO).

The estimated NOx control efficiency for Low NOx burners in high temperature applications is 25%.

6.1.3 Induced Flue Gas Recirculation Burners

Induced flue gas recirculation burners, also called ultra low-NOx burners, combine the benefits of flue gas recirculation and low-NOx burner control technologies. The burner is designed to draw flue gas to dilute the fuel in order to reduce the flame temperature. These burners also utilize staged fuel combustion to further reduce flame temperature.

The estimated NOx control efficiency for IFGR burners in high temperature applications is 50%.

6.1.4 Selective Non-Catalytic Reduction

In the selective non-catalytic reduction (SNCR) process, urea or ammonia-based chemicals are injected into the flue gas stream to convert NO to N2 and water. Without the participation of a catalyst, the reaction requires a high temperature range to obtain activation energy. The relevant reactions are as follows:

$$NO + NH_3 + 1/4\ O_2 \rightarrow N_2 + 3/2\ H_2O$$
$$NH_3 + 1/4\ O_2 \rightarrow NO + 3/2\ H_2O$$

The optimum operating temperature for SNCR is 1,600°F to 2,000°F. Under these conditions reaction (1) dominates, and a significant reduction in NOx occurs. At temperatures above 2,000°F reaction (2) begins to dominate and NOx control efficiency decreases rapidly.

The normal NOx control efficiency range for SNCR is 50% to 70%.

6.1.5 Selective Catalytic Reduction

Selective catalytic reduction (SCR) is a post-combustion NOx control technology in which ammonia (NH_3) is injected into the flue gas stream in the presence of a catalyst. NOx is removed through the following chemical reaction:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

A catalyst bed containing metals in the platinum family is used to lower the activation energy required for NOx decomposition. SCR requires a temperature range of 500°F – 800°F for a normal catalyst. The optimum operating temperature range is 700°F to 750°F.

A high temperature zeolite catalyst is also available; it can operate in the 600 °F – 1000°F temperature range. However, these catalysts are very expensive.

The normal NOx control efficiency range for SCR is 70% to 90%.

6.1.6 Ported Kilns

Ported kilns are rotary kilns that have air ports installed at specified points along the length of the kiln. The purpose of the ports is to allow air injection into the pellet bed as it travels down the kiln bed. Ports are installed about the circumference of the kiln. Each port is equipped with a closure device that opens when it is at the bottom position to inject air in the pellet bed, and closed when it rotates out of position.

The purpose of air injection is to provide additional oxygen for pellet oxidation. The oxidation reaction extracts enough heat to offset the heat loss associated with air injection. Air injection reduces the overall energy use of the kiln and produces a higher quality taconite pellet. Air injection also prevents carry over of the oxidation reaction into the pellet coolers.

Minntac has worked with Metso Minerals to install two ported kilns. Metso's product specifications for ported kilns suggest a 5% reduction in energy use. Minntac has confirmed that they have achieved at least a 5% reduction in fuel consumption. They also have seen a slight reduction in NOx emissions over and above the reduction in energy use. This is most likely the result of lower temperatures in the kiln from air injection.

6.1.7 Coal Addition to Pellets with Low Excess Air in the Induration Furnace

John Engesser of the Minnesota Department of Natural Resources (MDNR) has been performing research on the impact of coal addition to green taconite pellets as a possible way to reduce NOx emissions from pellet induration. Coal addition of 0.6% was shown not to adversely affect pellet quality. Pellet quality began to degrade when coal addition was increased to 1%.

The MDNR did not find a significant reduction in NOx emissions from the coal addition under normal induration conditions in their test furnaces at 300% excess air. The MDNR's data suggests an average reduction in NOx emission of 10 % when the excess air levels in the test furnaces was reduced to 25 % to 75%. The test furnaces operate on a batch basis, and much of the energy consumption is due to heating the furnace up to test conditions. The MDNR postulates that a 75% reduction can be achieved if this practice is carried out in a continuously operated kiln.

The project is still in the research phase and more research is needed. It is not commercially available at this time. Coal addition to green taconite pellets is not considered further in the BART screening evaluation.

6.1.8 Non-Selective Catalytic Reduction

A non-selective catalytic reduction (NSCR) system is a post combustion add-on exhaust gas treatment system. It is often referred to as "three-way conversion" catalyst since it reduces NOx, unburdened hydrocarbons (UBH), and CO simultaneously. NOx and CO react in the presence of NSCR catalyst to form nitrogen (N_2) and carbon dioxide (CO_2). In order to operate properly, the combustion process must be near-stoichiometric conditions. SCONOx™ is a commercially available example of an NSCR system. SCONOx™ employs a single catalyst that simultaneously oxidizes CO to CO_2 and NO to NO_2. NO_2 formed by the oxidation of NO is subsequently absorbed onto the catalyst surface through the use of a potassium carbonate absorber coating. CO_2 produced by these reactions is released to the atmosphere. The potassium carbonate catalyst coating reacts with NO_2 to form potassium nitrites and nitrates. Prior to saturation of the potassium carbonate coating, the catalyst must be regenerated.

SCONOx™ is typically employed in clean gas services such as natural gas fired turbines. The SCONOx™ catalyst is very sensitive to contaminants in the waste gas and would not be viable in induration waste gas service. NOx control efficiency for NSCR is approximately 90% in clean combustion applications.

When Barr evaluated SCONOx™ for a potential new taconite plant in 2001, Goal Line Technologies indicated that SCONOx™ is technologically infeasible in this application.

NSCR is not considered further in the BART screening evaluation.

6.1.9 Low Temperature Oxidation

Low temperature oxidation (LTO) utilizes ozone as a medium to oxidize various pollutants including NOx. In the system, NOx in the flue gas is oxidized by means of ozone to form nitrogen trioxide or nitrogen pentoxide. These compounds react with water vapor to form nitric acid. The nitric acid vapor is then absorbed as dilute nitric acid and is neutralized by the sodium hydroxide in the scrubbing solution to form sodium nitrate. The sodium nitrate is separated and discharged to the wastewater system. LTO is typically employed at locations where the nitrate byproduct and be used or recycled.

BOC Gases' Lo-TOx is an example of a commercially available version of an LTO system that was evaluated by Barr in 2001 for a potential new taconite plant. Lo-TOx technology uses ozone to oxidize NO to NO_2 and NO_2 to N_2O_5 in reactor. The N_2O_5 is converted to HNO_3 in a scrubber, and is removed with caustic. The reactions are as follows:

$O_3 + NO \rightarrow O_2 + NO_2$
$NO2 + O3 \rightarrow 2\ N_2O_5$
$N_2O_5 + H_2O \rightarrow 2\ HNO_3$
$NaOH + HNO_3 \rightarrow NaNO_3 + H2O$

The normal NOx control efficiency range for Lo-TOx is 80% to 95%.

Lo-TOx would require a minimum of two process columns, a reactor for NOx oxidation, and a scrubber for nitrate removal. In addition, an ozone generator with a supply of liquefied oxygen would be required. As a result of equipment requirements, this is a rather expensive control technology. Nitrates are produced as a byproduct of this control technology. At a taconite plant, there is no place to utilize these nitrates, so this wastewater would be routed to the tailings basin. Nitrates in the tailings basin would pose a threat to ground and surface water. Tables I-15 and I-16 in Attachment I contain cost estimates for application of Lo-TOx technology for the model source grate/kiln induration furnace. The estimated control cost is $6,310/ton for the 175 ppm NOx case and $12,500/ton for the 50 ppm NOx case. Based on the NOx emission rate[19], the control cost for a straight grate induration would be similar to the 50 ppm NOx grate/kiln estimate. The estimates are based on bid data from the 2001 Taconite BACT study.

Barr contacted Tri-Mer Corporation, the manufacturer of the Tri-NOx® LTO system, to determine the applicability of LTO at a potential new taconite plant in 2001. The vendor stated that Tri-NOx® LTO system is not commercially available for use on a taconite pellet induration furnace. Tri-Mer stated that the magnitude of the air streams from an induration furnace is too large for the chemistry used in the Tri-NOx® system to reduce NOx effectively.

LTO is not considered further in the BART screening evaluation.

6.1.10 Site-specific Measures

Site-specific measures may also be employed to reduce NOx emissions. Under this option, taconite plant operators would employ the best operating practices identified for NOx reduction using existing equipment.

One option is to evaluate NOx emission rates under various operating conditions to identity which conditions lead to the lowest NOx emission rates. NOx emission rates could be determined by stack testing, continuous emission monitors, or predictive emission monitors.

[19] Equipment costs in the Lo-TOx vendor quotes were directly proportional to the NO_x removal rate; waste gas flow rates did not have a significant impact on equipment costs..

If a taconite plant is capable of using more than one fuel type, another option is to evaluate the impact of fuels on NOx emission rates. Stack test data from one facility shows a 60% reduction in NOx emissions when using coal instead of natural gas. A 30% reduction occurred when firing 16% wood waste, and a 50% reduction when firing 28% wood waste. If this option is employed, increases in SO_2 and PM emissions should be compared to the NOx reductions to identify the best net reduction in visibility impairing pollutants.

6.2 *SO_2 Emission Control Options*

Four control technologies are evaluated for SO_2 emissions from induration furnace waste gases. Of these, two have been determined technically infeasible for induration furnaces: 1) dry scrubbing lime/limestone injection, and 2) spray dryer absorption.

6.2.1 Wet Walled Electrostatic Precipitator

A wet walled electrostatic precipitator (WWESP) operates on the same collection principles as a dry ESP (see Section 6.3.5), and uses a water spray to remove particulate matter from the collection plates. For SO_2 removal, caustic is added to the water spray system, allowing the WWESP spray system to function as an SO_2 absorber.

The SO_2 control efficiency for a WWESP is approximately 80%.

6.2.2 Wet Scrubbing / Flue-Gas Desulfurization

Wet scrubbing techniques are used to control both particulate and SO_2 emissions. As discussed in Section 6.3.8, particulate scrubbers are wet scrubbers that remove particles from waste gas by capturing the particles in liquid droplets (usually water) and separating the droplets from the gas stream. Wet scrubbing processes used to control SO_2 are generally termed flue-gas desulfurization (FGD) processes. FGD utilizes gas absorption technology, the selective transfer of materials from a gas to a contacting liquid, to remove SO_2 in the waste gas. Caustic, crushed limestone, or lime are used as scrubbing agents. The BART screening evaluation assumes that caustic (sodium hydroxide solution) is the scrubbing agent. The SO_2 removal reactions are as follows:

$$Na^+ + OH- + SO_2 + \rightarrow Na_2SO_3$$
$$2Na^+ + 2OH- + SO_2 + \rightarrow Na_2SO_3 + H_2O$$

Limestone scrubbing introduces limestone slurry with the flue gas in a spray tower. The sulfur dioxide is absorbed, neutralized, and partially oxidized to calcium sulfite and calcium sulfate. The overall reactions are shown in the following equations:

$$CaCO_3 + SO_2 \rightarrow CaSO_3 \cdot 1/2\ H_2O + CO_2$$
$$CaSO_3 \cdot 1/2\ H_2O + 3H_2O + O_2 \rightarrow 2\ CaSO_4 \cdot 2\ H_2O$$

Lime scrubbing is similar to limestone scrubbing in equipment and process flow, except that lime is a more reactive reagent than limestone. The reactions for lime scrubbing are as follows:

$$Ca(OH)_2 + SO_2 \rightarrow CaSO_3 \cdot 1/2\ H_2O \quad + 1/2\ H_2O$$
$$Ca(OH)_2 + SO_2 + 1/2\ O_2 + H_2O \rightarrow CaSO_4 \cdot 2\ H_2O$$

Caustic scrubbing produces a liquid waste, and minimal equipment is needed. If lime or limestone is used as the reagent for SO_2 removal, additional equipment will be needed for preparing the lime/limestone slurry and collecting and concentrating the resultant sludge. Calcium sulfite sludge is watery; it is typically stabilized with fly ash for land filling. The calcium sulfate sludge is stable and easy to dewater. To produce calcium sulfate, an air injection blower is needed to supply the oxygen for the second reaction to occur.

The normal SO_2 control efficiency range for SO_2 scrubbers is 80% to 90% for low efficiency scrubbers and 90% to 95% for high efficiency scrubbers

6.2.3 Dry Scrubbing Lime/Limestone Injection

Lime/limestone injection is a post-combustion SO_2 control technology in which pulverized lime or limestone is directly injected into the duct upstream of the fabric filter. Dry sorption of SO_2 onto the lime or limestone particle occurs and the solid particles are collected with a fabric filter. Further SO_2 removal occurs as the flue gas flows through the filter cake on the bags. The normal SO_2 control efficiency range for dry SO_2 scrubbers is 70% to 90%.

Induration waste gas streams are high in water content and are exhausted at or near their dew points. Gases leaving the induration furnace are typically in the 100 °F to 150 °F range as compared to a utility boiler exhaust that operates at 350 °F or higher. Under induration furnace waste gas conditions, the baghouse filter cake could become saturated with moisture and plug both the filters and the dust removal system. In facilities where wet scrubbers are used, water in the scrubber exhaust would compound this problem. Therefore, this control system is not considered technically feasible in induration waste gas service and is not considered further in the BART screening evaluation.

6.2.4 Spray Dryer Absorption

Spray dryer absorption (SDA) systems spray lime slurry into an absorption tower where SO_2 is absorbed by the slurry, forming CaSO3/CaSO4. The liquid-to-gas ratio is such that the water evaporates before the droplets reach the bottom of the tower. The dry solids are carried out with the gas and collected with a fabric filter. When used to specifically control SO_2, the term flue-gas desulfurization (FGD) may also be used.

As with the dry scrubbing system in Section 6.2.3, under induration furnace waste gas conditions, the baghouse filter cake could become saturated with moisture and plug both the filters and the dust removal system. In addition, the lime slurry would not dry properly and it would plug up the dust collection system. Therefore, spray dryer absorption is not technically feasible in this application and is not considered further in the BART screening evaluation.

6.3 *PM Emission Control Options*

Eight control technologies are evaluated for PM emissions in induration waste gas, induration pellet cooler exhaust, enclosed material handling sources, or fugitive sources. All of these control technologies are deemed technically feasible for a new unit.

6.3.1 Best Management Practices

Best management practices are preventative measures that minimize the release of particulate matter into the environment. Best management practices may include the proper design and maintenance of equipment, good housekeeping, and good operating practices such as using telescopic chutes for loading and unloading procedures, limiting drop heights, covering truck beds, and orienting storage piles perpendicularly to prevailing winds to reduce the exposed surface.

The PM control efficiency range for best management practices varies depending upon the application.

6.3.2 Wet Suppression

Wet suppression is a potential control method for particulate matter emitted from material handling and other fugitive sources. Wet suppression systems apply either water or water containing a chemical surfactant or foaming agent to the surface of the particulate generating material. The chemical surfactant or foaming agent agglomerates and binds the particulates to the aggregate surface thus eliminating or reducing its emission potential.

The normal PM control efficiency range for wet suppression is 50% to 75%.

6.3.3 Enclosure

An enclosure is a potential control method for particulate emissions from material handling sources. Enclosures, either partial or complete, surround the source as much as possible without interfering with the process operations. Enclosures prevent particulate matter from becoming airborne as a result of disturbance created by ambient winds or by mechanical entrainment resulting from the operation of the source causing the emissions.

The normal PM control efficiency range for an enclosure is 50% to 100%.

6.3.4 Cyclone Separator

Cyclone separators, or multiclones, are a potential control method for particulate emissions in induration waste gas, induration pellet cooler exhaust, or enclosed material handling sources. Cyclone separators are designed to remove particles by causing the exhaust gas stream to flow in a spiral pattern inside of a tube. Owing to centrifugal forces, the larger particles slide down the wall and drop to the bottom of the cyclone where they are removed. The cleaned gas flows out of the top the cyclone.

There are two principal types of cyclones: tangential entry and axial entry. In tangential entry cyclones, the exhaust gas enters an opening located on the tangent at the top of the unit. In axial flow cyclones, the exhaust gases enter at the middle of one end of a cylinder and flows through vanes that cause the gas to spin. A peripheral stream removes collected particles, while the cleaned gas exits at the center of the opposite end of the cylinder.

A typical emission control rate for a multiclone is 50% to 80%. The control efficiency for cyclone separators is less for small particles than larger particles. Particle size distribution data is necessary to properly determine the control efficiency for a specific application.

6.3.5 Electrostatic Precipitator

An electrostatic precipitator (ESP) is a potential control method for particulates in induration waste gas, induration pellet cooler exhaust, or material handling sources that are enclosed. An electrostatic precipitator applies electrical forces to separate suspended particles from the flue gas stream. The suspended particles are given an electrical charge by passing through a high-voltage DC corona region in which gaseous ions flow. The charged particles are attracted to and collected on oppositely charged collector plates. Particles on the collector plates are released by rapping and fall into hoppers for collection and removal.

The normal PM control efficiency range for an ESP is 98% to 99+%.

6.3.6 Wet Walled Electrostatic Precipitator

A wet walled electrostatic precipitator (WWESP) is a potential control method for particulates in induration waste gas, induration pellet cooler exhaust, or material handling sources that are enclosed. A WWESP operates on the same collection principles as a dry ESP, and uses a water spray to remove particulate matter from the collection plates.

The normal PM control efficiency range for a WWESP is 98% to 99+%.

6.3.7 Fabric Filter

A fabric filter, or baghouse, is a potential control method for particulates in induration pellet cooler exhaust, or material handling sources that are enclosed. Moisture levels in the induration waste gas are too high for fabric filters. A fabric filter, or baghouse, consists of a number of fabric bags placed in parallel inside of an enclosure. Particulate matter is collected on the surface of the bags as the gas stream passes through them. The particulate is periodically removed from the bags and collected in hoppers located beneath the bags. A number of methods are employed to facilitate the removal of particulate from the bags, including shaking, reverse air flow, and pulse air flow.

The normal PM control efficiency range for a fabric filter is 98% to 99+%.

6.3.8 Particulate Scrubbers

A scrubber is a potential control method for particulates in induration waste gas, induration pellet cooler exhaust, or material handling sources that are enclosed. Particulate scrubbers, also termed wet scrubbers, remove particles from waste gas by capturing the particles in liquid droplets (usually water) and separating the droplets from the gas stream. The droplets transport the particulate out of the gas stream.

Scrubbers capture the particulates through the following mechanisms:

1. Impaction of the particle directly into a target droplet
2. Interception of the particle by a target droplet as the particle comes near the droplet
3. Diffusion of the particle through the gas surrounding the target droplet until the particle is close enough to be captured

Scrubbers are generally classified according to the liquid contacting mechanism used. The most common scrubber designs are spray-chamber scrubbers, cyclone spray chambers, orifice and wet-impingement scrubbers, and venturi and venturi jet scrubbers.

The normal PM control efficiency range for a scrubber is 90% to 95% for a low efficiency scrubber and 95% to 99+% for a high efficiency scrubber.

7 Application of BART Screening to Model Taconite Sources

The first four of the five BART evaluation steps described in Section 4.2.4 are completed in this section on an industry-wide screening level. The fifth step, selecting BART, will ultimately be performed on a case-by-case evaluation by the facility and MPCA.

The analysis of potential BART control technologies must take into account:

- The available retrofit control options,
- Any pollution control equipment in use at the source,
- The costs of compliance with control options,
- The remaining useful life of the facility, and
- The energy and non-air quality environmental impacts of control options.

The BART screening study uses model sources, which are similar to some actual emission sources at taconite plants to evaluate potential control costs for step 4. Each taconite plant is different, and site-specific issues must be considered in the BART analysis. An actual BART analysis must be conducted for individual taconite facilities so that facility-specific factors are taken into account. Please see Section 7.1.2 for a list of issues for consideration in the site-specific analysis. The screening BART analysis used the following primary information sources. A literature search for this study is contained in Attachment H of this report. Cost information was developed from the following sources:

- Emission control costs are estimated using the capital and operating cost estimate factors in the EPA Air Pollution Control Cost Manual , sixth edition (EPA/452/B-02-001).
- Control equipment costs are estimated from vendor quotations from a 2001 BACT study by Barr for a potential new taconite plant. These estimates are adjusted for inflation using the Vatavuk Air Pollution Control Cost Indexes.
- Information gaps are addressed by collecting additional cost data from control equipment manufacturers.
- Gas and electric costs are based on the U.S. Department of Energy's 2002 data for industrial sources (http://www.eia.doe.gov).
- Wastewater treatment costs are obtained from the EPA Air Pollution Control Cost Manual. The EPA-estimated treatment costs are used as a placeholder for site-specific values. Please see Section 7.1.2 with regard to site-specific factors that could significantly affect wastewater treatment costs.

The BART screening evaluation in this report does not make recommendations for the selection of BART in step 5. Final selection of BART will be done on a facility-by-facility basis. This will allow consideration of site-specific issues in control equipment construction costs, pollution control efficiency and compliance costs.

7.1 *General Control Technology Review Issues*

This section outlines important issues that must be taken into account when performing a case-by-case BART evaluation.

7.1.1 Emission Controls vs. Impact on Visibility

In accordance with 40 CFR 51.308(e)(1)(ii)(A) and (B), a BART determination must be based on the following two analyses:

> "*(A) An analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source …; and*
>
> *(B) An analysis of the degree of visibility improvement that would be achieved in each mandatory Class I Federal area as a result of the emission reductions achievable from all sources subject to BART located within the region that contributes to visibility impairment in the Class I area, based on the analysis conducted under paragraph (e)(1)(ii)(A) of this section."*

The emission control costs reported in this section for the model sources are in units of dollars per ton of pollutant removed. However, each pollutant has a different impact on visibility. At a July 8, 2003 meeting on Regional Haze, Mr. Gordon Andersson at MPCA indicated that sulfates comprise the majority of mass of haze generating emissions. Nitrates are also a major contributor during winter months. A study on visibility impairment by Colorado State University found that sulfates contribute 54 % of the visibility impairment and nitrates contribute 17 % of the visibility impairment in the Voyageurs National Park and BWCAW.

7.1.2 Site-specific Factors that Affect Control Costs

Although the model sources have been developed to provide a general indication of the technical and economic feasibility of each control technology, a unit-specific BART evaluation must still be performed. A case-by-case evaluation should consider these steps.

- Determine the technical feasibility of listed control equipment for each source subject to BART. Check the technical feasibility analysis to see if analysis is consistent with site-specific conditions. Eliminate all technologies that are infeasible.

- Conduct a control cost analysis on the remaining technologies per the listed control technology rankings. It is recommended that site-specific vendor quotes be obtained to get accurate cost analysis results. If there are a significant number of similar sources, select a typical-sized source to minimize the amount of work needed to perform the cost analysis. Use the appropriate model source cost analysis in the attachments to this report as guidance for the cost analysis. Review the list of factors that affect site-specific retrofit costs. Identify those factors for which costs will affect control equipment installation at the site and include them in the cost analysis. Check the utility costs listed in the attachments to this report, and make the appropriate adjustments in the cost calculations.

- Compare the calculated control costs to the results of the economic affordability analysis to determine which controls are economically feasible and select the appropriate controls as BART. Conduct a site-specific economic analysis of control cost affordability.

Site-specific factors can significantly impact the installed costs of pollution control equipment. This is especially true at retrofits of existing equipment, which is the case with BART-eligible sources. Site-specific factors that can impact control costs include:

- Site preparation work due to removal of existing equipment or modification of existing buildings and structures.

- Site access for equipment delivery and erection. Existing buildings and structures may limit access to the construction site by cranes and other construction equipment.

- Additional engineering costs to address piping and duct work tie-ins to existing equipment and structural issues caused by installing new equipment that was not planned for in the original equipment design. Process Safety Management Hazardous Operation (Haz-Op) review requirements and resultant safety system designs could also add to engineering costs.

- Additional piping and insulation costs to fit new piping and ductwork within existing pipe racks and equipment support structures.

- Auxiliary equipment that may be needed to accommodate the new control system e.g. blowers, heat exchangers, duct burners, or bypass stacks.

- Lost production due to process equipment down time while the new equipment is being installed. This generally occurs when piping and duct work are tied in to existing equipment.

- Taconite plants are located in relatively remote locations; freight costs will be higher than standard estimating factors.

- Taconite plants are large facilities. Installation of control equipment will likely require on-site fabrication, which increases construction costs.

- Site-specific wastewater treatment costs should be carefully evaluated. Different iron ore and raw materials used in pellet production affect the type of constituents in induration emissions (e.g. chlorides, fluorides, sulfates and various metals). When these materials are captured by wet scrubbing systems, they will likely affect wastewater quality, and the impact of scrubber blowdown on wastewater/tailings management systems should be considered. Compliance with water quality standards also needs to be considered.

Taconite plants are located in different watersheds, which have differing water quality issues. Site-specific water quality issues could significantly affect water treatment costs. Currently, no taconite plant has water treatment facilities for scrubber blowdown. A case-by-case study of wastewater treatment requirements and costs is needed for the economic analysis of pollution control costs.

7.2 *Model Source Parameters*

The BART screening evaluation uses model sources to develop cost estimates for pollution control equipment. The model source parameters are listed in Table 7-1.

The model source parameters were set at the mid-point of the range of equipment in Minnesota's taconite plants. These parameters are determined using 2001 emission inventory data, taconite performance test data from MPCA's report, "U.S Taconite Iron Ore Industry" by Hongming Jiang, and Barr's taconite plant performance testing experience.

Table 7-1
Taconite Model Source Characteristics for BART Screening Evaluation

Source Type	Vent Type	Stack Exhaust Parameters							
		Normal Flow (dscfm)	Normal Flow (acfm)	Design Flow [1] (acfm)	Temperature (F)	Moisture (%)	SO_2 Conc. (ppm)	NOx Conc. (ppm)	PM10 (gr/dscf)
Straight Grate	Induration Waste Gas	150,000	188,865	207,751	135	12%	5	80	0.008
Grate/Kiln	Induration Waste Gas	300,000	377,730	415,503	135	12%	20 (low) and 130 (high) [2]	50 (low) and 175 (high) [2]	0.050
Pellet Cooler	Pellet Cooler Exhaust	100,000	239,425	263,368	800	2%	NA	NA	0.007
Ore Material Handling	Conveyor Drop Conveyor Drop Height Conveyor Width Throughput	7000 10 ft 5 ft 5.00E+06 tpy ore	7,143	7,857	77	2%	NA	NA	0.05 [3]

[1] Design flow is estimated at 10% greater than normal flow. Design flow is used to estimate equipment costs; normal flow is used to estimate operating costs.
[2] A “low” and a “high” case for SO_2 and NOx stack concentration are used in the screening evaluation to account for different types of existing controls at the taconite plants.
[3] PM concentration of 0.05 gr/dscf is based on emissions using AP-42 factors and a flow rate of 7000 dscfm. It is a more realistic estimate than the allowable grain loading standard of 0.3 gr/dscf in Minnesota rules.

7.3 *Model Induration Furnace NOx Control Technology Review*

Thermal NOx from fuel combustion is the primary source of emissions from induration. Fuel-based NOx emissions are also present where fuel oil and solid fuels are used. However, test data from one taconite facility showed a reduction in NOx when firing solid fuels.

As shown in Section 8, no specific regulatory limits for NOx emissions exist for taconite induration furnaces.

7.3.1 BART Step 1: Identify All Available Retrofit Control Technologies

Control technologies available for NOx are as follows:

- External Flue Gas Recirculation (EFGR)
- Low-NOx Burners (Staged Fuel)
- Internal FGR (Ultra Low NOx Burners)
- Selective Non Catalytic Reduction (SNCR)
- Selective Catalytic Reduction (SCR)
- Ported Kilns

See Section 6.1 for additional information on these control technologies and additional technologies identified in the literature search.

7.3.2 BART Step 2: Eliminate Technically Infeasible Options

A summary of the technical feasibility analysis is listed in Table 7-2. Details of the analysis for each control technology follow the summary table.

Table 7-2
Summary of Technical Feasibility for Induration NOx Emissions

Control Technology	Feasibility Determination	Issues That Affect Control Technology Feasibility
1. EFGR	Infeasible	Induration requires high oxygen levels in the furnace to oxidize pellets. EFGR would reduce oxygen levels below required levels.
2. Low-NOx Burners	Feasible only at pre-heat section	Feasible only at the induration furnace pellet pre-heat section. Infeasible at the induration furnace due to excessive temperature and oxygen level.
3. IFGR Burners	Feasible only at pre-heat section	Feasible only at the induration furnace pellet pre-heat section. Infeasible at the induration section of the furnace due to excessive temperature and oxygen level.
4. SNCR	Infeasible	No points to inject reagent at the proper temperature and/or potential ammonium sulfate plugging problems in the preheat section of the induration furnace.
5. SCR	Feasible only if exhaust gas is re-heated	Installation directly in the induration process is likely infeasible, since there is not a location within the system at a proper operating temperature. Installation as add on control device is feasible if exhaust gases are re-heated to the SCR operating temperature.
6. Ported Kiln	Feasible only at grate/kiln systems	Two ported grate/kilns are currently in operation.

1. EFGR - Infeasible

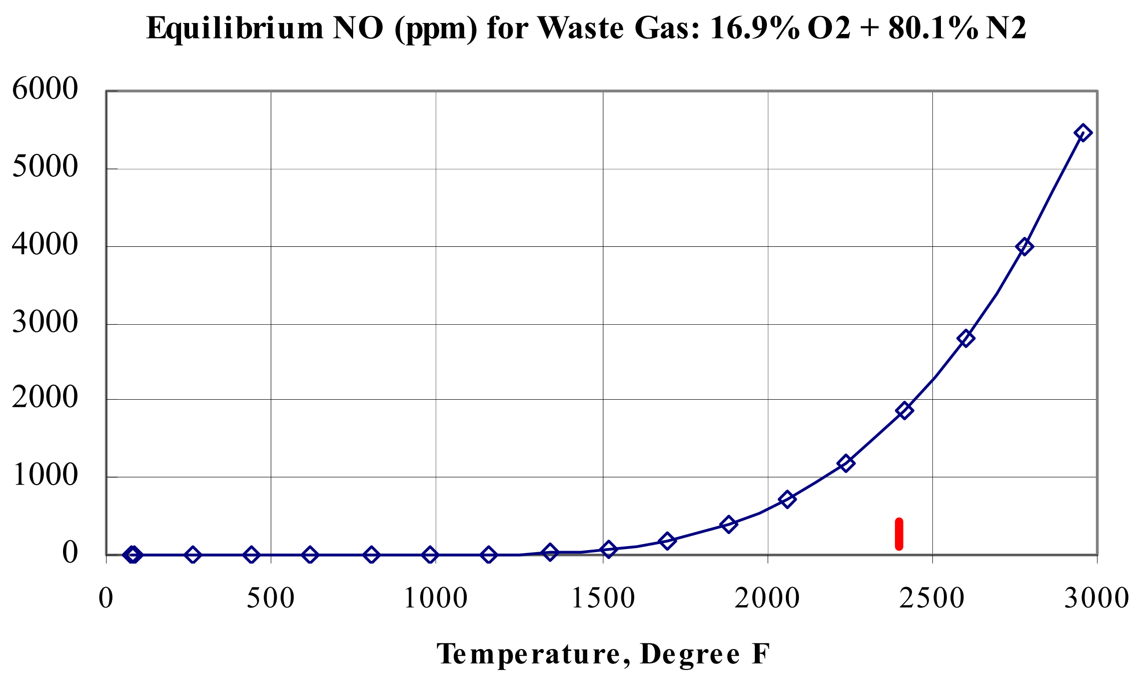
It is not a viable option to re-route flue gas to the combustion zone of the induration process. External flue gas recirculation would lower the temperature range and oxygen levels needed for pellet induration. Pellets must be held at an optimum temperature (2400 to 2450 °F), in the presence of excess oxygen, for a sufficient time to allow oxidation to reach the pellet center and allow realignment of the molecules to form stronger microstructures in the pellet.

2 and 3. Low-NOx and IFGR Burners – Feasible only in pre-heat section

Operating conditions in the induration furnace are inconsistent with the NOx control mechanisms used in these burners. Low-NOx and IFGR burners reduce NOx formation by restricting flame temperature under low oxygen levels. In the induration furnace, pellets must be heated to, and maintained at, a temperature of 2400 to 2450°F, to produce a completely oxidized, high strength and abrasion resistant pellet. High flame temperatures are needed for the radiant heat transfer needed to maintain these temperatures. In addition, high levels of oxygen are needed to achieve proper oxidation. Typical operating conditions are at 15% to 17% oxygen. Induration furnaces are designed to use pre-heated combustion air to conserve energy. Air preheat restricts that ability of low NOx and IFGR burners to reduce NOx formation.

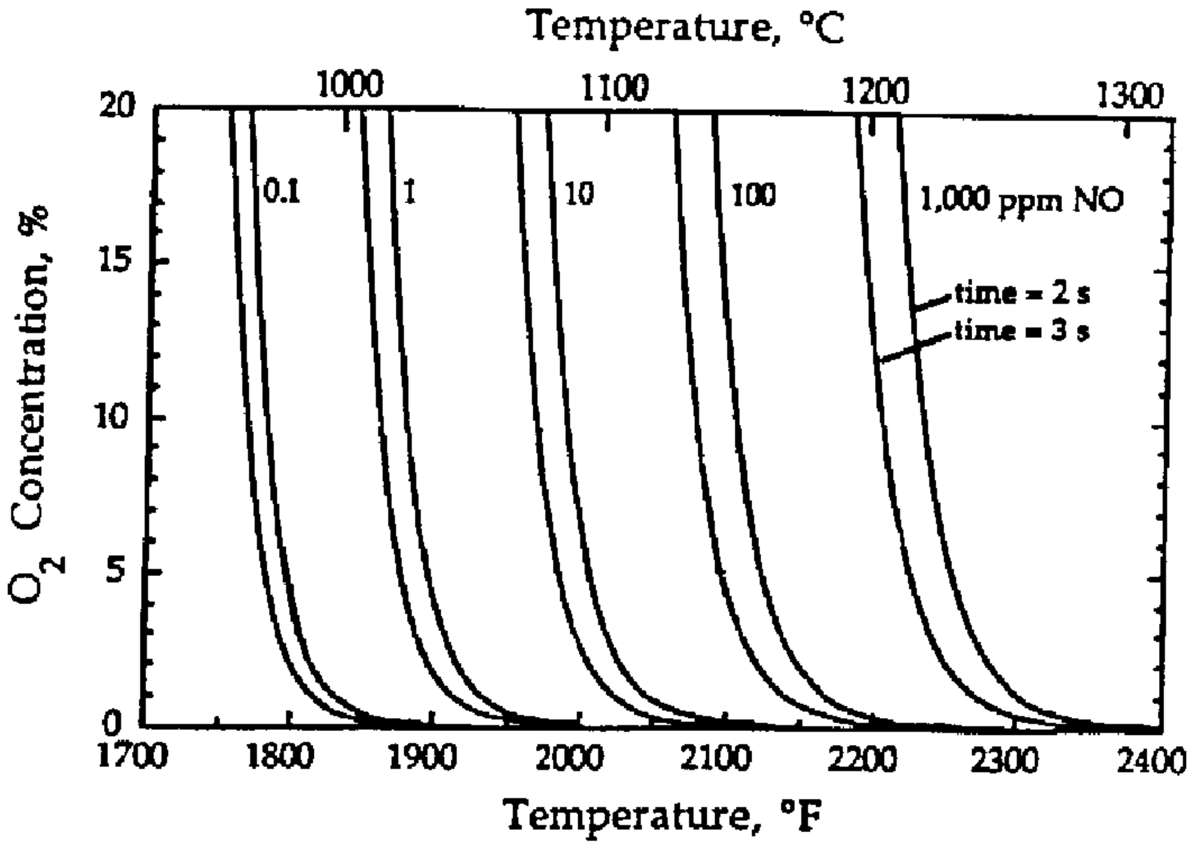
Figure 7-1 shows the equilibrium concentrations of NO at different temperatures. The tick mark for induration furnaces on this curve shows that there is a high potential for NOx formation. . Figure 7-2 on the following page shows NOx formation rates at several temperature ranges. Each set of curves shows the concentrations of NO formed in 2 to 3 seconds at the listed temperature and oxygen concentrations. Induration furnace conditions are similar to the 1,000 ppm NOx curve. This curve shows how conducive the induration furnace operating conditions are to NOx formation. Under these conditions low-NOx and IFGR burners would be ineffective.

Figure 7-1. Equilibrium NOx Concentrations at Various Temperatures for a Typical Induration Furnace Waste Gas



Source: Minnesota Pollution Control Agency; Hongming Jiang

Figure 7-2. Impact of Temperature on NOx Formation



Source: "Alternative Control Techniques Document—NOx Emissions from Process Heaters (Revised)," US EPA, EPA-453/R-93-034, September 1993.

Temperatures in the pellet pre-heat section are typically below 2,000 °F. At this temperature range, the use of low-NOx and IFGR burners is technically feasible. However, the NOx control efficiency of burners installed at these conditions is limited due to the high temperature of the combustion air and the high levels of oxygen present for pellet oxidation. Site-specific product quality concerns may limit the feasibility of this option. For example, one facility cannot make fully fluxed pellets if there is a reduction in temperature in the pre-heat zone. This could preclude use of low NOx burners due to the lower flame temperatures in low NOx burners.

Low NOx and IFGR Burners typically have longer flame patterns than standard burners. The impact of longer flames should be evaluated when considering installation of these burners.

No test data are available to substantiate the feasibility of Low NOx burners. Low NOx burners have only been installed at one straight grate facility, but no performance tests were conducted before or after installation of the low NOx burners; so, it cannot be determined if these burners actually reduce NOx emissions. Low NOx burners have not been installed at a grate/kiln facility.

4. SNCR – Infeasible

The SNCR reagents must be injected into the furnace at 1,600 °F to 2000 °F. The operating temperatures in induration furnaces exceed this temperature window. An induration furnace is designed such that the flue gas dries and pre-heats the taconite pellets. As the induration flue gas heats the taconite pellets, its temperature drops below the SNCR operating temperature range. Therefore, it may be difficult to locate an appropriate temperature window for SNCR in an existing induration flue gas duct system.

A second issue with SNCR is the potential for plugging in the induration furnace pre-heat section due to the presence of ammonium sulfate salts. Sulfur oxides present in the induration waste gas can react with excess ammonia from the SNCR process to form ammonium salts. These materials are very sticky and cause plugging problems if the gas drops below the dew point of 350° F. Temperatures below 350° F will occur in the preheat section; therefore; it is likely that the ammonium salts will deposit on the cool surfaces present in the preheat zone.

Ammonia also poses potential water quality issues. Ammonia slip released to the atmosphere could contaminate surface waters by deposition. If an induration waste gas scrubber is used, excess ammonia could contaminate the tailings basin as water is recycled from the tailings basin to the plant.

5. SCR – Feasible only if within SCR temperature range

The SCR catalysts generally work only in an operating temperature range of 500 °F to 800 °F. The operating temperatures in induration furnaces exceed this temperature window. An induration furnace is designed such that the flue gas dries and pre-heats the taconite pellets. This is accomplished using blowers and ductwork to move the hot gases from the induration furnace to the pellet pre heat section. As the induration flue gas heats the taconite pellets, its temperature drops. In order for SCR to work, there must be a point in the ductwork that is within the SCR operating temperature range. Therefore, it is unlikely that an appropriate temperature window for SCR exists within the induration furnace system. Alternatively, the exhaust gas must be re-heated in order for this technology to be considered technically feasible.

If SCR is used in combination with a PM control device on the induration waste gas stream, it may be possible to install the SCR upstream of particulate controls. SCR systems for coal power plants have been designed to operate upstream of particulate controls. In this case, structured SCR catalyst blocks are used, and soot blowing can be used to prevent catalyst bed plugging.

As noted above, ammonium sulfate salt plugging is a potential issue if sufficient sulfur oxides and ammonia are present in the preheat section of the induration furnace. This issue should be carefully reviewed in the site-specific analysis.

6. Ported kilns – Feasible only for grate/kiln systems

Two ported grate/kiln systems are currently in operation. This technology has not been researched and is not commercially available for straight grate furnaces.

7.3.3 BART Step 3: Rank Remaining Control Technologies

The remaining control technologies and their control efficiencies are presented in Table 7-3.

Table 7-3
Control Technology Rankings for Induration NOx Control

Control Technology	Control Efficiency
1. SCR	70% to 90%
2. IFGR Burners	50%
3. Low-NOx Burners	25%
4. Ported Kiln	$\geq$ 5%

7.3.4 BART Step 4: Evaluate Impacts and Document the Results

A discussion of relevant impacts, including (A) economic, (B) environmental, and (C) energy, for each of the four technically feasible control technologies is detailed below. A summary of the impacts and the control cost calculation sheets are located in Attachment I.

1A. SCR economic impacts

The hardware for a SCR system includes catalyst materials; the ammonia system including a vaporizer, storage tank, blower or compressor, and various valves, indicators, and controls; the ammonia injection grid; the SCR reactor housing (containing layers of catalyst); transition ductwork; and a continuous emissions monitoring system. Costs may vary nominally if aqua ammonia or urea is used instead of anhydrous ammonia.

Potential site-specific costs not included but that may be necessary are additional particulate removal equipment and ductwork for a control equipment bypass. Taconite plants often have mechanical particulate removal devices to protect process blowers. If mechanical cleaners are not present, additional gas cleaning may be needed for SCR. Steam boilers often have bypasses on SCR systems to protect them during startup, shutdown, and malfunction conditions, which could damage the SCR catalyst.

The pollution control costs for SCR are calculated in two ways:

1. Tying an SCR reactor into an existing induration furnace pre-heat duct system.

2. Installing an SCR reactor with a re-heat system on the induration waste gas stream.

The calculations show that option 1 has a much lower control cost than option 2. However, for option 1 to be technically feasible, there must be a point in the pellet pre-heat section ductwork that meets the SCR operating temperature range. As mentioned in the technical feasibility step of the evaluation, it is unlikely that the temperature range will be met because the existing preheat systems have not been designed with this in mind. Re-designing the pre-heat section for installation of SCR is outside the intent of BART in accordance with the proposed EPA rulemaking.

Option 2 costs are estimated using EPA cost formulas for a recuperative thermal oxidizer with 70% heat recovery in conjunction with an SCR reactor. An actual design would most likely include a duct burner to re-heat the waste gas and a heat exchanger for heat recovery. Waste gas re-heat is required because the exhaust gas is too cool for SCR operating temperature.

One potential option for reducing the cost of waste gas re-heat is installation of a heat exchanger to recover heat from the pellet cooler exhaust. In addition to a heat exchanger, this option could incur significant costs for duct work and larger air blowers. The potential for fouling the exchanger from dust should also be evaluated. Each facility will have to determine if this option is feasible on a site-specific basis.

The model calculations, assuming a 90% NOx reduction, suggest that further investigation of Option 2 is warranted in the grate/kiln high inlet NOx concentration (175 ppm) case. Note that the model calculations for the low inlet NOx concentration (50 ppm) case may be low, since it may be difficult to achieve a 90% reduction due to the low NOx concentration at the SCR inlet.

1B. SCR environmental impacts

Undesirable reactions can occur in an SCR process, including the oxidation of NH_3 and SO_2 to form sulfate salts. These compounds are corrosive and can be deposited on the exhaust duct walls. In addition, ammonium sulfate and ammonium bisulfate condense at temperatures below 400 °F, forming white solids, which will increase particulate emissions.

Ammonia slip, or un-reacted ammonia, is also a problem with SCR. Ammonia concentrations in the exhaust gas are typically in the 5-ppm to 10-ppm range. Ammonia can react with sulfur and nitrogen oxides to form fine particulate matter that contributes to haze. In addition, storage of anhydrous ammonia can pose some environmental and safety risks associated with the potential for an accidental release. Aqua ammonia and urea may be substituted for ammonia; but these systems have higher capital and operating costs than anhydrous ammonia.

Ammonia also poses potential water quality issues. Ammonia slip released to the atmosphere could contaminate surface waters by deposition. If an induration waste gas scrubber is used, excess ammonia would be absorbed by the scrubber. This could contaminate the tailings basin as water is recycled from the tailings basin to the plant.

1C. SCR energy impacts

Additional natural gas may be required if a duct burner is needed to maintain proper catalyst bed temperatures.

2A and 3A. Low-NOx and IFGR burner economic impacts.

The cost for installation of new burners is assumed to be relatively low. This estimate assumes a minor amount of refractory work and natural gas piping revisions will be needed. Two burner sizes were evaluated to reflect the range of burner that may be installed.

Low-NOx and IFGR burner tiles can be significantly larger than standard burner tiles, leading to extensive refractory work. Sometimes the size of the burner tile can be large enough to require structural changes to the furnace. These factors should be evaluated in the site-specific analysis.

Low-NOx and IFGR Burners typically have longer flame patterns than standard burners. The impact of longer flames should be evaluated when considering the cost of installation for these burners.

Installation of low NOx Burners is a potential option if the induration furnace uses gas burners to pre-heat the pellets. The NOx reductions for this case are based an emission factor of 0.14 lb NOx per MMBtu of gas firing and control efficiencies of 25% and 50% for Low-NOx and IFGR burners, respectively.[20] Pyrolysis heaters operate in the same temperature range as pellet pre-heating, but with much lower excess air conditions than induration furnaces. So, it is unlikely that the same level of emission reduction in a pyrolysis heater can be achieved in an induration furnace.

The overall reduction in NOx emissions due to low NOx burners must be determined on a site-specific basis. The control efficiency for low NOx burners used in the economic analysis is for the burners themselves, not for the overall induration process. The percentage reduction in total induration furnace NOx emissions will be lower because only a fraction of the total fuels burned in the induration furnace is combusted in low NOx burners. The overall NOx reduction for low NOx burners will be proportional to the percentage of fired duty which is supplied by the low NOx burners. For example, the Low NOx cost calculations show a reduction of 20 to 40 tons per year of NOx from an uncontrolled emission rate of 70 ton/yr NOx for the burners. In contrast, total NOx for the model induration sources ranges from 300 to 13,500 tons of NOx per year.

2B and 3B. Low-NOx and IFGR burner environmental impacts

There are no known adverse environmental impacts associated with these burners.

2C and 3C. Low-NOx and IFGR burner energy impacts

Some IFGR burners are slightly less energy efficient that standard burners. A nominal increase in natural gas consumption may occur.

4A, 4B, and 4C. Ported kilns economic, environmental, and energy impacts

The primary benefits of ported kilns are a 5% reduction in fuel use and an improvement in pellet quality. The main driver for installation of ported kilns is the economic benefit of reduced fuel consumption. Due to the marginal environmental benefits of ported kilns, a cost analysis was not performed.

7.4 *Model Induration Furnace SO_2 Control Technology Review*

SO_2 emissions from the induration furnaces are mostly due to fuel combustion. Some SO_2 may also be emitted from oxidation of sulfur compounds in the iron ore.

As shown in Section 9 of this report, no specific regulatory limits for SO_2 emissions exist for taconite induration furnaces. However, Minnesota rules govern SO_2 emissions from direct-fired equipment, such as induration furnaces, to the following limitations:

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[20] Derived from pyrolysis heaters in "Alternative Control Techniques Document – NOx Emissions from Process Heaters (Revised)," US EPA, EPA-453/R-93-034, September 1993.

- SO_2 emissions from liquid fuels: 2.0 lbs of SO_2 per 1 million BTU.
- SO_2 emissions from solid fuels are limited to 4.0 lbs of SO_2 per 1 million BTU.

These limits can be achieved through fuel quality and do not impact the BART screening evaluation.

7.4.1 BART Step 1: Identify All Available Retrofit Control Technologies

Control technologies available for SO_2 are as follows:

- High-efficiency and low-efficiency wet scrubbers

- Wet walled electrostatic precipitator (WWESP)

See Section 6.2 for additional information on these control technologies and additional technologies identified in the literature search.

7.4.2 BART Step 2: Eliminate Technically Infeasible Options

Both of the control technologies identified in step 1 are deemed technically feasible. The WWESP is currently used to control emissions at some existing taconite induration furnaces. Wet particulate scrubbers, which are similar to the wet scrubbers for SO_2, are also used at some existing induration furnaces.

7.4.3 BART Step 3: Rank Remaining Control Technologies

The technically feasible control technologies and their control efficiencies are presented in Table 7-4.

Table 7-4
Control Technology Rankings for Induration SO_2 Control

Control Technology	Control Efficiency
1. High Efficiency Wet Scrubber	95%
2. Low Efficiency Wet Scrubber	80%
3. WWESP	80%

7.4.4 BART Step 4: Evaluate Impacts and Document the Results

A discussion of relevant impacts, including (A) economic, (B) environmental, and (C) energy, for the technically feasible control technologies is detailed below. A summary of the impacts and the control cost calculation sheets are located in Attachment J

A. Economic impacts

For the high efficiency and low efficiency wet scrubber, the control cost calculations are prepared using caustic as the base in the scrubbing liquor. Lime and limestone are potential alternatives for a scrubber; but additional equipment will be needed for slurry preparation and for solids separation from the sludge generated in the scrubber. Materials of construction must also be made suitable for caustic, lime, or limestone if existing equipment is modified for wet scrubbing of SO_2.

Both the low efficiency wet scrubber and the WWESP have the option of being used to control SO_2 and PM. To account for this dual pollutant-control purpose, two example cost calculations are presented in Attachment J. These tables calculate the control cost based on the removal of both SO_2 and PM at nominal control efficiencies. Note that this may not be achievable in practice for existing equipment if the materials of construction are not appropriate for caustic, lime, or limestone addition. Lime and limestone have the added problems of high solids content scrubbing liquor and sludge separation.

Model source control costs for a straight grate furnace are very high due to the low inlet concentration of SO_2. These furnaces are generally fired on natural gas. Similarly, source control costs are high for most grate/kiln furnaces with low inlet SO_2 waste gas concentrations. For those grate/kiln furnaces with high SO_2 waste gas concentrations, control costs appear to be similar for wet scrubbers and WWESPs. Facilities should evaluate the control option that best fits their existing infrastructure in order to minimize overall control costs.

B. Environmental impacts

The primary environmental impact of wet scrubbers is the generation of wastewater and sludge. Waste from the scrubber will increase the sulfate and solids loading in the facility's wastewater. This places additional burdens on a facility's wastewater treatment and solid waste management capabilities. These impacts will need to be analyzed on a site-specific basis. If lime or limestone scrubbing is used to produce calcium sulfite sludge, the sludge is water-laden, and it must be stabilized for land filling. If lime or limestone scrubbing is used to produce calcium sulfate sludge, it is stable and easy to dewater. However, control costs will be higher because additional equipment is required.

Scrubber and WWESP exhaust gases are saturated with water, thus creating a visible plume. Plume visibility may be a local/community concern. Once the exhaust mixes with sufficient air, the moisture droplets evaporate, and the plume is no longer visible.

C. Energy impacts

A scrubber operates with a high pressure drop, resulting in a significant amount of electricity required to operate the blower and pump. In comparison, the WWESP has a lower pressure drop requirement than the scrubber and the cost to operate the electrical field is not as significant as the electrical costs for the wet scrubber.

7.5 *Model Induration Furnace PM Control Technology Review*

Particulate matter emissions emanate from both fuel combustion, especially if a solid fuel is used, and the attrition of particles (dust) in the taconite pellets.

Federal and State regulations govern PM emissions at taconite induration furnaces. Table 7-5 summarizes applicable emission limits.

Table 7-5
Applicable PM and Opacity Emission Limitations at Taconite Induration Furnaces

Pollutant	Emission Limit	Regulatory Reference
Particulate Matter	0.010 gr/dscf existing straight grate induration processing magnetite	Proposed 40 CFR 63 Subpart RRRRR – MACT
Particulate Matter	0.011 gr/dscf existing grate/kiln induration processing magnetite	Proposed 40 CFR 63 Subpart RRRRR – MACT
Particulate Matter	0.026 gr/dscf existing grate/kiln induration processing hematite	Proposed 40 CFR 63 Subpart RRRRR – MACT
Visible Emissions	20% opacity	MN 7011.7010 & 7015 Pre & Post 1969 Industrial Process Rules
Particulate Matter	0.02 to 0.3 gr/dscf Limit based on exhaust flow and production capacity	MN 7011.7010 & 7015 Pre & Post 1969 Industrial Process Rules

7.5.1 BART Step 1: Identify All Available Retrofit Control Technologies

Control technologies available for PM are as follows:

- High Efficiency and Low Efficiency Wet Scrubber
- Dry Electrostatic Precipitator (ESP)
- Wet Wall Electrostatic Precipitator (WWESP)
- Fabric Filter (Baghouse)
- Multiclone

See Section 6.3 for additional information on these control technologies and additional technologies identified in the literature search.

7.5.2 BART Step 2: Eliminate Technically Infeasible Options

All control technologies identified in step 1 are deemed technically feasible except for the fabric filters (baghouses). Many sources currently use wet particulate scrubbers or WWESPs.

Fabric filters are infeasible in this application due to filter blinding associated with water condensation. Currently, no taconite plants in the United States use fabric filters for particulate control on induration furnaces. The process designs for induration furnaces include provisions for energy recovery by using hot process gas to pre-heat and dry the incoming green taconite pellets. To maximize energy recovery, the furnaces were designed so that gases leaving the induration furnace are typically in the 100 °F to 150 °F range. This leaves the stack gases at or very near their dew points. Any free water present in the induration furnace waste gas or water condensation on the filter media would create a wet and sticky filter cake that would not be easily be removed from the filters. Other control technology options that are technically feasible can provide comparable emission control efficiency; therefore, elimination of fabric filter technology will not significantly affect the BART screening evaluation.

7.5.3 BART Step 3: Rank Remaining Control Technologies

The third of the five steps in the top-down BART analysis is to rank the remaining control technologies by control effectiveness. The remaining control technologies and their control efficiencies are presented in Table 7-6.

Table 7-6
Control Technology Rankings for Induration PM Control

Control Technology	Control Efficiency
1. Dry ESP	98%-99+%
2. WWESP	98%-99+%
3. Wet Scrubber High Efficiency	95%-99+%
4. Wet Scrubber Low Efficiency	90%-95%
5. Multiclone	50%-80%

7.5.4 BART Step 4: Evaluate Impacts and Document the Results

A discussion of relevant impacts, including (A) economic, (B) environmental, and (C) energy, for each of the five technically feasible control technologies is detailed below. A summary of the impacts and the control cost calculation sheets are located in Attachment K.

A. Economic impacts

Model source control costs for a straight grate furnace are high due to the low inlet concentration of PM. These furnaces are generally fired on natural gas. Model source control costs for grate/kiln furnaces were lower due to higher PM concentrations in the induration waste gas. Control costs for ESP appear to be significantly higher than other PM control technologies.

Note that the same capital cost estimate is used for high efficiency and low efficiency scrubbers. Based on an analysis performed in 2001 for a potential new taconite plant, the cost differentiation between high efficiency and low efficiency scrubbers is insignificant. In practice, a low efficiency scrubber will have a lower capital cost than a high efficiency scrubber, but the cost difference will likely not be significant.

Another cost consideration is the estimated PM10 removal efficiency for multiclones. The BART screening evaluation uses 80% control efficiency to determine the control cost. Cyclones generally do not control fine particulate matter as well as other PM control technologies. Vendor guarantees for control efficiency should be verified; especially when multiclone inlet PM loading consists primarily of fine particulate matter. Particle size distribution for the waste gas steam may be necessary to accurately predict the particulate matter control efficiency. In some cases, the waste gas inlet PM concentrations may be below the level necessary for a multiclone to effectively remove PM.

As noted in the BART screening evaluation for SO_2 emissions, both wet scrubbers and WWESPs may potentially be used to remove both PM and SO_2. The option should be considered in the site-specific BART analysis.

B. Environmental impacts

The primary environmental impact of wet scrubbers is the generation of wastewater and sludge. Waste from the scrubber will increase the sulfate and solids loading in the facility's wastewater. This places additional burdens on a facility's wastewater treatment and solid waste management capabilities. These impacts will need to be analyzed on a site-specific basis.

Scrubber and WWESP exhaust gases are saturated with water, thus creating a visible plume. Plume visibility may be a local/community concern. Once the exhaust mixes with sufficient air, the moisture droplets evaporate, and the plume is no longer visible.

A dry ESP and a multiclone will both generate solid waste from the material collected in the associated hopper.

C. Energy impacts

A scrubber operates with a high pressure drop, resulting in a significant amount of electricity required to operate the blower and pump. In comparison, the WWESP has a lower pressure drop requirement than the scrubber and the cost to operate the electrical field is not as significant as the electrical costs for the wet scrubber. Similarly, a relatively modest amount of electricity is required for multiclone blower operation.

7.6 *Model Pellet Cooler PM Control Technology Review*

Particulate matter emissions emanate primarily from the attrition of particles (dust) in the taconite pellets.

Table 7-5 lists PM and opacity emission limitations at taconite induration furnaces. The proposed Taconite MACT standards in this table do not apply to pellet cooler vent stacks. However, the Minnesota rules regulating industrial process equipment, as shown in this table, is applicable to the pellet coolers.

The control technology review for pellet cooler PM emissions is similar to the review for induration PM emissions in Section 6.3.

7.6.1 BART Step 1: Identify All Available Retrofit Control Technologies

Control technologies available for PM are the same as those identified in Section 7.5.1 for the model induration furnace. These technologies are as follows:

- High Efficiency and Low Efficiency Wet Scrubber
- Dry Electrostatic Precipitator (ESP)
- Wet Wall Electrostatic Precipitator (WWESP)
- Fabric Filter (Baghouse)
- Multiclone

See Section 6.3 for additional information on these control technologies and additional technologies identified in the literature search.

7.6.2 BART Step 2: Eliminate Technically Infeasible Options

All control technologies identified in step 1 are deemed technically feasible. However, if an existing pellet cooler uses a wet scrubber or WWESP, a fabric filter is technically infeasible for the same basis as that described in Section 7.5.2 for a fabric filter on an induration furnace. Note that the wet scrubber or WWESP would already control PM emissions to a level similar to a fabric filter.

7.6.3 BART Step 3: Rank Remaining Control Technologies

The third of the five steps in the top-down BART analysis is to rank the remaining control technologies by control effectiveness. The remaining control technologies and their control efficiencies are presented in Table 7-7.

Table 7-7
Control Technology Rankings for Pellet Cooler PM Control

Control Technology	Control Efficiency
1. Fabric Filter	98%-99+%
2. Dry ESP	98%-99+%
3. WWESP	98%-99+%
4. Wet Scrubber High Efficiency	95%-99+%
5. Wet Scrubber Low Efficiency	90%-95%
6. Multiclone	50%-80%

7.6.4 BART Step 4: Evaluate Impacts and Document the Results

A discussion of relevant impacts, including (A) economic, (B) environmental, and (C) energy, for each of the six technically feasible control technologies is detailed below. A summary of the impacts and the control cost calculation sheets are located in Attachment L.

A. Economic impacts

Model source control costs for pellet coolers are relatively low due to significant PM inlet loading at the pellet cooler exhaust. Control costs seem to be similar between the different control types. Facilities should evaluate the control option that best fits their existing infrastructure in order to minimize overall control costs. Actual control costs will be higher than the model source for those emission units that have existing controls and resultant lower PM loadings.

Note that the same capital cost estimate is used for high efficiency and low efficiency scrubbers. Based on an analysis performed in 2001 for a potential new taconite plant, the cost differentiation between high efficiency and low efficiency scrubbers is insignificant. In practice, a low efficiency scrubber will have a lower capital cost than a high efficiency scrubber, but the cost difference will likely not be significant.

Another cost consideration is the estimated PM10 removal efficiency for multiclones. The BART screening evaluation uses 80% control efficiency to determine the control cost. Cyclones generally do not control fine particulate matter as well as other PM control technologies. Vendor guarantees for control efficiency should be verified; especially when multiclone inlet PM loading consists primarily of fine particulate matter. In some cases, the waste gas inlet PM concentrations may be below the level necessary for a multiclone to effectively remove PM.

B. Environmental impacts

The primary environmental impact of wet scrubbers is the generation of wastewater and sludge. Waste from the scrubber will increase the sulfate and solids loading in the facility's wastewater. This places additional burdens on a facility's wastewater treatment and solid waste management capabilities. These impacts will need to be analyzed on a site-specific basis.

Scrubber and WWESP exhaust gases are saturated with water, thus creating a visible plume. Plume visibility may be a local/community concern. Once the exhaust mixes with sufficient air, the moisture droplets evaporate, and the plume is no longer visible.
A dry ESP, multiclone, and fabric filter will all generate solid waste from the material collected in the associated hopper.

C. Energy impacts
A scrubber operates with a high pressure drop, resulting in a significant amount of electricity required to operate the blower and pump. In comparison, the WWESP has a lower pressure drop requirement than the scrubber and the cost to operate the electrical field is not as significant as the electrical costs for the wet scrubber. Similarly, a relatively modest amount of electricity is required for multiclone and fabric filter blower operation.

7.7 *Model Material Ore Material Handling PM Control Technology Review*

Material handling, crushing, and screening activities are grouped together for the model BART screening evaluation. Physical characteristics of the model iron ore material handling source are described in Table 7-1.

Federal and State regulations govern PM emissions at material handling sources. Table 7-8 summarizes applicable emission limits. In addition, Minnesota rules and the proposed taconite MACT require a fugitive dust control plan.

Table 7-8
Applicable PM and Opacity Emission Limitations at Ore Material Handling Sources.

Pollutant	Emission Limit	Regulatory Reference
Particulate Matter	0.02 gr/dscf	40 CFR 60.382(a)(1) - NSPS
Visible Emissions	7% opacity from process point sources (exemption for wet scrubber)	40 CFR 60.382(a)(2) - NSPS
Visible Emissions	10% opacity from process fugitive sources	40 CFR 60.382(b) - NSPS
Particulate Matter	0.008 gr/dscf at an existing source	Proposed 40 CFR 63 Subpart RRRRR – MACT
Visible Emissions	20% opacity	MN 7011.7010 & 7015 Pre & Post 1969 Industrial Process Rules
Particulate Matter	0.02 to 0.3 gr/dscf Limit based on exhaust flow and production capacity	MN 7011.7010 & 7015 Pre & Post 1969 Industrial Process Rules

7.7.1 BART Step 1: Identify All Available Retrofit Control Technologies

Control technologies available for PM are as follows:

- High Efficiency and Low Efficiency Wet Scrubber
- Dry Electrostatic Precipitator (ESP)
- Wet Wall Electrostatic Precipitator (WWESP)
- Fabric Filter (Baghouse)
- Multiclone
- Enclosure
- Wet Suppression
- Best Management Practices

See Section 6.3 for additional information on these control technologies and additional technologies identified in the literature search.

7.7.2 BART Step 2: Eliminate Technically Infeasible Options

Table 7-9 summarizes the technical feasibility of each available control technology to ore material handling sources.

Table 7-9
Summary of Technical Feasibility for Ore Material Handling PM Emissions

Control Technology	Feasibility Determination	Issues That Affect Control Technology Feasibility
1. Wet Scrubber High & Low Efficiency	Conditionally Feasible	It must be feasible to enclose the source and duct the exhaust to the control device.
2. Dry ESP	Conditionally Feasible	It must be feasible to enclose the source and duct the exhaust to the control device.
3. WWESP	Conditionally Feasible	It must be feasible to enclose the source and duct the exhaust to the control device.
4. Fabric Filter (Baghouse)	Conditionally Feasible	It must be feasible to enclose the source and duct the exhaust to the control device.
5. Multiclone	Conditionally Feasible	It must be feasible to enclose the source and duct the exhaust to the control device.
6. Enclosure	Conditionally Feasible	Feasible for conveyor drops into processing equipment on onto other conveyors. Not feasible for conveyor drops onto large storage piles. Telescoping chutes may be feasible.
7. Wet Suppression	Conditionally Feasible	For use on fugitive sources such as storage piles. Effectiveness will be limited in active areas where material surfaces are disturbed on a frequent basis. May also be used on conveyors to bind up particulates before the transfer material is dropped off the conveyor.21
8. Best Management Practices	Conditionally Feasible	For use on fugitive sources such as storage piles.

Some material handling sources utilize existing wet scrubbers. In this case, there will be water mist in the exhaust, and the used of fabric filters is infeasible.

7.7.3 BART Step 3: Rank Remaining Control Technologies

The third of the five steps in the top-down BART analysis is to rank the remaining control technologies by control effectiveness. The remaining control technologies and their control efficiencies are presented in Table 7-10.

Table 7-10
Control Technology Rankings for Ore Material Handling PM Control

Control Technology	Control Efficiency
1. Fabric Filter	98%-99+%
2. Dry ESP	98%-99+%
3. WWESP	98%-99+%
4. Wet Scrubber High Efficiency	95%-99+%
5. Wet Scrubber Low Efficiency	90%-95%
6. Chemical Stabilization	75%-80%
7. Multiclone	50%-80%
8. Enclosure (Windbreaks may also be used to minimize the impact of wind entrainment of particulates.)	50%-100%
9. Wet Suppression	50%-75%
10. Best Management Practices (e.g., minimize drop heights, work on lee side of piles, minimize disturbed area)	Variable

7.7.4 BART Step 4: Evaluate Impacts and Document the Results

A discussion of relevant impacts, including (A) economic, (B) environmental, and (C) energy, for each of the four technically feasible control technologies is detailed below. A summary of the impacts and the control cost calculation sheets are located in Attachment M.

A. Economic impacts

The emission basis for this model source is the AP-42 factor for uncontrolled drops of aggregate materials (i.e. iron ore). The same baseline emission rate is used for all control options.

Enclosures and multiclones have the lowest control costs for the model source. Dry and wet walled ESPs have the highest control costs. The multiclone estimate was based on grouping ten sources together because the multiclone vendor could not prepare a quote for such a small source. Where applicable, data from the cost analysis table (M-7) summary table was divided by 10 in the summary table (M-1) so that the information would be comparable to the other control methods. An 80% control efficiency was assumed for multiclone control cost calculations. Actual control efficiencies are likely to be lower; so, vendor control efficiency guarantees should be obtained for the site-specific analysis.

The cost control estimates for control equipment assumes that an enclosure is in place to connect the emission unit to the control device. If an uncontrolled source without an enclosure is evaluated, the control cost should include the cost of an enclosure.

Many facilities currently control emissions from conveyor drops. Often, several sources are ducted to a single control device. This reduces overall control costs by taking advantage of the economy of scale for a relatively expensive piece of control equipment. Facilities should consider this option when evaluating their material handing emissions.

Control costs are not calculated for wet suppression or best management practices. Most facilities have already incorporated these practices into their particulate control plans.

B. Environmental impacts

The primary environmental impact of wet scrubbers is the generation of wastewater and sludge. Waste from the scrubber will increase the sulfate and solids loading in the facility's wastewater. This places additional burdens on a facility's wastewater treatment and solid waste management capabilities. These impacts will need to be analyzed on a site-specific basis.

Scrubber and WWESP exhaust gases are saturated with water, thus creating a visible plume. Plume visibility may be a local/community concern. Once the exhaust mixes with sufficient air, the moisture droplets evaporate, and the plume is no longer visible.

A dry ESP, multiclone, and fabric filter will all generate solid waste from the material collected in the associated hopper.

C. Energy impacts

A scrubber operates with a high pressure drop, resulting in a significant amount of electricity required to operate the blower and pump. In comparison, the WWESP has a lower pressure drop requirement than the scrubber and the cost to operate the electrical field is not as significant as the electrical costs for the wet scrubber. Similarly, a relatively modest amount of electricity is required for multiclone and fabric filter blower operation.

7.8 *Fugitive Dust Emissions*

Fugitive dust emissions occur from the mechanical disturbance of granular material exposed to the air. These emissions are termed "fugitive" because that are not discharged to the atmosphere in a confined flow stream. The dust-generation process is caused by two basic physical phenomena:

1. Pulverization and abrasion of surface materials by application of mechanical force through implements.

2. Entrainment of dust particles by the action of turbulent air currents.

Sources of fugitive emission at taconite plans include unpaved roads, storage piles, loading and unloading operations, tailings basins, and drops.

Control methods for fugitive emissions are listed in this section for informational purposes only. Most fugitive particulate emissions occur in the mining area, which is considered outside the scope of this screening BART analysis. It is also anticipated that fugitive emissions will not disperse great distances to impact visibility in a Class I area.

Minn. Rule 7011.0150 requires sources to control fugitive particulate emissions at their facilities. Minn. Rule 7007.0800 establishes particulate control requirements in the facility's operating (Title V) permit.

Available control technologies for PM control from fugitive dust emissions are identified in Table 7-11.

Table 7-11
Available PM Control Technologies for Fugitive Sources

Process	Control Technology
1. Vehicle Traffic	Wet Suppression Physical Stabilization Cover Roads with Low Silt Gravel Paved Surface Cleaning Limit speeds and area of travel
2. Overburden Wind Erosion and Waste Rock Wind Erosion	Minimize the Area of Disturbance Physical Stabilization Vegetative Stabilization Wind Breaks – fences, soil mounds or trees
3. Tailings Basin	Physical Stabilization Vegetative Stabilization Wet Suppression

All taconite plants have fugitive dust control plans in place, as required by Minn. Rule 7011.0150. The plans include control measures like the ones listed above to manage fugitive emissions. The control plans updated and reviewed by MPCA as part of the Title V permit re-issuance process that occurs every five years.

8 Affordability

BART development provides for an affordability analysis of the proposed case-by-case BART evaluation. The affordability analysis is to consider the effects of BART on the viability of continued plant operations. This analysis may allow that the total cost of a BART program at the plant be considered as discussed below. Financial information adequate to assess the viability of the BART program must also be provided. The affordability analysis will then need to include an evaluation of the economic impacts of the proposed BART alternative to the source under consideration. The analysis will need to be in sufficient detail to provide a compelling argument regarding the plant viability for the proposed BART.

8.1 *BART Alternative Cost Inventory*

Total costs associated with a BART alternative can be considered in an affordability analysis. Items to consider in developing a total cost inventory may include:

> *Control Associated Costs*. These include capital costs and operation and maintenance costs associated with the BART alternative. It may include water and solids management, energy and other costs that are also directly associated with the control alternative. This is discussed in Section 7. Several members of the taconite industry and the industry organization were contacted to ascertain their perspectives. The industry representatives are unable to predict whether the controls likely to be required to meet BART would be more stringent than existing or imminent future requirements. Without knowing the level of control BART would require, they were unable to provide any information on its affordability.

> *Compliance Associated Costs*. This includes the costs required to demonstrate compliance with the proposed BART emissions limit or operating practice. Examples include additional emissions testing, operations monitoring, records management, and compliance reporting related costs for the proposed BART alternative. Several members of the taconite industry and the industry organization were contacted to ascertain their perspectives. The industry representatives are unable to predict whether the monitoring and testing likely to be required to meet BART would be more stringent than existing or imminent future requirements. Without knowing the level of monitoring BART would require, they were unable to provide any information on its affordability.

> *Supplier Price Increases*. The Regional Haze program is likely to require air emissions reductions at suppliers to the taconite industry. It is possible that supplier's product prices may be increased to recover the costs of their emission reduction efforts. These price increases may be considered in determining the affordability of proposed emissions reduction alternatives under consideration in establishing BART for the taconite plants. Major potentially affected suppliers include fossil fuels and electricity. Electric and petroleum fuel producers that are the major suppliers of these services to the Minnesota taconite industry were contacted. However, they were unable to provide an estimate of the costs of the Regional Haze program or potential product price increases at this time due to the uncertainties and long time-line associated with implementation of the Regional Haze program.

Other BART Related Costs. Any other costs that would be attributed to the BART program and that may affect the viability of the organization may also be included in the cost inventory.

8.2 *Financial Information Inventory*

Significant resources within the Minnesota taconite industry are in bankruptcy or on the verge of it. The industry faces tough competition from foreign sources.[21] The US mines have higher production costs in part because of the higher cost of labor and greater taxation. The high cost of transportation through the St. Lawrence Seaway prevents US taconite from entering the world steel market and levels the playing field somewhat with foreign taconite destined for US steelmakers, although the delivered cost of foreign taconite remains cheaper.

The cost of closing a taconite mine essentially traps producers into operating their mines well past what their operating costs would justify.[22] Environmental and employee closure costs are significant. Environmental closure costs are expected to be postponed, passed on to the next operator, or be foregone in a final bankruptcy liquidation. Retirement and health care costs for employees at closure are expected to be delayed by continuing to operate mines even after they become unprofitable. The US government may step in, but so far has not. If a BART program led to significant cost increases, the viability of the industry would be seriously threatened.

Broad industry related financial information and plant specific information that is current at the time of the site-specific affordability analysis will be required. This should include the following information:

Financial Statements. A description of the plant ownership should be provided along with the financial statement of each corporation that has an ownership stake in the plant.

Financial Reports for the Individual Taconite Plant. At a minimum, the current balance sheet, income statement, and cash flow statement should be provided.

Independent Market Analysis of the Industry. This includes a long term and short tem analysis completed by an independent entity.

Other Relevant Information. Other relevant information as necessary to support the argument regarding viability concerns of the entity under consideration. Relevant information to evaluate effects on market share, product prices, and profitability should be considered.

8.3 *Affordability Evaluation Summary*

The affordability evaluation will be required to make a compelling argument regarding the plant viability based on information that is current at the time of the BART-decision making process. The analysis will likely involve the review and presentation of sensitive business information. To

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[21] *Cost Comparison for North American Iron Ore Mines – Part II*, Skillings Mining Review, December 2002.
[22] IBID

assure the confidentiality of the sensitive information, a confidentiality request must be filed that meets the requirements of Minnesota Statutes.

9 Summary of Existing and Proposed Air Pollution Regulatory Requirements

This section provides a summary of the existing and proposed federal regulations and existing state and Canadian provincial air pollution regulatory requirements that are applicable to the three taconite emission unit categories established in Section 5.8.2. The regulations summarized include:

- 40 CFR 60, Subpart LL – Standards of Performance for Metallic Mineral Processing Plants
- 40 CFR 60, Subpart Y – Standards of Performance for Coal Preparation Plants
- 40 CFR 63, Subpart RRRRR – National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Taconite Iron Ore Processing
- Minnesota Rules, Chapter 7011 – Standards for Stationary Sources
- Michigan Air Pollution Control Rules, Parts 3 through 12
- Canadian provincial air pollution control regulations.

Existing air permits as well as past BACT determinations at the Minnesota taconite plants were also reviewed for any site-specific emission limitations. Findings from the air permit review are included throughout this section and are referred to as permit limits under Minn. R. 7007.0800. See Section 9.7 for a summary of relevant BACT determinations.

The information and findings detailed in this section are summarized in Tables 9-1, 9-2, and 9-3 with respect to each of the three taconite emission unit categories.

Table 9-1
Air Quality Standards for Taconite Fugitive Particulate Sources

Standard	Emission Limit or Site-specific Operating Standard	Comment
40 CFR 60 Subpart LL	10% opacity	
Proposed 40 CFR 63 Subpart RRRRR		Prepare and implement a written fugitive dust emissions control plan
Minn. R. 7007.0800	Observe fugitive dust sources daily	
Minn. R. 7007.0800	Comply with the fugitive control plan	
Minn. R. 7007.0800	Ensure 1 employee trained to perform visible emissions checks	
Minn. R. 7007.0800	Comply with the operation and maintenance plan	
Minn. R. 7011.0150		Avoid particulate matter from becoming airborne
MI R 336.1371		Submit a fugitive dust control program
Quebec		Dust control measures for transport areas
Quebec	50 mg/m^3 or 2 m free fall height	Free fall of materials
Quebec	2 m from source	Dust recuperated by a dry collector

Table 9-2
Air Quality Standards for Taconite Point Particulate Sources

Standard	Emission Limit or Site-specific Operating Standard	Comment
40 CFR 60 Subpart LL	≤ 0.05 g/dscm (0.02 gr/dscf)	
40 CFR 60 Subpart LL	7% opacity	
Proposed 40 CFR 63 Subpart RRRRR	0.005 gr/dscf	From new ore crushing and handling sources and new finished pellet handling sources
Proposed 40 CFR 63 Subpart RRRRR	0.008 gr/dscf	From existing ore crushing and handling sources and existing finished pellet handling sources
Proposed 40 CFR 63 Subpart RRRRR	0.025 gr/dscf	From new ore dryers
Proposed 40 CFR 63 Subpart RRRRR	0.052 gr/dscf	From existing ore dryers
Minn. R. 7007.0800	Comply with the operation and maintenance plan	Applies to total facility
Minn. R. 7007.0800	Operate all pollution control equipment whenever the corresponding process equipment is operated	Applies to total facility
Minn. R. 7007.0800	▪ Install monitoring equipment for air pollution control devices within 180 days of permit issuance ▪ Complete monitoring equipment debugging, troubleshooting, and establishment of parameter ranges within 180 days of installation or of completion of needed repairs of all monitoring equipment ▪ Annually calibrate all required monitoring equipment	Applies to total facility
Minn. R. 7007.0800	Check stack opacity once daily	Applies to crushers, screens, conveyors, bins, blenders, grates, coolers, and pellet discharges
Minn. R.	Monitor gas stream pressure drop daily when	Applies to fabric filters, multiclones,

Table 9-2
Air Quality Standards for Taconite Point Particulate Sources

Standard	Emission Limit or Site-specific Operating Standard	Comment
7007.0800	in operation	scrubbers, gravity collectors
Minn. R. 7007.0800	Monitor gas stream pressure drop weekly when in operation	Applies to fabric filters, multiclones, scrubbers, gravity collectors
Minn. R. 7007.0800	Monitor water flow rate or total water pressure daily when in operation	Applies to scrubbers
Minn. R. 7007.0800	Monitor water flow rate or total water pressure weekly when in operation	Applies to scrubbers
Minn. R. 7007.0800	For units controlled by fabric filters, cyclones, and multiclones: ▪ check pressure drop daily if visible emissions in the plume are unreadable due to visible moisture For units controlled by scrubbers: ▪ check pressure drop and total water pressure if visible emissions in the plume are unreadable due to visible moisture	Applies to fabric filters, cyclones, multiclones, and scrubbers
Minn. R. 7007.0800	▪ Operate the ambient monitors, during the first 12 months of haul road operation after permit issuance, to establish the operating conditions and control practices necessary to maintain PM-10 concentrations at those monitors below the NAAQS and MAAQS. ▪ The conditions and control practices identified during this period shall be incorporated into the Fugitive Control Plan for the facility. ▪ Immediately after the time period described above, operate the monitors on a continuous 1 in 6 day sampling schedule to determine compliance with the NAAQS and MAAQS. ▪ The monitors must be operated until data is obtained, from a total of 12 months of haul road operation that is below the NAAQS and MAAQS. After this has been achieved the Permittee can discontinue operating the monitors after notifying the MPCA 14 days in advance of the date the monitors will be shut down.	Applies to total facility

Table 9-2
Air Quality Standards for Taconite Point Particulate Sources

Standard	Emission Limit or Site-specific Operating Standard	Comment
Minn. R. 7007.0800	Allowed to change the location of the pickup points to improve collection of particulates. If an effective location for the pickup points can not be found, scrubber may be removed from service without a permit as long as the unrestricted net emission change due to this action is not over the significant emission rates for PSD	Applies to total facility
Minn. R. 7007.0800	For each baghouse either, 1) make daily visible emission checks or pressure drop readings when visible emission checks can not be performed, or 2) operate a broken bag detector	Applies to fabric filters
Minn. R. 7011.0710	See process weight rate table (7011.0730 Table 1)	Applicable to pre-1969 industrial process equipment
Minn. R. 7011.0710	20% opacity	An exceedance of this opacity standard occurs whenever any one-hour period contains two or more six-minute periods during which the average opacity exceeds 20 percent or whenever any one-hour period contains one or more six-minute periods during which the average opacity exceeds 60 percent
Minn. R. 7011.0715	See process weight rate table (7011.0730, Table 1)	Applicable to post-1969 industrial process equipment
Minn. R. 7011.0715	20% opacity	An exceedance occurs whenever any one-hour period contains one or more six-minute periods during which the average opacity exceeds 20 percent
MI R 336.1301	20% opacity	6-minute average
MI R 336.1331	See process weight rate table (Part 3, Table 32)	
Newfoundland 957/96	Opacity: No. 1 on visible emission chart	Except No. 2 for $\leq$ 4 min in 30 min period
Ontario	Opacity: No. 1 on visible emission chart or 20%	
Ontario	100 µg PM/m^3	At point of impingement; one-half hour averaging period

Table 9-2
Air Quality Standards for Taconite Point Particulate Sources

Standard	Emission Limit or Site-specific Operating Standard	Comment
Quebec	20% opacity	Except 40% for $\leq$ 4 min in 60 min period
Quebec	See schedules A and B	
Quebec	50 mg/m^3	Material handling operations

Table 9-3
Air Quality Standards for Taconite Induration Sources

Standard	Emission Limit or Site-specific Operating Standard	Comment
Proposed 40 CFR 63 Subpart RRRRR	0.006 gr/dscf	From new Straight Grate Indurating Furnaces (processing magnetite)
Proposed 40 CFR 63 Subpart RRRRR	0.010 gr/dscf	From existing Straight Grate Indurating Furnaces (processing magnetite)
Proposed 40 CFR 63 Subpart RRRRR	0.006 gr/dscf	From new grate kiln indurating furnaces (processing magnetite)
Proposed 40 CFR 63 Subpart RRRRR	0.011 gr/dscf	From existing grate kiln indurating furnaces (processing magnetite)
Proposed 40 CFR 63 Subpart RRRRR	0.018 gr/dscf	From new grate kiln indurating furnaces (processing hematite)
Proposed 40 CFR 63 Subpart RRRRR	0.025 gr/dscf	From existing grate kiln indurating furnaces (processing hematite)
Minn. R. 7007.0800	Operate all pollution control equipment whenever the corresponding process equipment is operated	
Minn. R. 7007.0800	▪ Install monitoring equipment for air pollution control devices within 180 days of permit issuance ▪ Complete monitoring equipment debugging, troubleshooting, and establishment of parameter ranges within 180 days of installation or of completion of needed repairs of all monitoring equipment ▪ Annually calibrate all required monitoring equipment	
Minn. R. 7007.0800	Limit fuel use to natural gas and distillate oil	

Table 9-3
Air Quality Standards for Taconite Induration Sources

Standard	Emission Limit or Site-specific Operating Standard	Comment
Minn. R. 7007.0800	Limit fuel use to pulverized coal, coal/coke blend, distillate oil, and natural gas	
Minn. R. 7007.0800	▪ Collect a solid fuel sample each weekday from the pulverized fuel pipe ▪ Form a weekly composite of all samples collected in a given calendar week ▪ Analyze the weekly fuel composite samples for sulfur content in weight percent and heating value in Btu/lb	
Minn. R. 7007.0800	Combust only natural gas, all grades of fuel oil, and used oil in these emission units	
Minn. R. 7007.0800	If the average total NOx emission rate exceeds 95% of the NOx emission limit in any 12-month period, submit a plan for Agency review and approval to implement further monitoring that is technically and economically feasible based on current technologies. This monitoring could include CEMS or PEMS	
Minn. R. 7007.0800	Combust only natural gas, step-specific biomass, and/or fuel oil	
Minn. R. 7011.0610	20% opacity or PM process weight rate in 7011.0700-0735	
Minn. R. 7011.0610	4 lb SO_2/MMBtu for solid fuels, 2 lb SO_2/MMBtu for liquid fuels	Applies if the total facility-wide rated heat input of all indirect and direct heating equipment is greater than 250 MMBtu/hr
MI R 336.1301	20% opacity	6-minute average
MI R 336.1331	0.20 lb PM/1,000 lb gas	Grate kilns and traveling grates with a gas flow rate 0-100,000 scfm
MI R 336.1331	0.15 lb PM/1,000 lb gas	Grate kilns and traveling grates with a gas flow rate 100,000-300,000 scfm
MI R 336.1331	0.10 lb PM/1,000 lb gas	Grate kilns and traveling grates with a gas flow rate 300,000-600,000 scfm
MI R 336.1331	Apply to MDEQ for specific emission limit	Grate kilns and traveling grates with a gas flow rate > 600,000 scfm

Table 9-3
Air Quality Standards for Taconite Induration Sources

Standard	Emission Limit or Site-specific Operating Standard	Comment
MI R 336.1331	PM: process weight rate	
MI R 336.1402	1.7 lb SO_2/MMBtu oil	
MI R 336.1402	2.4 lb SO_2/MMBtu coal	
MI R 336.1702		Permitted VOC limit for any existing source
MI R 336.1702		VOC from any new source must be less than lowest maximum allowable emission rate of the following: (a) rate listed by MDEQ on its own initiative or based upon the application of the BACT (b) rate specified by a NSPS (c) rate specified in a permit
MI R 336.1801	Submit a proposal for NOx	Fossil fuel-fired emission unit > 250 MMBtu/hr with a PTE > 25 tons NOx for each ozone control period
Newfoundland 957/96	Opacity: No. 1 on visible emission chart	Except: ▪ No. 2 for ≤ 4 min in 30 min period ▪ No. 3 where a new fire is started in combustion process
Ontario	Opacity: No. 1 on visible emission chart or 20%	Except No. 2, or 40%, for ≤ 4 min in 30 min period from sources combusting solid fuel
Ontario	100 µg PM/m^3	At point of impingement; one-half hour averaging period
Ontario	830 µg SO_2/m^3	At point of impingement; one-half hour averaging period
Ontario	500 µg NOx/m^3	At point of impingement; one-half hour averaging period
Ontario	3,600 µg ammonia/m^3	At point of impingement; one-half hour averaging period

Table 9-3
Air Quality Standards for Taconite Induration Sources

Standard	Emission Limit or Site-specific Operating Standard	Comment
Ontario	200 µg ozone/m^3	At point of impingement; one-half hour averaging period
Ontario	8,000 µg dustfall/m^2	At point of impingement; one-half hour averaging period
Quebec	20% opacity	Except: ▪ 40% for ≤ 4 min in 60 min period ▪ 60% for ≤ 4 min if starting a fire or soot blowing
Quebec	15 kg VOC/day 3 kg VOC/hr	Where photochemically reactive organic compounds are not submitted to a baking process or do not come in contact with a flame
Quebec	1,400 kg VOC/day 200 kg VOC/hr	Where non-photochemically reactive solvents are not submitted to a baking process or do not come in contact with a flame
Quebec	60 mg PM/MJ	New fossil fuel burning equipment 3-15 MW burning gas or oil, or new fossil fuel burning equipment 3-70 MW burning coal
Quebec	85 mg PM/MJ	Existing fossil fuel burning equipment 3-15 MW burning gas or oil, or existing fossil fuel burning equipment 3-70 MW burning coal
Quebec	45 mg PM/MJ	New fossil fuel burning equipment >15 MW burning gas or oil, or new fossil fuel burning equipment >70 MW burning coal
Quebec	60 mg PM/MJ	Existing fossil fuel burning equipment >15 MW burning gas or oil, or existing fossil fuel burning equipment >70 MW burning coal
Quebec	500 ppm NOx (coal), 250 ppm NOx (oil), 200 ppm NOx (gas)	New fuel burning equipment >70 MW
Quebec	450 ppm NOx (coal), 325 ppm NOx (oil), 150 ppm NOx (gas)	New fuel burning equipment 15-70 MW

Table 9-3
Air Quality Standards for Taconite Induration Sources

Standard	Emission Limit or Site-specific Operating Standard	Comment
Quebec	2.0 wt % sulfur content for heavy oil and coal, 1.0 wt % sulfur content for intermediate oil, 0.5 wt % sulfur content for light oil	Liquid and solid fossil fuel combustion units
Quebec	0.10 kg PM/ton of pellets produced	New plant of any capacity
Quebec	0.36 kg PM/ton of pellets produced	Existing plant with production < 1,500,000 tons of iron oxide pellets/yr
Quebec	0.12 kg PM/ton of pellets produced	Existing plant with capacity >/= 1,500,000 tons of iron oxide pellets/yr

9.1 *Federal Standards of Performance for Metallic Mineral Processing Plants*

The information provided in this section is based on 40 CFR Part 60 Subpart LL.

9.1.1 Applicability

A metallic mineral processing plant is any combination of equipment that produces metallic mineral concentrates from ore. Metallic mineral processing begins with the mining of ore and includes all operations up to and including either: (1) the loading of wet or dry concentrates or solutions of metallic minerals for transfer to facilities that will subsequently process the metallic concentrates; or (2) all material transfer and storage operations that precede the operations that produce refined metals (or other products) from metallic mineral concentrates at facilities adjacent to the metallic mineral processing plant.

Subpart LL applies to the following sources in metallic mineral processing plants:

- Each crusher and screen in open-pit mines;[23]
- Each crusher, screen, bucket elevator, conveyor belt transfer point,[24] thermal dryer, product packaging station, storage bin, enclosed storage area, truck loading station, truck unloading station, railcar loading station, and railcar unloading station at the mill or concentrator.

[23] All sources located in underground mines are exempted from the provisions of this subpart.
[24] "Conveyor belt transfer point" excludes by definition any process that transfers the metallic mineral from a conveyor to a stockpile.

The NSPS covers some of the sources that are identified and contained in the fugitive and point PM source categories in Section 5.8.2. Other PM emission sources that are normally found in taconite manufacturing processes and that are not addressed by this NSPS include the following:

- Non-metallic mineral concentrate handling and storage, such as binders (e.g., bentonite), fluxing agents, and other additives
- Solid fuel (e.g., coal and petroleum coke) handling and storage
- Vehicular traffic

Sources that commence construction or modification after August 24, 1982, are subject to the requirements of this subpart. It is possible for a source to be both BART-eligible and subject to NSPS if it was in place between August 7, 1962 and August 7, 1977 and was either modified or reconstructed under NSPS after August 24, 1982. Based on a cursory review of the MPCA BART Survey results and current air permits for the taconite plants, some PM emission sources are both BART-eligible and subject to NSPS subpart LL.

9.1.2 Particulate Matter Standards

Emissions from PM point sources must not:

1. Contain PM in excess of 0.05 grams per dry standard cubic meter (0.02 grains per dry standard cubic foot), or
2. Exhibit greater than 7% opacity, unless a wet scrubber is used.

In addition, emissions from PM fugitive sources must not exhibit greater than 10% opacity.

9.1.3 Compliance Testing and Monitoring

A facility must conduct an initial performance test of a wet scrubber to measure both the change in pressure of the gas stream across the scrubber and the scrubbing liquid flow rate. Facility air permits contain additional monitoring requirements to meet the NSPS limits, including:

- Daily visible emissions checks,
- Daily or weekly gas stream pressure drop monitoring, and
- Daily or weekly liquid flow rate monitoring.

9.2 *Federal Standards of Performance for Coal Preparation Plants, NSPS Subpart Y*

The information provided in this section is based on 40 CFR Part 60 Subpart Y. This subpart applies to sources in coal preparation plants that commence construction or modification after October 24, 1974 and process more than 200 tons per day, including coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems. A coal preparation plant is any facility (excluding underground mining operations) which prepares coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning, and thermal drying. Some taconite facilities that use coal as a fuel source may not be subject to this regulation if they: 1) do not prepare coal per the definition of a coal preparation plant, 2) have facilities that are grandfathered from the rule, or 3) process no more than 200 tons per day. Because coal handling activities will likely be addressed for BART purposes by other organizations representing coal-fired utilities, a detailed analysis for 40 CFR 60 Subpart Y has not been performed.

9.3 *National Emission Standards for Hazardous Air Pollutants for Taconite Iron Ore Processing*

The information provided in this section is based on the final NESHAPs rule in 40 CFR Part 63 Subpart RRRRR that was signed on August 25, 2003, but as of the date of this report had not been published in the Federal Register.

9.3.1 Affected Sources

The proposed rule would currently affect all eight taconite iron ore processing plants in the United States. The affected sources within each plant include all new and existing ore crushing and handling equipment, ore dryers, indurating furnaces, and finished pellet handling. An existing affected source is one constructed or reconstructed on or before December 18, 2002; a new affected source is one constructed or reconstructed after December 18, 2002.

Unlike an NSPS, there is no grandfathering provision to exclude existing equipment from the NESHAPs. Therefore, it is possible for a source to be both BART-eligible and subject to NESHAPs if it was in place between August 7, 1962 and August 7, 1977.

9.3.2 Emission Limits and Work Practice Standards

The proposed rule includes PM emission limits, work practice standards, and operating limits for control devices.

PM serves as a surrogate measure of metallic HAP emissions. The proposed PM emissions limits for affected sources are listed in Table 9-4.

Table 9-4
PM Emission Limits under the Proposed NESHAPs

Source	Proposed PM Emissions Limit for Existing Sources (gr/dscf)	Proposed PM Emissions Limit for New Sources (gr/dscf)
Ore Crushing and Handling	0.008	0.005
Finished Pellet Handling	0.008	0.005
Ore Dryer	0.052	0.025
Straight Grate Indurating Furnace (processing magnetite)	0.01	0.006
Grate Kiln Indurating Furnace (processing magnetite)	0.01	0.006
Grate Kiln Indurating Furnace (processing hematite)	0.03	0.018

The final rule also includes specific requirements for continuous parameter monitoring and associated operating limits for baghouses, wet scrubbers, and dry ESP, described in Table 9-5 below.

Table 9-5
Continuous Parameter Monitoring and Associated Operating Limits

Control Device	Continuous Parameter Monitoring and Associated Operating Limits
Baghouse	Equip with a bag leak detection system (BLDS) capable of monitoring relative changes in PM loading in the baghouse exhaust, which is to alarm whenever a predetermined set point is exceeded, indicating an increase in emissions above that allowed at the set point. Initiate corrective actions within one hour of an alarm.
Wet Scrubber	For dynamic wet scrubbers, monitor scrubber water flow rate and either the fan amperage or pressure drop and operate at all times at or above specified daily average values established during initial performance test. For other wet scrubbers, monitor scrubber water flow rate and pressure drop and operate at all times at or above specified daily average values established during initial performance test.
Dry ESP	Operate continuous opacity monitoring systems (COMS) or maintain daily average secondary voltage and daily average secondary current for each field at or above minimum levels established during the initial performance test

The final rule would require sources to submit information on alternative monitoring parameters and operating limits if a control device other than a baghouse, wet scrubber, or dry ESP is used.

All plants subject to the rule would be required to prepare and implement a written fugitive dust emissions control plan. The plan would describe the measures that will be put in place to control fugitive dust emissions from the following sources at a plant: stockpiles, material transfer points, plant roadways, tailings basin, pellet loading areas, and yard areas. Existing fugitive dust emission control plans that describe current measures to control fugitive dust emission sources that have been approved as part of a SIP or Title V permit would be acceptable, provided they address the fugitive dust emission sources listed above.

The NESHAPs for taconite iron ore processing will establish stringent controls on the induration point sources as well as most of the fugitive and point particulate sources. The limits for existing sources would very likely satisfy BART, since these limits are based on the average emission limitation achieved by the best performing five sources, as required in Section 112(d)(3)(B) of the CAA.

9.3.3 Operation and Maintenance

All plants subject to the proposed rule would be required to prepare and implement a written startup, shutdown, and malfunction plan. In addition, a written operation and maintenance plan would also be required for each control device subject to an operating limit.

9.3.4 Initial Compliance Testing

To demonstrate initial compliance with the PM emission limit for the ore crushing and handling and the finished pellet handling sources, the flow-weighted mean concentration of PM emissions of all units within the affected source must not exceed the applicable PM emission limit. Initial compliance must be demonstrated through a performance test, which must be completed no later than 18 months following the effective compliance date. To demonstrate initial compliance with the PM emission limit for each indurating furnace and each ore dryer, the flow-weighted mean concentration of PM emissions of all stacks for each furnace or each ore dryer must not exceed the applicable PM emission limit. Initial compliance must be demonstrated through a performance test.

The final rule will also require that certain operating limits on control devices be established during the initial compliance test to ensure that control devices operate properly on a continuing basis. All operating limits would be established during a performance test that demonstrates compliance with the applicable emission limit.

To demonstrate initial compliance with the work practice standards, plants would prepare, submit, and implement a fugitive dust emission control plan on or before the applicable compliance date of the rule. To demonstrate initial compliance with the operation and maintenance requirements, plants would certify in their notification of compliance status that they have prepared the written plans and will operate control devices according to the procedures in the plan.

9.3.5 Continuous Compliance

For ore crushing and handling, ore dryers and finished pellet handling units, the rule will require plants to conduct subsequent performance tests to demonstrate continued compliance with the PM emission limits following the schedule established in the Title V permit for each plant. For each induration furnace, the rule requires subsequent testing of all stacks based on the schedule established in each plant's Title V operating permit, but no less frequently than twice per five-year permit term.

Plants are required to monitor operating parameters for control devices subject to operating limits and carry out the procedures in their fugitive dust emissions control plan and their operation and maintenance plan. To demonstrate continuous compliance, plants must keep records documenting compliance with the rule requirements for monitoring, the fugitive dust emissions control plan, the operation and maintenance plan, and installation, operation, and maintenance of a continuous parameter monitoring system (CPMS). To demonstrate continuous compliance for baghouses, the rule will require records of bag leak detection system alarms and records documenting conformance with the operation and maintenance plan, as well as the inspection and maintenance procedures. To demonstrate continuous compliance for scrubbers, plants would keep records documenting conformance with the monitoring requirements and the installation, operation, and maintenance requirements for the CPMS. To demonstrate continuous compliance for dry ESPs, plants must operate and maintain the COMS.

9.3.6 Compliance Deadlines

Existing affected sources must comply within 3 years after publication of the final rule in the Federal Register. New or reconstructed sources that startup on or before the effective date of the final rule must comply by the effective date of the final rule. New or reconstructed sources that startup after the effective date of the final rule must comply upon initial startup.

9.4 *Minnesota Rules, Chapter 7011, Standards for Stationary Sources*

The information provided in this section is based on Minn. R. Chapter 7011, and addresses specifically standards of performance applicable to taconite facilities in Minnesota, as summarized in Table 9-6.

Table 9-6
Minnesota Standards for Stationary Sources Relevant to Standards of Performance at Taconite Plants

Chapter/Part No.	Part Description	Potentially Affected Taconite Emission Unit Category
7011.0150	Preventing Particulate Matter from Becoming Airborne	Fugitive Particulate Sources
7011.0610	Standards of Performance for Fossil Fuel-Burning Direct Heating Equipment	Induration Sources
7011.0710	Standards of Performance for Pre-1969 Industrial Process Equipment	Particulate Point Sources Induration Sources (pre-July 9, 1969)
7011.0715	Standards of Performance for Post-1969 Industrial Process Equipment	Particulate Point Sources Induration Sources (post-July 9, 1969)
7011.1150	Standards of Performance for New Coal Preparation Plants	Fugitive Particulate Sources Particulate Point Sources
7011.2700	Standards of Performance for New Metallic Mineral Processing Plants	Fugitive Particulate Sources Particulate Point Sources

These relevant parts of chapter 7011 of the Minnesota rules are summarized below. See Attachment N for full text of these rules.

9.4.1 Minn. R. 7011.0150 – Preventing Particulate Matter from Becoming Airborne

This part prohibits the handling, use, transporting, or storage of any material in a manner which may allow avoidable amounts of particulate matter to become airborne.

9.4.2 Standards of Performance for Fossil Fuel-Burning Direct Heating Equipment

Minn. R. 7011.0610 prohibits direct heating equipment to discharge any gases which: contain particulate matter in excess of the limits allowed by parts 7011.0700 to 7011.0735; or exhibit greater than 20% opacity; or contain sulfur dioxide in excess of 4 lb/MMBtu if a solid fossil fuel is burned or 2 lb/MMBtu if a liquid fossil fuel is burned, if the total rated heat input of all indirect and direct heating equipment of the owner or operator at that particular location exceeds 250 MMBtu/hr and the direct heating equipment is located outside the Minneapolis-Saint Paul Air Quality Control Region. This rule applies to induration sources at the taconite plants.

9.4.3 Standards of Performance for Pre-1969 Industrial Process Equipment

Minn. R. 7011.0710 prohibits industrial process equipment which was in operation before July 9, 1969 to discharge any gases which: in any one hour contain particulate matter in excess of the amount in part 7011.0730 for the allocated process weight, provided that the facility is not required to reduce the particulate matter emission below the concentration permitted in part 7011.0735 for the appropriate source gas volume or that regardless of the mass emission permitted by part 7011.0730 the facility is not permitted to emit particulate matter in a concentration in excess of 0.30 gr/scf of exhaust gas; or exhibit greater than 20% opacity. Such a facility located outside the Minneapolis-Saint Paul Air Quality Control Region and the city of Duluth which has control equipment with a collection efficiency of not less than 85% by weight and does not cause a violation of the ambient air quality standards is considered in compliance with the requirements above.

9.4.4 Standards of Performance for Post-1969 Industrial Process Equipment

Minn. R. 7011.0715 prohibits industrial process equipment which was in operation after July 9, 1969 to discharge any gases which: in any one hour contain particulate matter in excess of the amount in part 7011.0730 for the allocated process weight, provided that the facility is not required to reduce the particulate matter emission below the concentration permitted in part 7011.0735 for the appropriate source gas volume or that regardless of the mass emission permitted by part 7011.0730 the facility is not permitted to emit particulate matter in a concentration in excess of 0.30 gr/scf of exhaust gas; or exhibit greater than 20% opacity. Such a facility located outside the Minneapolis-Saint Paul Air Quality Control Region and the city of Duluth which has control equipment with a collection efficiency of not less than 85% by weight and does not cause a violation of the ambient air quality standards is considered in compliance with the requirements above.

9.4.5 Standards of Performance for New Coal Preparation Plants

Minn. R. 7011.1150 incorporates 40 CFR part 60 subpart Y, Standards of Performance for Coal Preparation Plants, by reference (summarized in Section 9.2).

9.4.6 Standards of Performance for New Metallic Mineral Processing Plants

Minn. R. 7011.2700 incorporates 40 CFR part 60 subpart LL, Standards of Performance for Metallic Mineral Processing Plants, by reference (summarized in Section 9.1).

9.5 *Michigan Air Pollution Control Rules*

Michigan Department of Environmental Quality (MDEQ) air pollution control (APC) rules were reviewed for relevance to the emission limits at two taconite ore processing facilities located in the state. It was determined that four parts apply to taconite facilities for purposes of BART, as shown in Table 9-7.

Table 9-7
MDEQ APC Rules Relevant to Standards of Performance at Taconite Plants

Part No.	Part Description	Potentially Affected Taconite Emission Unit Category
3	Emission Limitations And Prohibitions - Particulate Matter	Fugitive Particulate Sources Point Particulate Sources Induration Sources
4	Emission Limitations And Prohibitions - Sulfur-Bearing Compounds	Induration Sources
7	Emission Limitations And Prohibitions - New Sources Of Volatile Organic Compound Emissions	Induration Sources
8	Emission Limitations And Prohibitions - Oxides Of Nitrogen	Induration Sources

These four relevant parts of the Michigan rules are summarized below. See Attachment O for full text of these rules.

9.5.1 Part 3 – Particulate Matter Emission Limitations and Prohibitions

9.5.1.1 R 336.1301 – Standards for density of emissions

This rule prohibits process equipment from exceeding an opacity greater than the most stringent of the following: (a) a 6-minute average of 20%, (b) a limit specified by an applicable federal new source performance standard, (c) a limit specified as a condition of a permit to install or operate.

9.5.1.2 R 336.1331 – Emission of particulate matter

This rule identifies maximum allowable emission rates of PM from process equipment. It includes rates for grate kilns and traveling grates as shown in Table 9-8.

Table 9-8
Maximum Allowable PM Emission Rates for Grate Kilns and Traveling Grates

Process or process equipment	Gas flow rate (SCFM)	Maximum allowable emission at operating conditions[1] (lbs. Particulate/1,000 lbs. gas)	Applicable reference test method
<u>Iron ore pelletizing</u>	Over 600,000	Apply to department for specific emission limit.	
Grate kilns and traveling grates	300,000-600,000	0.10	5B or 5C
	100,000-300,000	0.15	5B or 5C
	0-100,000	0.20	5B or 5C

The rule also identifies the allowable PM emission rate from process equipment based on process weight rate.

9.5.1.3 R 336.1370 – Collected air contaminants

This rule requires that air contaminants be removed as necessary to maintain the equipment at the required operating efficiency. This rule also specifies material handling methods required for transporting air contaminants.

9.5.1.4 R 336.1371 – Fugitive dust control programs other than areas listed in table 36

This rule requires a facility that processes, uses, stores, transports, or conveys bulk materials, such as metal ores, from air pollution control devices to submit a fugitive dust control program. The rule contains the fugitive dust control program requirements.

9.5.1.5 R 336.1372 – Fugitive dust control program; required activities; typical control methods

This rule identifies the provisions that apply to the loading or unloading of open storage piles of bulk materials, transporting of bulk materials, outdoor conveying, roads and lots, inactive storage piles, and building ventilation as a source of fugitive dust.

9.5.2 Part 4 – Sulfur-Bearing Compounds Emission Limitations and Prohibitions

9.5.2.1 R 336.1402 - Emission of sulfur dioxide from fuel-burning sources other than power plants

This rule prohibits the emission of sulfur dioxide from the combustion of any coal or oil fuel in excess of 1.7 lb/MMBtu for oil fuel or in excess of 2.4 lb/MMBtu for coal fuel.

9.5.3 Part 7 – New Sources of VOC Emissions – Limitations and Prohibitions

9.5.3.1 R 336.1702 – New sources of volatile organic compound emissions generally

This rule prohibits the emission of volatile organic compounds from any new source in excess of the lowest maximum allowable emission rate of the following:

a. The maximum allowable emission rate listed by the department on its own initiative or based upon the application of the BACT.
b. The maximum allowable emission rate specified by a federal new source performance standard.
c. The maximum allowable emission rate specified in a permit.

9.5.4 Part 8 – Emission Limitations and Prohibitions - Oxides of Nitrogen

9.5.4.1 R 336.1801 – Emission of oxides of nitrogen from non-SIP call stationary sources

This rule requires fossil fuel-fired emission units with a PTE of more than 25 tons of NOx for each ozone control period that is greater than 250 MMBtu/hr to submit a proposal for NOx control. It contains the proposal requirements and means by which NOx emissions must be measured. The rule also allows an affected source to participate in Michigan's emission trading program.

9.6 *Summary of Canadian Provincial Air Pollution Control Regulations*

Taconite plants are located in three Canadian provinces, Newfoundland, Ontario, and Quebec,[25] so only the air pollution control regulations in these three provinces have been reviewed. The relevant Canadian provincial rule parts are summarized below. See Attachment P for full text of these rules.

9.6.1 Newfoundland Air Pollution Control Regulations

The standards of performance in the Newfoundland air pollution control regulations that are potentially applicable to taconite plants include an air contaminant standard for any point source and a visible emissions standard.[26]

9.6.1.1 Stationary source of air contamination

The maximum concentration of a contaminant at a point of impingement from a source must not be greater than the concentration described in Table 9-9.

[25] Canadian Minerals Yearbook, 1995; chapter 32, "Iron Ore and Primary Iron."
[26] Based on "Consolidated Newfoundland Regulation 957/96" found at http://www.gov.nf.ca/hoa/sr/, as of April 2003.

Table 9-9
Maximum Concentration of a Contaminant at a Point of Impingement

Contaminant	1 hour averaging period
SO_2	680 ug/m^3
NOx	400 ug/m^3
PM	80 ug/m^3
Ammonia	3,000 ug/m^3
Ozone	160 ug/m^3
Dustfall	7,000 ug/m^2

9.6.1.2 Visible emission standards

Opacity must not exceed density No. 1 on the visible emission chart, except:

a. For a period of not more than 4 minutes in the aggregate in a half hour period, visible emission may have an opacity exceeding density No. 1 but not exceeding density No. 2;
b. Where a new fire is started in combustion process equipment, the visible emission may have an opacity not exceeding density No. 3 for a period not more than 3 minutes in the aggregate in a quarter hour period up to one hour after the new fire is started.

The visible emission chart is based on the Ringelmann scale for determining opacity.[27]

9.6.1.3 Recording devices

The minister may require the installation of devices or methods that are necessary to:

a. Record the periods of operation of process, combustion or control equipment, the records from which shall be available to a department official.
b. Measure and record concentrations of air contaminants at their source and points of impingement, the records and measurements from which shall be available to a department official.

9.6.2 Ontario Air Pollution Control Regulations

The standards of performance in the Ontario air pollution control regulations that are potentially applicable to taconite plants include an air contaminant standard for any point source and a visible emissions standard.[28]

[27] See Schedule C of c. Q-2, r. 20, Regulation respecting the quality of the atmosphere, found at www.publicationsduquebec.gouv.qc.ca/home.php, as of April 2003.
[28] Based on "Environmental Protection Act, R.S.O. 1990, c. E.19" found at http://www.e-laws.gov.on.ca/, as of April 2003.

9.6.2.1 Control of air contaminants

The maximum concentration of a contaminant at a point of impingement from a source must not be greater than the concentration described in Table 9-10 below:

Table 9-10
Maximum Concentration of a Contaminant at a Point of Impingement

Contaminant	½ hour averaging period
SO_2	830 ug/m^3
NOx	500 ug/m^3
PM	100 ug/m^3
Ammonia	3,600 ug/m^3
Ozone	200 ug/m^3
Dustfall	8,000 ug/m^2

Visible emissions must not have shades of grey darker than No. 1 on the Visible Emission Chart of the Province of Ontario or obstruct the passage of light to a degree greater than 20% at the point of emission. A visible emission from a source of combustion using solid fuel for a period of not more than four minutes in the aggregate in any 30-minute period may be in shades of grey darker than No. 1, but not darker than No. 2 on the Visible Emission Chart or obstruct the passage of light to a degree greater than 20% but no greater than 40% at the point of emission.

A facility must not construct, alter, demolish, drill, blast, crush or screen anything so that a contaminant is carried beyond the limits of the property on which the operation is being carried out or sandblast anything so that a contaminant is emitted into the air to an extent or degree greater than that which would result if every step necessary to control the emission of the contaminant were implemented.

9.6.3 Quebec Air Pollution Control Regulations

The standards of performance in the Quebec air pollution control regulations[29] that are potentially applicable to taconite plants include:

- a visible emissions standard,
- a VOC standard,
- a fugitive emissions standard,
- a particulate matter standard,
- a fossil fuel use standard, and

[29] Based on "Regulation respecting the quality of the atmosphere, c. Q-2, r. 20" found at http://www.publicationsduquebec.gouv.qc.ca/.

- an iron ore pelletizing plant PM standard.

9.6.3.1 Opacity of emissions

The concentration of contaminants discharged by a stationary source must not exceed 20% opacity. This does not apply to the starting of a fire or the soot blowing. The degree of opacity may then, for a maximum period of 4 consecutive minutes exceed 20% but never be equal to or higher than 60% opacity. During the operation of a stationary source, the degree of opacity of an emission may also exceed 20% for one or several periods not exceeding 4 minutes in any one hour, but never be equal to or higher than 40%.

9.6.3.2 Emission of organic compounds

A facility may not emit into the atmosphere:

a. more than 15 kilograms per day and 3 kilograms per hour of organic compounds for photochemically reactive organic compounds which are not submitted to a baking process or do not come in contact with a flame;
b. more than 1,400 kilograms per day or 200 kilograms per hour of organic compounds where non-photochemically reactive solvents are not submitted to a baking process or do not come in contact with a flame.

For the purposes of enforcing this section, the different portions of a continuing process constitute only one stationary source. Organic compound emissions mentioned in (b) and (c) comprise all emissions produced during the 12 hours used for drying, following the last application of organic solvents or substances which contain them.

Organic compound emissions may exceed the standards above provided that there is a reduction of the emissions in the atmosphere of at least 90% for incineration of organic compounds and at least 85 % in other cases.

9.6.3.3 Fugitive emissions

A facility which wrecks, builds, repairs or maintains a building or a thoroughfare must spread water or another dust control product to prevent the raising of dust in all cases where the carrying out of such activity brings about the emission of dust. A facility that produces dust emissions from access lanes and road ways located on the same property as a stationary source or a pile of aggregates, materials, mine refuse, ore, ore concentrate or pellets must take the necessary measures to control these emissions so as to eliminate those effects. This section also applies to the transport by conveyor belt, truck, or railway car of the materials mentioned above.

In the case where the transfer or free fall of materials of any kind including aggregates, mine rejects ore, ore concentrate or pellets, brings about the emission of dust which can be seen in the atmosphere more than 2 meters away from the emission source, the facility must take the necessary measures so that:

a. The stationary transfer point is included in an enclosed space equipped with ducts which draw dust to a dust collector so that the PM emissions are not greater than 50 mg/m^3; or
b. The free fall height of these materials does not exceed 2 meters.

Dust emissions resulting from dry sandblasting operations must be controlled by using an enclosure or screen in order to confine the dust inside the spaces thus enclosed or closed. This section also applies to wet-type sandblasting operations when there are dust emissions that can be seen in the atmosphere more than 2 meters from the emission source.

Dust recuperated by a dry collector must be handled and transported so that there is no dust released which can be seen 2 meters from the emission source. When it is not recycled, it must be stored, spread or disposed of on the ground and the necessary measures must be taken to prevent any release of dust which can be seen 2 meters away from the emission source, and in order to prevent water contamination.

9.6.3.4 Particulate matter general emission standards

A facility must not emit PM in excess of the hourly quantities allowed respectively for existing and new stationary sources in Schedules A and B of the standard. PM emissions from any transfer of bulk material except wood, any storage in confined environment, any digging other than the sinking of a supply water well, any welding operation metal works in indoor sandblasting, and any process for the preparation, concentration, agglomeration or drying of ore or ore concentrate, as well as to the related handling operations done in a plant for the preparation, concentration, agglomeration or drying of metallic ores, must not exceed 50 mg/m^3.

9.6.3.5 Use of fossil fuels

Fossil fuel burning equipment must not emit PM beyond the standards described in Table 9-11 below:

Table 9-11
PM Emission Limits for Fossil Fuel Burning Equipment

Heat Input Capacity of fuel as fired	Type of fuel	New Installation (mg/MJ)	Existing Installation (as of 6/1/81) (mg/MJ)
3 – 15 MW	gas or oil product	60	85
3 and 70 MW	coal	60	85
>15 MW	gas or oil product	45	60
>70 MW	coal	45	60

A new fuel burning equipment must not emit NOx beyond the standards described in Table 9-12 below:

Table 9-12
NOx Emission Limits for New Fuel Burning Equipment

Heat Input Capacity of fuel as fired	Type of fuel	Emission Standard (ppm, dry basis to 3% O2)
>70 MW	coal	500
	oil	250
	gas	200
15-70 MW	coal	450
	oil	325
	gas	150

A facility must not burn fuel with a sulfur content higher than:

a. 2.0 % in weight for heavy oil;
b. 1.0 % in weight for intermediate oil;
c. 0.5 % in weight for light oil; and
d. 2.0 % in weight for coal.

The standards above for heavy oil and coal do not apply in cases where:

a. a portion of the sulfur contained in the flue gases is recovered and combined to a raw material coming in contact with these gases;
b. a portion of the sulfur contained in the flue gases is retained by a gas cleaning equipment; or
c. another fossil fuel with a low sulfur content is used simultaneously in an oil refinery.

Except as provided in the paragraph above, the quantity of SO_2 emitted by burning any fossil fuel must not exceed that emitted by burning a quantity equivalent in heating value of heavy oil whose sulfur content does not exceed the standards described above.

The exhaust speed of flue gases from a new fuel burning equipment fired with heavy oil or coal must be at least 15 meters per second at the outlet of a new stack when the equipment operates at nominal capacity.

The minimum height of any new stack of a fuel burning equipment using heavy oil or coal must be equal at least to the one computed in conformity with the method entitled *Méthode de calcul de la hauteur minimale des cheminées* published in 1979 by the Services de protection de l'environnement. The height of an existing stack cannot be reduced unless it still is, after reduction, in conformity with the height computed according to the method provided for above.

9.6.3.6 Iron ore pelletizing plants

The indurating process of an iron ore pelletizing plant must not emit PM in excess of that described in Table 9-13 below:

Table 9-13
PM Emission Limits for Induration Processes at an Iron Ore Pelletizing Plant

Type of Plant	Standard
New plant of any capacity	0.10 kg/tonne of pellets produced*
Existing plant with a nominal yearly production lower than 1,500,000 tons of iron oxide pellets	0.36 kg/tonne of pellets produced*
Existing plant with a nominal yearly capacity equal to or greater than 1,500,000 tons of iron oxide pellets	0.12 kg/tonne of pellets produced*

* Including the recirculating load, if applicable.

9.7 *Summary of BACT Determinations*

The information provided in this section is based on two BACT determinations found in EPA's RACT, BACT, LAER Clearinghouse (RBLC) and the Title V operating permits of the taconite facilities. The RBLC was queried on April 15, 2003 by taconite facility name.

One taconite processing facility determined that its indurating machine is subject to a BACT limit for NOx. Eleven control options were examined and BACT determined to be limiting fuel use to 270 MMBtu/hr for all the burners combined in addition to the use of existing low-NOx burners. NOx is limited to 1088 lb/hr. See Attachment Q for a summary of the RBLC report. The operating permit for this facility was issued January 14, 2000.

The MPCA determined for another taconite processing facility that selective catalytic reduction (SCR) is not BACT for NOx emission control for its PSD permit.

10 Visibility Impacts Screening Evaluation of the Taconite Industry

Barr has performed a visibility impacts screening evaluation for the purpose of understanding the pollutants of concern for visibility from the taconite industry as well as to inform the taconite industry on visibility impacts from its emission sources.

The results of this modeling analysis serve to assess the potential change in visibility due to the application of BART at the taconite facilities in Minnesota. Due to the simplifying assumptions and streamlined analysis, the visibility impacts screening evaluation, in itself, has limited application. As such, the results in Section 10.2 are shown for informational purposes and should not be construed to represent a determination of compliance with an applicable requirement.

10.1 *Modeling Protocol*

On August 25, 2003, Barr submitted a memorandum to Ms. Margaret McCourtney and Mr. Stuart Arkley at MPCA outlining a protocol to use for the visibility impacts screening evaluation. A copy of this memo is in Attachment S. Pursuant to this memorandum and subsequent e-mail correspondence between Barr and MPCA, the following model protocol is used for the visibility impacts screening evaluation.

10.1.1 Modeling Program

The CALMET/CALPUFF/CALPOST system will be used for this analysis. Attachments T, U, and V contain an input file an example CALPUFF input file with the proposed control options to be used in the analysis. This modeling program is chosen for the following reasons: 1) CALPUFF is an EPA-approved model for performing far-field visibility impacts studies at Class I areas, and 2) Barr had recently performed a visibility impacts analysis for a potential new taconite plant in northern Minnesota. Mr. John Notar of the National Park Service approved in general the CALPUFF and CALMET input files before the project was subsequently cancelled. These files were used as templates for the modeling analysis.

Four CALMET input files were created, one for each quarter in the 12-month period between December 1, 1984, and November 30, 1985. Six CALPUFF and CALPOST input files were created. The CALPUFF executable used for this analysis allows 500 receptors, so three runs for needed to capture all 1,313 receptors (see Section 10.1.4) for the pre-BART and post-BART emissions scenarios.

Note that regulatory agencies will likely not use the CALMET/CALPUFF/CALPOST system for regional haze modeling. The visibility impact results from other modeling programs may reveal conclusions different than those gathered in this analysis using CALMET/CALPUFF/CALPOST.

10.1.2 Sources

Consistent with Table 7-1, four 'typical' sources will be modeled: grate/kiln furnace, straight grate furnace, pellet cooler, and ore handling. One representative stack will be used for each of the sources, for a total of four modeled sources. Table 10-1 contains the stack parameters that will be used in the modeling. Flow rate and temperature parameters were taken from Table 7-1. The stack height and stack diameter parameters are estimated from taconite source data in the MPCA Delta Database. All of the stack parameters represent a typical stack configuration rather than a "worst-case" stack.

The model plant location containing the four sources as well as the location of the existing Minnesota taconite plants are shown in Figure 10-1.

Table 10-1
Sources and Stack Parameter Data in CALPUFF Input File

	English Units			
	Height (ft)	Temperature (F)	Flow (acfm)	Diameter (ft)
Straight Grate Furnace	140	135	188,865	8
Grate/Kiln Furnace	140	135	377,730	13
Pellet Cooler	135	800	239,425	13
Ore Handling	80	77	7,143	2

	Metric Units			
Source Type	Height (m)	Temperature (K)	Velocity (m/s)	Diameter (m)
Straight Grate Furnace	42.7	330	19	2.4
Grate/Kiln Furnace	42.7	330	14	4.0
Pellet Cooler	41.1	700	9	4.0
Ore Handling	24.4	298	12	0.6

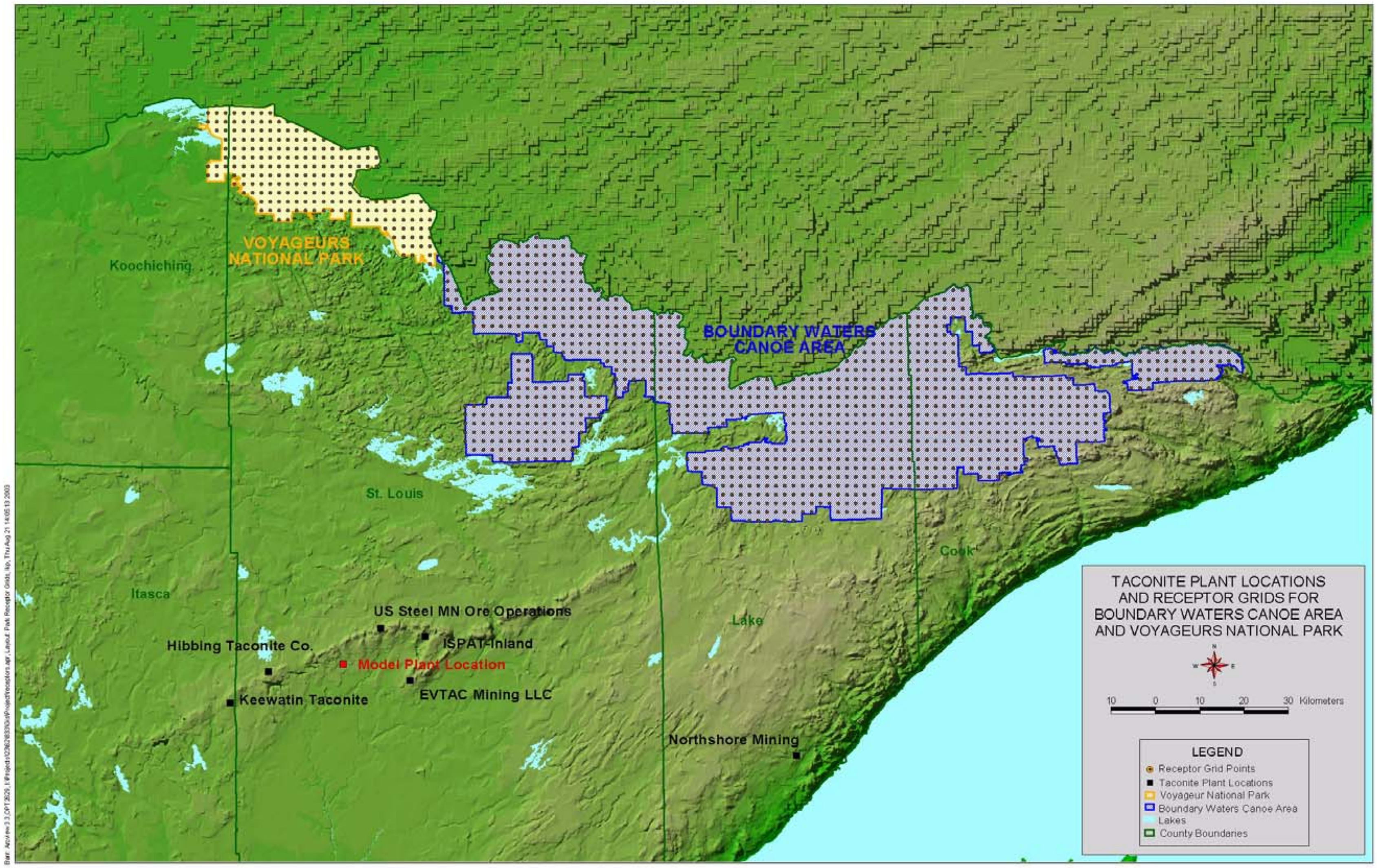
Barr has not modeled fugitive particulate sources for the following reasons:

- Only one facility included fugitive sources in the BART-eligible survey, indicating that most fugitive sources are either not BART-eligible or were specifically excluded in the survey.

- Fugitive emissions tend to be coarse particulates, which in general are not the drivers for far-field visibility degradation as compared to sulfates, nitrates, and fine particulate matter.

- All of the taconite facilities have fugitive dust control plans, as described in the draft BART report; therefore, BART for fugitive sources would likely not be different from what is already in the fugitive dust control plans.

Figure 10-1. Location of Modeled Plant and Class I Area Receptors.



10.1.3 Pollutants and Emission Rates

CALPUFF allows for the specification of the pollutants to be modeled. Because limited information is currently available on the pollutants to be modeled, especially with respect to fine particulate matter (e.g., $PM_{2.5}$) and elemental carbon, we propose to model the emissions of SO_2, NOx, and coarse particulate matter (PM_{10}), and model the ground-level concentrations of these three pollutants plus the formation of nitrates (NO_3 and HNO_3) and sulfates (SO_4).

For estimated pre-BART emissions from each of the four sources, taconite industry total emissions are based on the 2001 emission inventory total in Table 5-1 and divided by a 0.85 capacity factor, as referenced in a technical paper from Mr. Hongming Jiang of MPCA regarding the taconite industry. The scaled-up 2001 industry emission totals are apportioned into the four sources as shown in Table 10-2, which reflect emissions from the source categories. One pre-BART scenario is modeled.

The post-BART emission rates are equal to the pre-BART emission rates times an estimated control efficiency for the selected BART. Some of the BART-eligible sources already have controls that would likely meet BART, so the incremental control efficiency dictated by BART for the taconite industry will likely be less than that shown for the individual control technologies in Table 6-1 of the draft BART report. Barr proposes a 30% emissions reduction in pre-BART NOx, SO2, and PM10 emission rates for the post-BART scenario. This is an estimate that will help provide an idea of the visibility reduction in relationship to an emissions reduction. It should not be construed to be an expected emissions reduction from the taconite industry due to application of BART.

Table 10-2
Pre-BART and Post-BART Taconite Industry Emission Rates in CALPUFF Input File

	Pre-BART Emissions (tons)			Post-BART Emissions (tons)		
Source	**PM_{10}**	**SO_2**	**NOx**	**PM_{10}**	**SO_2**	**NOx**
Grate/Kiln	4,595	6,693	21,395	3,217	4,685	14,977
Straight Grate	358	331	4,396	251	232	3,077
Pellet Cooler	195	--	--	137	--	--
Ore Handling	1,027	--	--	719	--	--

10.1.4 Receptors

Discrete receptors are established every 2 kilometers at both Boundary Waters Canoe Area Wilderness (BWCAW) and Voyageurs National Park. There are 1,105 receptors for BWCAW and 208 receptors for Voyageurs National Park. See Figure 10-1 for identification of the receptor locations.

10.1.5 Model Control Selections

The model source location of the single plant to be modeled is illustrated as a figure in Attachment C. The base elevation for the modeled plant is 475 m, which is the average of the five plants on the Mesabi range. Building downwash will not be included in the model. Barr modeled one year of meteorological data (December 1984 through November 1985). Deposition is included in the modeling. Other non-taconite industry sources are not included in the modeling in order to gauge the impact of pre-BART to post-BART emissions on visibility. Default CALPUFF values for the chemistry parameters are used with the following exceptions that were approved in a previous analysis by National Park Service:

Ozone Background:	40 ppm	(default is 80)
Ammonia Background:	1 ppm	(default is 10)

10.2 *Modeling Results*

Table 10-3 summarizes the comparison in visibility impacts between pre-BART and post-BART taconite industry emissions. The results in this table reflect the highest percent change in light extinction at any of the 1,313 receptors modeled. Figure 10-2 illustrates the day-to-day variation in the modeled visibility impact from the taconite industry. In summary, the visibility impacts screening evaluation of taconite industry pre-BART and post-BART emissions make known the following:

1. On average, nitrates formed from taconite industry NOx emissions represent approximately 85 % of the visibility impact at Class I areas, whereas sulfates constitute 9 % and particulate matter makes up 6 % of the visibility impact. For comparison purposes, a study on visibility impairment by Colorado State University (see Section 7.1.1) found that sulfates contribute 54 % of the visibility impairment and nitrates contribute 17 % of the visibility impairment in the Voyageurs National Park and BWCAW.

2. As noted in Section 10.1.3, fine particulate matter and elemental carbon emissions have not been estimated for this modeling analysis due to the lack of emissions data. In general, fine particulate matter and elemental carbon cause significantly higher visibility impacts than coarse particulate matter.

3. Although nitrates contribute the vast majority of the visibility impact, sulfates and coarse particulate matter can each cause a noticeable (i.e., greater than 5 %) increase in light extinction on certain days as well.

4. The reduction in visibility impact at the highest receptor on the worst-case day closely matches the emissions reduction of 30 % for each pollutant (SO_2, NOx, and PM_{10}).

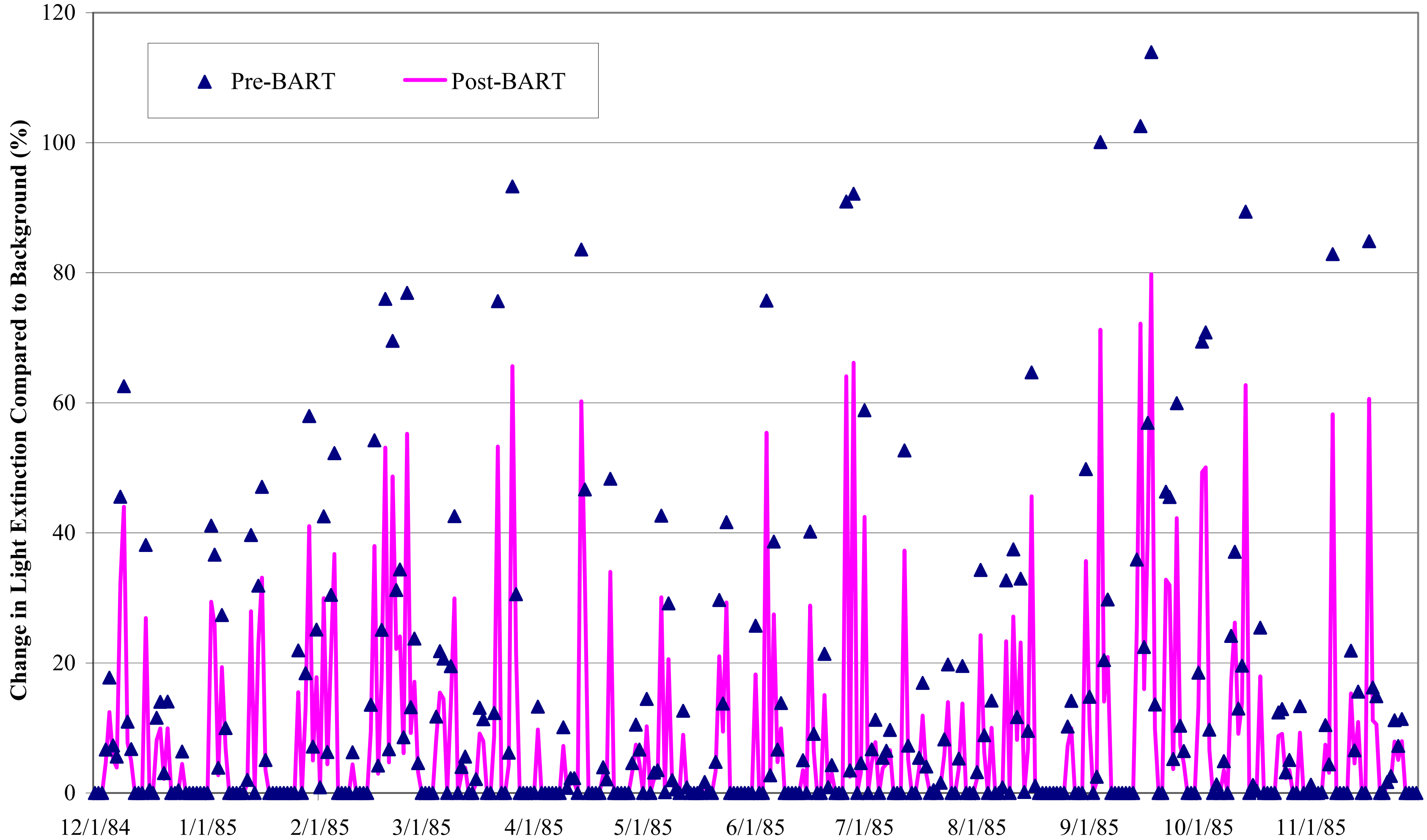
5. Relative humidity plays an important role in visibility degradation. The higher the relative humidity, the greater the visibility impact. However, in Figure 10-1 there seems to be no significant seasonal trends.

Table 10-3
Comparison of Modeling Results Between Pre-BART and Post-BART Taconite Industry Emissions

Estimated Potential Emissions Scenario	Highest Daily % Change in Light Extinction*	Number of Days/Year with Greater than 0%, 5%, and 10% Light Extinction Change*			Average Contribution by Pollutant for those Days With > 5% Change in Light Extinction*		
		> 0% Change	> 5% Change	> 10% Change	Sulfates (SO_4)	Nitrates (NO_3)	Coarse Particulate Matter (PM)
Pre-BART	114%	200 Days	148 Days	115 Days	9.4%	84.4%	6.1%
Post-BART (30% less than Pre-BART)	80%	199 Days	125 Days	85 Days	8.9%	85.1%	6.0%
% Difference between Pre- and Post-BART	-30%	-1%	-16%	-26%	-5%	+1%	-2%

* The percent change in light extinction is calculated as the difference in light extinction due to the modeled sources and modeled natural background.

Figure 10-2. Daily Change in Light Extinction from Pre-BART and Post-BART Taconite Industry Emissions



11 Conclusions

The 1999 Regional Haze final rule and 2001 proposed BART guidelines lay a regulatory framework for states and the regulated community to begin the process of meeting the visibility goals in Section 169a of the CAA. However, legal challenges to the BART guidelines and the $PM_{2.5}$ national ambient air quality standards (NAAQS) have delayed implementation of the program.

Minnesota, like all states, is required to submit an implementation plan for Regional Haze. In addition to the progress goals and visibility improvement strategies that are required in the implementation plan, the MPCA must identify specific BART limitations for units that are subject. Based on a survey of BART-eligible units conducted by the MPCA, all six taconite plants in Minnesota have BART-eligible units.

Utilizing the results from MPCA's BART-eligible unit survey for the taconite plants, Barr has classified taconite emission units into three categories: fugitive particulate sources, point particulate sources, and induration point sources. The taconite BART screening evaluation focuses on control technology options for these three emission unit categories.

A comprehensive review of Federal, State (Minnesota and Michigan), and Canadian (Newfoundland, Ontario, and Quebec) air quality regulations revealed that the three taconite emission unit categories are already required to meet existing standards of performance, whether these standards are generally applicable state requirements or more stringent emission limitations. It should be noted that both Michigan and Quebec have particulate matter emission limitations in their regulations that are specific to existing taconite induration furnaces.

The final NESHAPs for taconite iron ore processing establishes stringent particulate matter controls on the induration point sources as well as most of the fugitive and point particulate sources. The particulate matter limits for existing sources would very likely satisfy BART, since these limits are based on the average emission limitation achieved by the best performing five sources, as required in Section 112(d)(3)(B) of the CAA. Since a BART evaluation must take into account the level of control already in place, the cost effectiveness of installing BART – on top of the existing NESHAPs (or BACT, LAER, or NSPS) levels of control – may be restrictively high because baseline annual particulate matter emissions will be very low due to the aforementioned existing controls. Uncontrolled emission units that are subject to BART but are not already controlled for a visibility impairing pollutant will most likely require a level of investment in order to meet BART.

The anticipated first compliance date for a BART limitation at taconite facilities is December 2012. Several variables influence the timing, such as the $PM_{2.5}$ attainment/nonattainment designation time frame, MPCA's Regional Haze implementation plan schedule, and the compliance schedule for taconite facilities to meet BART after the implementation plan is approved.

In addition to providing the regulatory context for this analysis, another purpose of this report is to conduct a BART screening evaluation for the taconite industry. The approach addresses the taconite industry in general; site-specific BART analyses are beyond the scope of this analysis. This analysis contains information, cost calculations, and model examples that provide for a uniform approach in subsequent preparation of site-specific BART analyses.

Four model sources were chosen and evaluated for the technical feasibility of air pollution controls on a pollutant-by-pollutant basis. Several possible control technologies are determined to be technically infeasible on an industry-wide basis because of conditions inherent to the taconite manufacturing process. The remaining technically feasible options are summarized in Table 11-1.

When site-specific BART analyses are performed, some of the options determined to be feasible for the general industry may be found technically infeasible based on site-specific conditions. The approach for calculating the cost of controls is demonstrated for the particular model source.

The affordability of BART must be analyzed on a site-specific basis. Given the current economics of the industry, a significant cost burden associated with BART could impact the future viability of the industry.

Table 11-1
Summary of Technically Feasible Control Technologies

Model Source Category	Pollutant	Control Technology	Control Efficiency
Induration	NOx	SCR	70% to 90%
		IFGR Burners	50%
		Low-NOx Burners	25%
		Ported Kiln	$\geq$ 5%
	SO_2	High Efficiency Wet Scrubber	95%
		Low Efficiency Wet Scrubber	80%
		WWESP	80%
	PM	Dry ESP	98%-99%+
		WWESP	98%-99%+
		High Efficiency Wet Scrubber	95%-99%+
		Low Efficiency Wet Scrubber	90%-95%
		Multiclones	50%-80%
Pellet Coolers	PM	Fabric Filters (Baghouses)	98%-99%+
		Dry ESP	98%-99%+
		WWESP	98%-99%+
		High Efficiency Wet Scrubber	95%-99%+
		Low Efficiency Wet Scrubber	90%-95%
		Multiclones	80%-90%
Material Handling	PM	Fabric Filters (Baghouses)	98%-99%+
		Dry ESP	98%-99%+
		WWESP	98%-99%+
		Wet Scrubbers High Efficiency	95%-99%+
		Wet Scrubbers Low Efficiency	90%-95%
		Multiclones	80%-90%
		Enclosure	50%-100%
		Chemical Stabilization	75%-80%
		Wet Suppression	50%-75%
		Best Management Practices	Variable

ATTACHMENT A

December 9, 2002, State Register

Minnesota Historical Society

Request for Bids for Stabilization and Repair of Meighen Residence Frame Addition at Historic Forestville Preston, Minnesota

The Minnesota Historical Society seeks bids for stabilization and repair work on the Meighen Residence Frame Addition at Historic Forestville in Preston, Minnesota. Work includes sill replacement; joist repair/replacement; excavation of crawlspace; foundation stabilization; restoration of siding to original pattern; restoration/repair of wood frame and sash windows; repair/restoration/replacement of wooden storm windows; sanding/priming/painting exterior; re-installation of existing wood tongue and groove flooring; lathe and plaster repair; draining and filling cistern; and realignment/installation of gutter system. Also included are miscellaneous repairs on attached brick structures including painting windows and tuck-pointing. All work must conform to the Secretary of the Interior's Standards for Historic Preservation.

A **MANDATORY** pre-bid meeting will be held Wednesday, December 18, 2002, at 11:00 a.m. at Historic Forestville. Copies of the bidding documents may be obtained from Collaborative Design Group, inc., 1501 Washington Avenue South, Suite 300, Minneapolis, Minnesota, 55454.

The deadline for receipt of bids is **Tuesday, January 7, 2003, 2:00 p.m. Late bids will not be accepted.** Bids should be sent or delivered to: Chris M. Bonnell, Contracting Officer, Minnesota Historical Society, 345 Kellogg Boulevard West, St. Paul, Minnesota 55102. Clearly mark the project name "Meighen Residence Frame Addition, Historic Forestville" on the outside of the package.

Dated: 9 December 2002

Minnesota Pollution Control Agency

Notice of Availability of Contract for Assessment of Impact of Regional Haze Rules on the Taconite Industry

The Minnesota Pollution Control Agency (MPCA) is requesting proposals for the purpose of surveying and reporting on the potential impacts of the federal regional haze rule on the taconite industry in Minnesota. This rule requires certain sources to conduct an initial analysis which may lead to a more detailed assessment and installation of emissions controls that conform to Best Available Retrofit Technology (BART) requirements. The taconite industry has been identified by the MPCA as one of the industries for which a BART analysis is required. This project will provide a general analysis for the industry as a whole that can be used by both the MPCA and the taconite industry itself as a basis for planning purposes and for any facility-specific detailed assessments that will follow.

Work is proposed to start after February 1, 2003.

Call or write for a copy of the full Request for Proposal document, which will be sent free of charge to interested vendors. The full Request for Proposal can be obtained from:

Stuart Arkley, Project Manager
Policy and Planning Division
Minnesota Pollution Control Agency
520 Lafayette Road
St. Paul, MN 55155-4194
Email: *stuart.arkley@pca.state.mn.us*
Phone: (651) 296-7774
Fax: (651) 296-8676

Proposals submitted in response to the Request for Proposals in this advertisement must be received at the address above no later than **2:30 p.m. Central Time on January 6, 2003. Late proposals will not be considered.**

This request does not obligate the state to complete the work contemplated in this notice. The state reserves the right to cancel this solicitation. All expenses incurred in responding to this notice are solely the responsibility of the responder.

ATTACHMENT B

MPCA Request for Proposal

REQUEST FOR PROPOSALS

Minnesota Pollution Control Agency

Project Overview

The Minnesota Pollution Control Agency (MPCA) requests proposals to survey and report on the potential impacts of the federal regional haze rule on the taconite industry in Minnesota. This rule requires certain sources to conduct an initial analysis that may lead to a more detailed assessment and installation of emissions controls that conform to Best Available Retrofit Technology (BART) requirements. The taconite industry has been identified by the MPCA as one of the industries for which a BART analysis is required. This project will provide a general analysis for the industry as a whole that can be used by both the MPCA and the taconite industry itself as a basis for planning purposes and for any facility-specific detailed assessments that will follow.

MPCA staff met with representatives of the six Minnesota taconite plants on October 3, 2002, to explain the scope of the proposed project and to determine the level of interest from the industry. The industry representatives expressed support and requested the option to review work products at key stages of the project.

The U.S. Environmental Protection Agency (EPA) issued BART determination guidelines on July 20, 2001, that will serve as a framework for this project. However, because some of these guidelines are still subject to legal challenge and because the guidelines are not yet supported by case histories, responders are encouraged to demonstrate creativity in their proposals in order to ensure that a comprehensive package is delivered.

This project must be completed by September 30, 2003. Due to the expedited nature of the contract, preference will be given to responders that can demonstrate substantial experience in working with both the taconite industry and air quality rules. Each contract responder must list the taconite companies that it has worked for in the past five years and that it is currently working for. If an existing contract is in place, the responder must explain why the new proposal does not create a conflict of interest.

The contractor will be expected to work directly with MPCA staff, representatives of individual facilities and any appointed contacts for the industry as a whole. Representatives of the taconite industry will be involved in the selection process and in reviewing draft work products, including the draft final report.

Goal

The MPCA expects an overall assessment of the effects of the BART requirements on the taconite industry that can be used by both the industry and the MPCA for planning purposes and as the basis of further technical work. The analysis should provide each taconite facility with enough information to use as a baseline to begin a detailed assessment if required. Furthermore, the analysis should be structured to help ensure that each facility conducts its engineering assessments the same way, thereby promoting the consistency that will aid the MPCA's review of those assessments. The MPCA also expects that the project will provide enough baseline information to initiate its own preliminary assessments, which are likely to be necessary to develop state implementation plan (SIP) submittals that will be due to EPA between 2006 and 2008.

Sample Tasks

1. Summarize EPA regional haze regulations as they apply to the taconite industry.

2. Summarize BART requirements as they apply to the industry.

3. Identify existing state and federal rules (e. g. Maximum Achievable Control Technology) that might help identify what BART is for the industry. Summarize the likely impacts of known future regulations. Include Michigan and Canadian requirements if appropriate.

4. Identify facilities that may be subject to BART requirements (the MPCA has already done a survey that could be incorporated here).

5. Using EPA's draft BART guidance (or final if available), identify in a general sense, the control technology options for the industry. The draft guidance was published in the Federal Register on July 20, 2001 (FR July 20, 2001 p. 38108-38135). Consider:
   - Available retrofit options [FR July 20, 2001 p. 38122] (include options from both outside and within the taconite industry)
   - Control equipment in place or likely to be in place [FR July 20, 2001 p. 38123]
   - The capital and operating costs of the control options [FR July 20, 2001 p. 38125]
   - The remaining useful life of the facility [FR July 20, 2001 p. 38126]
   - Energy and non-air quality environmental impacts of controls [FR July 20, 2001 p. 38129]
   - The control effectiveness of each option [FR July 20, 2001 p. 38126]
   - The "affordability" of controls [FR July 20, 2001 p. 38131]

6. Estimate the reductions in visibility degrading pollutants (NO_x, SO_2, $PM_{2.5}$ ((or PM_{10} if equivalent)), VOC, NH_4) from control options.

7. Consider the cost implications of implementing BART at those sources that supply needed services (such as fuel and power providers) to the taconite companies. Include an investigation of the capability of those suppliers to pass their costs along to the taconite industry, an estimate of the magnitude of the cost transfer, and an assessment of the likely effects of transferring those costs on the economic (affordability) analyses that the taconite companies must perform.

The MPCA expects that items 5 and 6 will form the bulk of the deliverables of the project. The MPCA's selection process will be based largely on how proposals address these items and the degree of creativity in each proposal.

The contractor will work closely with industry and MPCA personnel. Depending on the details of the proposal, it is possible that the contractor will prepare outlines or rough drafts of certain products, which will be reviewed or appended by industry or MPCA staff. The number of steps relying on such MPCA or industry input should be kept to a minimum.

The contract will begin on the date stated in the contract or upon full execution of the contract, whichever is later, and will be completed by September 30, 2003.

Responders are encouraged to propose additional tasks or activities if they will substantially improve the results of the project. These items should be separated from the required items on the cost proposal.

This request for proposal does not obligate the state to award a contract or complete the project, and the state reserves the right to cancel the solicitation if it is considered to be in its best interest.

Prospective responders who have any questions regarding this request for proposal may contact:

Stuart Arkley, Project Manager
Policy & Planning Division
Minnesota Pollution Control Agency
520 Lafayette Road, St. Paul, MN 55155

stuart.arkley@pca.state.mn.us

Telephone: 651-296-7774
Fax: 651-296-8676

Other personnel are **NOT** authorized to discuss this request for proposal with responders, before the proposal submission deadline. Contact regarding this RFP with any personnel not listed above could result in disqualification.

Questions must be submitted in writing (fax and e-mail will be accepted) by December 30, 2002. The MPCA will attempt to respond within 7 days of receipt of each question, depending on the complexity of the question and the total number of questions received. Copies of questions and MPCA responses will be sent to all responders to this request for proposal.

Pre-Proposal Question and Answer Meeting

The MPCA has scheduled a meeting at its St. Paul office on December 19, 2002, at 10 a.m. for the purpose of providing time for potential responders to ask questions about this project. All potential responders are invited to attend. The MPCA will be represented by the Project Manager and other key staff. Representatives of the taconite industry that plan to be involved in the selection process may also participate. Anyone interested in attending should confirm attendance by December 16, 2002. If no confirmations are received the meeting will be canceled.

Proposal Content

The following will be considered minimum contents of the proposal:

1. A statement of the objectives, goals, and tasks to show or demonstrate the responder's view of the nature of the contract.

2. A description of the deliverables to be provided by the responder.

3. An outline of the responder's background and experience with examples of similar work done by the responder and a list of personnel who will conduct the project, detailing their training, work experience, and hourly fees. No change in personnel assigned to the project will be permitted without the written approval of the state program manager.

4. A detailed work plan that will identify the major tasks to be accomplished and be used as a scheduling and managing tool, as well as the basis for invoicing.

5. Identification of the level of the MPCA's participation in the contract, as well as any other services to be provided by the MPCA, and details of cost allowances for this participation.

All proposals must be sent to:

Stuart Arkley, Project Manager
Policy & Planning Division
Minnesota Pollution Control Agency
520 Lafayette Road, St. Paul, MN 55155

All proposals must be received not later than 2:30 p.m., Central Time, on January 6, 2003, as indicated by a notation made by the MPCA Receptionist or Policy & Planning Division support staff.

Late proposals will not be considered.

All costs incurred in responding to this RFP will be borne by the responder.
Fax and e-mail responses will not be considered.

Submit three copies of the work proposal (not to include the cost proposal, which must be provided separately) and one set of work samples. Proposals are to be sealed in mailing envelopes or packages with the responder's name and address written on the outside. Each copy of the proposal must be signed in ink by an authorized member of the firm.

Provide one copy of the cost proposal in a separately sealed envelope clearly marked on the outside "Cost Proposal" along with the firm's name. For purposes of completing the cost proposal, the state does not make regular payments based upon the passage of time, it only pays for services performed or work delivered after it is accomplished.

Proposals will be evaluated on "best value" as 80 percent qualifications and 20 percent on cost considerations. The cost proposal will not be opened by the review committee until after the qualifications points are awarded.

Proposal Evaluation

All responses received by the deadline will be evaluated by representatives of the MPCA and a small group of representatives of the taconite industry. In some instances, an interview may be part of the evaluation process. A 100-point scale will be used to create the final evaluation recommendation. The factors and weighting on which proposals will be judged are:

1.	Work plan	40%
2.	Qualifications/experience of personnel working on the project	25%
3.	Cost detail	20%
4.	Expressed understanding of project objectives	10%
5.	Qualifications/experience of company	5%

General Requirements

Affidavit of Noncollusion

Each responder must complete the attached Affidavit of Noncollusion and include it with the response.

Conflicts of Interest

Responder must provide a list of all entities with which it has relationships that create, or appear to create, a conflict of interest with the work that is contemplated in this request for proposals. The list should indicate the name of the entity, the relationship, and a discussion of the conflict.

Disposition of Responses

All materials submitted in response to this RFP will become property of the State and will become public record in accordance with Minnesota Statutes, section 13.591, after the evaluation process is completed. Pursuant to the statute, completion of the evaluation process occurs when the government entity has completed negotiating the contract with the selected vendor. If the Responder submits information in response to this RFP that it believes to be trade secret materials, as defined by the Minnesota Government Data Practices Act, Minn. Stat. § 13.37, the Responder must:

- clearly mark all trade secret materials in its response at the time the response is submitted,
- include a statement with its response justifying the trade secret designation for each item, and
- defend any action seeking release of the materials it believes to be trade secret, and indemnify and hold harmless the State, its agents and employees, from any judgments or damages awarded against the State in favor of the party requesting the materials, and any and all costs connected with that defense. This indemnification survives the State's award of a contract. In submitting a response to this RFP, the Responder agrees that this indemnification survives as long as the trade secret materials are in possession of the State.

The State will not consider the prices submitted by the Responder to be proprietary or trade secret materials.

Contingency Fees Prohibited

Pursuant to Minnesota Statutes Section 10A.06, no person may act as or employ a lobbyist for compensation that is dependent upon the result or outcome of any legislation or administrative action.

Sample Contract

You should be aware of the State's standard contract terms and conditions in preparing your response. A sample State of Minnesota Professional/Technical Services Contract is attached for your reference. Much of the language reflected in the contract is required by statute. If you take exception to any of the terms, conditions or language in the contract, you must indicate those exceptions in your response to the RFP; certain exceptions may result in your proposal being disqualified from further review and evaluation. Only those exceptions indicated in your response to the RFP will be available for discussion or negotiation.

Reimbursements

Reimbursement for travel and subsistence expenses actually and necessarily incurred by the as a result of the contract will be in no greater amount than provided in the current "Commissioner's Plan" promulgated by the commissioner of Employee Relations. Reimbursements will not be made for travel and subsistence expenses incurred outside Minnesota unless it has received the State's prior written approval for out of state travel. Minnesota will be considered the home state for determining whether travel is out of state.

Organizational Conflicts of Interest

The responder warrants that, to the best of its knowledge and belief, and except as otherwise disclosed, there are no relevant facts or circumstances which could give rise to organizational conflicts of interest. An organizational conflict of interest exists when, because of existing or planned activities or because of relationships with other persons, a vendor is unable or potentially unable to render impartial assistance or advice to the State, or the vendor's objectivity in performing the contract work is or might be otherwise impaired, or the vendor has an unfair competitive advantage. The responder agrees that, if after award, an organizational conflict of interest is discovered, an immediate and full disclosure in writing must be made to the Assistant Director of the Department of Administration's Materials Management Division which must include a description of the action which the contractor has taken or proposes to take to avoid or mitigate such conflicts. If an organization conflict of interest is determined to exist, the State may, at its discretion, cancel the contract. In the event the responder was aware of an organizational conflict of interest prior to the award of the contract and did not disclose the conflict to the contracting officer, the State may terminate the contract for default. The provisions of this clause must be included in all subcontracts for work to be performed similar to the service provided by the prime contractor, and the terms "contract," "contractor," and "contracting officer" modified appropriately to preserve the State's rights.

State Employees

In compliance with Minn. Stat. § 16C.07, the availability of this work is being offered to state employees. The State will evaluate the responses of any state employee, along with other responses to this Request for Proposals.

STATE OF MINNESOTA
AFFIDAVIT OF NONCOLLUSION

I swear (or affirm) under the penalty of perjury:

1. That I am the Responder (if the Responder is an individual), a partner in the company (if the Responder is a partnership), or an officer or employee of the responding corporation having authority to sign on its behalf (if the Responder is a corporation);

2. That the attached proposal submitted in response to the ________________________ Request for Proposals has been arrived at by the Responder independently and has been submitted without collusion with and without any agreement, understanding or planned common course of action with, any other Responder of materials, supplies, equipment or services described in the Request for Proposal, designed to limit fair and open competition;

3. That the contents of the proposal have not been communicated by the Responder or its employees or agents to any person not an employee or agent of the Responder and will not be communicated to any such persons prior to the official opening of the proposals; and

4. That I am fully informed regarding the accuracy of the statements made in this affidavit.

Responder's Firm Name:____
Authorized Signature: ____

Date: __________________

Subscribed and sworn to me this ________ day of __________

Notary Public

My commission expires: ________

If you take exception to any of the terms, conditions or language in the contract, you must indicate those exceptions in your response to the RFP; certain exceptions may result in your proposal being disqualified from further review and evaluation. Only those exceptions indicated in your response to the RFP will be available for discussion or negotiation.

STATE OF MINNESOTA
PROFESSIONAL AND TECHNICAL SERVICES CONTRACT

This contract is between the State of Minnesota, acting through its _______________ ("State") and _________ ("Contractor").

Recitals

1. Under Minn. Stat. § 15.061 _________ the State is empowered to engage such assistance as deemed necessary.
2. The State is in need of _______.
3. The Contractor represents that it is duly qualified and agrees to perform all services described in this contract to the satisfaction of the State.

Contract

1 Term of Contract

1.1 ***Effective date*: ______________**, or the date the State obtains all required signatures under Minnesota Statutes Section 16C.05, subdivision 2, whichever is later.
The Contractor must not begin work under this contract until this contract is fully executed and the Contractor has been notified by the State's Authorized Representative to begin the work.

1.2 ***Expiration date*: ______________**, or until all obligations have been satisfactorily fulfilled, whichever occurs first.

1.3 ***Survival of Terms.*** The following clauses survive the expiration or cancellation of this contract: 8. Liability; 9. State Audits; 10. Government Data Practices and Intellectual Property; 13. Publicity and Endorsement; 14. Governing Law, Jurisdiction, and Venue; and 16 Data Disclosure.

2 Contractor's Duties

The Contractor, who is not a state employee, will:

3 Time

The Contractor must comply with all the time requirements described in this contract. In the performance of this contract, time is of the essence.

4 Consideration and Payment

4.1 ***Consideration***. The State will pay for all services performed by the Contractor under this contract as follows:

(A) ***Compensation.*** The Contractor will be paid

(B) ***Travel Expenses.*** Reimbursement for travel and subsistence expenses actually and necessarily incurred by the Contractor as a result of this contract will not exceed $___________ ; provided that the Contractor will be reimbursed for travel and subsistence expenses in the same manner and in no greater amount than provided in the current "Commissioner's Plan" promulgated by the commissioner of Employee Relations. The Contractor will not be reimbursed for travel and subsistence expenses incurred outside Minnesota unless it has received the State's prior written approval for out of state travel. Minnesota will be considered the home state for determining whether travel is out of state.

(C) ***Total Obligation.*** The total obligation of the State for all compensation and reimbursements to the Contractor under this contract will not exceed $ ____________.

4.2. ***Payment***

(A) ***Invoices.*** The State will promptly pay the Contractor after the Contractor presents an itemized invoice for the services actually performed and the State's Authorized Representative accepts the invoiced services. Invoices must be submitted timely and according to the following schedule:

(B) ***Retainage.*** Under Minnesota Statutes Section 16C.08, subdivision 5(b), no more than 90% of the amount due under this contract may be paid until the final product of this contract has been reviewed by the State's agency head. The balance due will be paid when the State's agency head determines that the Contractor has satisfactorily fulfilled all the terms of this contract.

(C) ***Federal funds.*** (Where applicable, if blank this section does not apply) Payments under this contract will be made from federal funds obtained by the State through Title ______ CFDA number _________ of the __________ Act of _____. The Contractor is responsible for compliance with all federal requirements imposed on these funds and accepts full financial responsibility for any requirements imposed by the Contractor's failure to comply with federal requirements.

5 Conditions of Payment

All services provided by the Contractor under this contract must be performed to the State's satisfaction, as determined at the sole discretion of the State's Authorized Representative and in accordance with all applicable federal, state, and local laws, ordinances, rules, and regulations. The Contractor will not receive payment for work found by the State to be unsatisfactory or performed in violation of federal, state, or local law.

6 Authorized Representatives

The State's Authorized Representative is ____________, or his/her successor, and has the responsibility to monitor the Contractor's performance and the authority to accept the services provided under this contract. If the services are satisfactory, the State's Authorized Representative will certify acceptance on each invoice submitted for payment.

The Contractor's Authorized Representative is __________, or his/her successor. If the Contractor's Authorized Representative changes at any time during this contract, the Contractor must immediately notify the State.

7 Assignment, Amendments, Waiver, and Contract Complete

7.1 ***Assignment.*** The Contractor may neither assign nor transfer any rights or obligations under this contract without the prior consent of the State and a fully executed Assignment Agreement, executed and approved by the same parties who executed and approved this contract, or their successors in office.

7.2 ***Amendments.*** Any amendment to this contract must be in writing and will not be effective until it has been executed and approved by the same parties who executed and approved the original contract, or their successors in office.

7.3 ***Waiver.*** If the State fails to enforce any provision of this contract, that failure does not waive the provision or its right to enforce it.

7.4 ***Contract Complete.*** This contract contains all negotiations and agreements between the State and the Contractor. No other understanding regarding this contract, whether written or oral, may be used to bind either party.

8 Liability

The Contractor must indemnify, save, and hold the State, its agents, and employees harmless from any claims or causes of action, including attorney's fees incurred by the State, arising from the performance of this contract by the Contractor or the Contractor's agents or employees. This clause will not be construed to bar any legal remedies the Contractor may have for the State's failure to fulfill its obligations under this contract.

9 State Audits

Under Minn. Stat. § 16C.05, subd. 5, the Contractor's books, records, documents, and accounting procedures and practices relevant to this contract are subject to examination by the State and/or the State Auditor or Legislative Auditor, as appropriate, for a minimum of six years from the end of this contract.

10 Government Data Practices and Intellectual Property

10.1. ***Government Data Practices.*** The Contractor and State must comply with the Minnesota Government Data Practices Act, Minn. Stat. Ch. 13, as it applies to all data provided by the State under this contract, and as it applies to all data created, collected, received, stored, used, maintained, or disseminated by the Contractor under this contract. The civil remedies of Minn. Stat. § 13.08 apply to the release of the data referred to in this clause by either the Contractor or the State.

If the Contractor receives a request to release the data referred to in this Clause, the Contractor must immediately notify the State. The State will give the Contractor instructions concerning the release of the data to the requesting party before the data is released.

10.2. ***Intellectual Property Rights.***

(A) *Intellectual Property Rights.* The State owns all rights, title, and interest in all of the intellectual property rights, including copyrights, patents, trade secrets, trademarks, and service marks in the Works and Documents *created and paid for under this contract*. Works means all inventions, improvements, discoveries (whether or not patentable), databases, computer programs, reports, notes, studies, photographs, negatives, designs, drawings, specifications, materials, tapes, and disks conceived, reduced to practice, created or originated by the Contractor, its employees, agents, and subcontractors, either individually or jointly with others in the performance of this contract. Works includes "Documents." Documents are the originals of any databases, computer programs, reports, notes, studies, photographs, negatives, designs, drawings, specifications, materials, tapes, disks, or other materials, whether in tangible or electronic forms, prepared by the Contractor, its employees, agents, or subcontractors, in the performance of this contract. The Documents will be the exclusive property of the State and all such Documents must be immediately returned to the State by the Contractor upon completion or cancellation of this contract. To the extent possible, those Works eligible for copyright protection under the United States Copyright Act will be deemed to be "works made for hire." The Contractor assigns all right, title, and interest it may have in the Works and the Documents to the State. The Contractor must, at the request of the State, execute all papers and perform all other acts necessary to transfer or record the State's ownership interest in the Works and Documents.

(B) *Obligations*

1. *Notification*. Whenever any invention, improvement, or discovery (whether or not patentable) is made or conceived for the first time or actually or constructively reduced to practice by the Contractor, including its employees and subcontractors, in the performance of this contract, the Contractor will immediately give the State's Authorized Representative written notice thereof, and must promptly furnish the Authorized Representative with complete information and/or disclosure thereon.

2. *Representation.* The Contractor must perform all acts, and take all steps necessary to ensure that all intellectual property rights in the Works and Documents are the sole property of the State, and that neither Contractor nor its employees, agents, or subcontractors retain any interest in and to the Works and Documents. The Contractor represents and warrants that the Works and Documents do not and will not infringe upon any intellectual property rights of other persons or entities. Notwithstanding Clause 8, the Contractor will indemnify; defend, to the extent permitted by the Attorney General; and hold harmless the State, at the Contractor's expense, from any action or claim brought against the State to the extent that it is based on a claim that all or part of the Works or Documents infringe upon the intellectual property rights of others. The Contractor will be responsible for payment of any and all such claims, demands, obligations, liabilities, costs, and damages, including but not limited to, attorney fees. If such a claim or action arises, or

in the Contractor's or the State's opinion is likely to arise, the Contractor must, at the State's discretion, either procure for the State the right or license to use the intellectual property rights at issue or replace or modify the allegedly infringing Works or Documents as necessary and appropriate to obviate the infringement claim. This remedy of the State will be in addition to and not exclusive of other remedies provided by law.

11 Workers' Compensation

The Contractor certifies that it is in compliance with Minn. Stat. § 176.181, subd. 2, pertaining to workers' compensation insurance coverage. The Contractor's employees and agents will not be considered State employees. Any claims that may arise under the Minnesota Workers' Compensation Act on behalf of these employees or agents and any claims made by any third party as a consequence of any act or omission on the part of these employees or agents are in no way the State's obligation or responsibility.

12 Publicity and Endorsement

12.1 ***Publicity***. Any publicity regarding the subject matter of this contract must identify the State as the sponsoring agency and must not be released without prior written approval from the State's Authorized Representative. For purposes of this provision, publicity includes notices, informational pamphlets, press releases, research, reports, signs, and similar public notices prepared by or for the Contractor individually or jointly with others, or any subcontractors, with respect to the program, publications, or services provided resulting from this contract.

12.2 ***Endorsement***. The Contractor must not claim that the State endorses its products or services.

13 Governing Law, Jurisdiction, and Venue

Minnesota law, without regard to its choice-of-law provisions, governs this contract. Venue for all legal proceedings out of this contract, or its breach, must be in the appropriate state or federal court with competent jurisdiction in Ramsey County, Minnesota.

14 Data Disclosure

Under Minn. Stat. § 270.66, and other applicable law, the Contractor consents to disclosure of its social security number, federal employer tax identification number, and/or Minnesota tax identification number, already provided to the State, to federal and state agencies and state personnel involved in the payment of state obligations. These identification numbers may be used in the enforcement of federal and state laws which could result in action requiring the Contractor to file state tax returns, pay delinquent state tax liabilities, if any, or pay other state liabilities.

15 Payment to Subcontractors

(If applicable) As required by Minn. Stat. § 16A.1245, the prime contractor must pay all subcontractors, less any retainage, within 10 calendar days of the prime contractor's receipt of payment from the State for undisputed services provided by the subcontractor(s) and must pay interest at the rate of one and one-half percent per month or any part of a month to the subcontractor(s) on any undisputed amount not paid on time to the subcontractor(s).

16 Minn. Stat. § 181.59 The vendor will comply with the provisions of Minn. Stat. § 181.59 which requires: Every contract for or on behalf of the state of Minnesota, or any county, city, town, township, school, school district, or any other district in the state, for materials, supplies, or construction shall contain provisions by which the contractor agrees: (1) That, in the hiring of common or skilled labor for the performance of any work under any contract, or any subcontract, no contractor, material supplier, or vendor, shall, by reason of race, creed, or color, discriminate against the person or persons who are citizens of the United States or resident aliens who are qualified and available to perform the work to which the employment relates; (2) That no contractor, material supplier, or vendor, shall, in any manner, discriminate against, or intimidate, or prevent the employment of any person or persons identified in clause (1) of this section, or on being hired, prevent, or conspire to prevent, the person or persons from the performance of work under any contract on account of race, creed, or color; (3) That a violation of this section is a misdemeanor; and (4) That this contract may be canceled or terminated by the state, county, city, town, school board, or any other person authorized to grant the contracts for employment, and all money due, or to become due under the contract, may be forfeited for a second or any subsequent violation of the terms or conditions of this contract.

17 Termination

17.1 ***Termination by the State.*** The State or commissioner of Administration may cancel this contract at any time, with or without cause, upon 30 days' written notice to the Contractor. Upon termination, the Contractor will be entitled to payment, determined on a pro rata basis, for services satisfactorily performed.

17.2 ***Termination for Insufficient Funding***. The State may immediately terminate this contract if it does not obtain funding from the Minnesota Legislature, or other funding source; or if funding cannot be continued at a level sufficient to allow for the payment of the services covered here. Termination must be by written or fax notice to the Contractor. The State is not obligated to pay for any services that are provided after notice and effective date of termination. However, the Contractor will be entitled to payment, determined on a pro rata basis, for services satisfactorily performed to the extent that funds are available. The State will not be assessed any penalty if the contract is terminated because of the decision of the Minnesota Legislature, or other funding source, not to appropriate funds. The State must provide the Contractor notice of the lack of funding within a reasonable time of the State's receiving that notice.

ATTACHMENT C

March 18, 2003, Working Group Meeting Minutes

MPCA Taconite BART Project
March 18, 2003, Working Group Meeting Minutes

List of Working Group Attendees (in alphabetical order):

Name	Representing	E-mail Address	Phone Number
Brad Anderson	EVTAC	brada@evtac.com	(218) 744-7849
Stuart Arkley	MPCA	stuart.arkley@state.mn.us	(651) 296-7774
Nick Axtell	Fond du Lac	nickaxtell@fdlrez.com	(218) 878-8012
Dick Cordes	MPCA	richard.cordes@state.mn.us	(651) 296-8157
Sarah Disch	Barr Engineering Co.	sdisch@barr.com	(952) 832-2789
Latisha Gietzen (via conference call)	National Steel Pellet Co.	lgietzen@nationalsteel.com	(218) 778-8672
Beth Havlik	Barr Engineering Co.	bhavlik@barr.com	(952) 832-2640
Gus Josephson	Ispat Inland Mining Co.	grjoseph@ispatinlandmining.com	(218) 749-5910
Jack Kennedy	Barr Engineering Co.	jkennedy@barr.com	(952) 832-2913
Brandon Krogh (via conference call)	MN Power	bkrogh@mnpower.com	(218) 723-3954
David Pohlman	National Park Service	david_pohlman@nps.gov	(651) 290-3801
George Pruchnofski	Barr Engineering Co.	gpruchnofski@barr.com	(952) 832-2638
Joel Trinkle	Barr Engineering Co.	jtrinkle@barr.com	(952) 832-2870
Joy Wiecks	Fond du Lac	joywiecks@fdlrez.com	(218) 878-8008

Review of Barr's Work Plan:

I. Task 1 – Hold Working Group Coordination Meeting
   a. Introductions (see attendee list above)
   b. Communication
      i. E-mail all correspondence to Stuart Arkley; Stuart will forward as needed
      ii. Stuart will disseminate reports
   c. Project deliverables
      i. Optional Task 1 was chosen by MPCA not to be completed
      ii. Optional Task 2 was chosen by MPCA to be completed
   d. General Regional Haze (RH) and Best Available Retrofit Technology (BART) discussion
      i. RH funding – federal (EPA) dollars, of which some is allocated to meeting Federal RH regulations. September 30 project deadline is established by MPCA to match end of Federal government's fiscal year.
      ii. Why taconite industry?
         1. MPCA BART Survey found many taconite companies have BART-eligible units
         2. Taconite industry is unique and localized in Minnesota
         3. Many utilities and sugar beet companies also on Survey
         4. Utilities will likely be dealt with through other planning organizations or trade organizations
         5. Primary BART-eligible units at sugar beet companies are external combustion units, so they can look to utilities for guidance
      iii. Agencies potentially involved in working group
         1. Central States Regional Air Planning Association (CenRAP) / Central States Air Resource Agencies (CenSARA)
            a. CenRAP includes tribal organizations and deals specifically with RH
            b. Joy Wiecks and Brandon Krogh are on CenRAP; they will disseminate information to the group as appropriate

2. EPA
    a. No specific expertise in taconite compared to MPCA staff; they may assist in review of documents but will not be actively involved, since it is the state's responsibility.
    b. Tim Smith at EPA in Research Triangle Park, NC, oversees regional haze implementation from a Federal level. We may work with Tim as necessary regarding interpretation of RH and BART provisions to this project.
3. MPCA
4. Federal Land Managers (FLMs)
5. Michigan Department of Environmental Quality (MDEQ):
    a. Two taconite plants in Michigan
    b. Working group felt that at least informal communications with a relevant organization in Michigan is appropriate
    c. MDEQ will not have representation; however, we will informally communicate with LADCO (see next item)
6. Lake Michigan Air Directors Consortium (LADCO):
    a. Joy Wiecks will carbon copy Mike Koerber, director of LADCO, on relevant communications and reports

iv. User/Audience of Project Deliverables
1. Deliverables should help Taconite industry in completing individual BART evaluations and promote consistency in the methods used by individual facilities
2. Deliverables should help MPCA in reviewing future BART evaluations by taconite industry

v. Class I Areas of concern:
1. Voyageurs and Boundary Waters in northern MN
2. Isle Royale has generally been excluded in the past by FLMs due to proximity – will re-evaluate as part of Optional Task 2, if necessary
3. Rainbow Lakes in WI does not have a visibility air quality related value (AQRV)

II. Task 2 – Conduct Taconite Industry Regional Haze Regulatory Study

a. Task 2A – Review MPCA BART survey and categorize emission units that may be subject to BART

i. Reviewed handout of categorized BART-eligible sources at MN taconite plants

ii. BART-eligible sources
1. Induration furnaces
2. PM point process sources
3. PM fugitive process sources

iii. Definition of taconite iron ore processing plant (where does facility start?)
1. MACT definition vs. PSD definition
2. Precedent
    a. Stuart will check at MPCA for other sectors
    b. Barr and MPCA will conference call with Tim Smith, EPA (at Research Triangle Park)

iv. BART-eligible sources: propose omitting from list
1. External combustion – covered separately under separate source category (but some level of review will be necessary in order to complete Optional Task 2, and probably Tasks 3 and 4)
2. Internal combustion
    a. No threshold in Guidance
    b. All emergency backup for electrical capabilities
    c. Small emissions, used infrequently
3. Zn melt furnaces
    a. Reasonable to assume control not affordable
    b. Discuss insignificant activities with Tim Smith

4. Mining (see II.a.ii. above)
5. Co-gen electric plants
    a. Outside of scope
    b. Covered separately under separate source category

b. Task 2B – Apply current EPA regional haze regulations and BART guidance to the taconite industry
    i. Status of proposed MACT
        1. EPA issued proposed MACT, invited and received comments
        2. Meeting 3/18/03 AM with rule writer Steve Fruh and Conrad Chin to discuss industry's comments
        3. Delisting proposal in June 2003; final rule by August 2003
        4. Risk assessment will not help industry - Hg and fibers may become political issues

c. Task 2E – Finalize Report of Taconite Industry Regional Haze Regulatory Study
    i. It was noted that the deadline for comments is incorrect. Barr will revise and re-submit the work scope to the working group.

III. Task 3 – Conduct General Taconite Industry BART Screening
    a. Task 3A – Identify control technologies and practices for each emission unit category
        i. Visibility-impairing pollutants of concern: fine particulate matter, NOx, and SO2
        ii. Ammonia – Stuart will discuss any potential ammonia emissions in the Air Toxics Emissions Inventory (ATEI) at taconite plants with Chun Yi Wu, MPCA
        iii. VOC – not a pollutant that needs detailed analysis, since induration furnaces must have high oxygen levels, thus oxidizing VOC to products of combustion
    b. Task 3D – Evaluate economic, energy, and environmental impacts
        i. Attempt to make economic analysis cost-scalable
        ii. Hypothetical taconite facility – concern that a single representative facility will not meet the needs of the industry without also looking at the entire range of facilities. Barr to propose a hypothetical taconite facility to the working group before beginning this task.
    c. Task 3F – Finalize Report of Taconite Industry BART Evaluation
        i. It was noted that the deadline for comments is incorrect. Barr will revise and re-submit the work scope to the working group.

IV. Task 4 – Conduct BART Affordability of Controls Evaluation
    a. See outline by George Pruchnofski of Barr

V. Optional Task 2 – Perform CALPUFF Visibility Impacts Screening Analysis
    a. Reviewed handout map of the six taconite plants in relation to the receptor grid for Voyageurs and Boundary Waters
    b. Concern was raised as to the scalability of results from a few individual units to an entire plant. Although this is currently not one of the primary objectives of the analysis, Barr will investigate the scalability of results to an entire facility.

VI. Action Items from Meeting
    a. Barr to summarize meeting minutes and update deadlines in Barr's scope of work
    b. MPCA to internally discuss the merits of inviting other agencies to participate in working group
    c. Stuart Arkley will work with Chun Yi Wu at MPCA regarding any ammonia emissions from the taconite industry and communicate findings to Barr
    d. MPCA and Barr to discuss with EPA about inclusion/exclusion of certain units (specifically, mining operations) in a BART evaluation; summarize these discussions with EPA and communicate findings to working group
    e. Barr to propose hypothetical taconite facility in Task 3D and Optional Task 2

Handouts at Meeting:

- Attachment 1: Barr's project work scope – the document attached to these minutes has been revised to incorporate corrected deadlines for report comments

- Attachment 2: Preliminary categorization of BART-eligible units at the Minnesota taconite plants
- Attachment 3: Map showing Minnesota taconite plants in relation to Voyageurs and Boundary Waters
- Attachment 4: Outline for Task 4 of the project

Project Deliverables

Table 1 on the following page describes each proposed project deliverable and provides a schedule for completion. Our schedule assumes a project initiation date of March 3, 2003. The schedule for completion is subject to change if the project begins later.

As described in the work plan, Barr proposes to prepare two key reports for this project. The reports will combine the individual tasks necessary to meet project objectives 1 through 4 in the Project Overview and Objectives section of this proposal. By completing only three reports for the project rather than submitting individual reports for each task, overall project costs are significantly reduced and review time by the working group is optimized. As a result, Barr expects to complete the required items of this project by the end of August, one month ahead of the September 30, 2003 required completion date.

Table 1. Summary of project deliverables and schedule for completion

Work Plan Deliverable	Description of Deliverable and Relationship to Project Objectives	Schedule for Completion
Task 1 Deliverables: Agenda and summary minutes of working group kick-off meeting	Barr will prepare an agenda and summarize minutes of the working group kick-off meeting, which will be scheduled for the week of March 10, 2003.	Agenda: March 7 Minutes: March 18
Task 2 Deliverables: Report on "Taconite Industry Regional Haze Regulatory Study" (working title; all final titles subject to working group approval)	Barr will provide for the working group's review an initial draft and a final version of the regulatory study, which will fulfill project objectives 1 and 2 in the Project Overview and Objectives section of this proposal.	Draft: April 18 Final: May 23
Task 3 Deliverables: Report on "Taconite Industry BART Evaluation"	Barr will provide for the working group's review an initial draft and a final version of the BART evaluation report, which fulfills project objective 3 in the Project Overview and Objectives section of this proposal.	Draft: June 30 Final: August 22
Task 4 Deliverable: Summary Report on the BART affordability issue as applied to the taconite industry	Barr will prepare a report to the working group summarizing discussions on the BART affordability issue and provide pass-through cost information, which fulfills project objective 4 in the Project Overview and Objectives section of this proposal.	Draft: July 14 Final: August 29
Routine progress reports	Barr will provide progress reports detailing work performed, upcoming tasks to be completed, budget status, and schedule status.	Every four weeks, consistent with invoice frequency
Optional Task 1 Deliverable: Customized BART evaluation tools for the taconite industry	If this optional task is chosen, Barr will provide user-friendly input and output screens and a user guide for the cost spreadsheets so that taconite facilities can uniformly perform BART evaluations.	September 19 or four weeks after notice is given to proceed with this task, whichever is later
Optional Task 2 Deliverable: Results of CALPUFF visibility impacts screening analysis	If this optional task is chosen, Barr will provide a memorandum summarizing results of a CALPUFF dispersion modeling analysis estimating the visibility impacts of a hypothetical taconite facility before and after BART application.	September 26 or five weeks after notice is given to proceed with this task, whichever is later

The proposed work plan is comprised of four primary tasks. Two optional tasks are also provided for your consideration.

- Task 1: Hold working group coordination meeting
- Task 2: Conduct taconite industry regional haze regulatory study
  [includes RFP sample tasks 1 through 4]
- Task 3: Conduct general taconite industry BART screening
  [includes RFP sample tasks 5 (except affordability issue) and 6]
- Task 4: Evaluate BART affordability issues
  [includes RFP sample task 5 (affordability issue only) and 7]
- Optional Task 1: Customize BART evaluation tools for the taconite industry
- Optional Task 2: Perform CALPUFF visibility impacts screening analysis

Task 1. Hold Working Group Coordination Meeting

The working group—MPCA personnel, representatives of the Minnesota taconite plants, and Barr's primary project team members—will meet at Barr's Minneapolis office during the week of March 10, 2003. Barr will prepare a meeting agenda, which will be submitted to the MPCA during the week of March 3, 2003. The purpose of the meeting is three-fold:

- **Provide contact information.** The working group will introduce themselves and provide their contact information and their roles in this project. Discussion should cover the need to include other participants, such as Michigan Department of Environmental Quality (MDEQ), EPA, or CENSARA (Central States Air Resource Agencies) staff, in the working group.
- **Establish lines of communication.** The working group will decide on verbal, electronic, and written lines of communication.
- **Review work plan.** The working group will review this work plan in detail and confirm important points and assumptions that best meet the project objectives, such as choosing emission unit categories and how the work products will be used in completing analyses outside the scope of this project.

We anticipate that this meeting will last two to three hours. Following the meeting, Barr will prepare a summary of the meeting minutes and route this via e-mail to the working group.

Task 1 Barr Deliverables:

- Agenda for the working group kick-off meeting
- Summary minutes of the working group kick-off meeting

Task 1 Assumptions:

- The kick-off meeting will be held at Barr's Minneapolis office.
- All working group members will participate in this meeting either in person or by conference call.
- MPCA will provide results of the BART survey for the individual taconite facilities (needed for Task 2A) prior to or at this meeting.

Task 2. Conduct Taconite Industry Regional Haze Regulatory Study

Task 2 will fulfill project objectives 1 and 2 outlined in the "Project Overview and Objectives" section of this proposal. It has five elements, detailed below as Tasks 2A–2E.

Task 2A: Review MPCA BART survey and categorize emission units that may be subject to BART

An appropriate first step in evaluating BART for a group of sources is to categorize emission units within the "taconite ore processing facilities" source category. Grouping several emission units into a few categories will allow efficient evaluation of available control technology options for the industry. Based on Barr's experience with the taconite industry, we propose three emission unit categories on which the regulatory study in Task 2 and the BART evaluation in Task 3 will be based. These categories will be reviewed and finalized as part of this task.

Table 2 on the following page identifies the three proposed emission unit categories, individual emission units in each category, and expected control technology options to be evaluated.

Task 2A Assumptions:

- Results from the MPCA BART survey for the individual taconite plants will be provided prior to or at the working group kick-off meeting in Task 1.
- For purposes of estimating cost and schedule for this project, up to three emission unit types (e.g., induration furnace, crusher, and cooler) will be evaluated.

Table 2. Preliminary Taconite Emission Unit Categories and Control Technology Options

Source Types	Sources	Control Technology Options
Particulate Fugitive Source	- Main roads - Transfer conveyors - Stockpiles - Pellet loading	- Dust suppression - Enclosure
Particulate Point Source	- Ore dump pits - Ore conveyors - Crushers - Additive handling - Pellet coolers - Screens - Product conveyors	- Enclosure - Scrubber (low/high efficiency) - Fabric filter - ESP
Induration Point Source (Particulate and Combustion Emissions)	Straight grate furnaces at: - Hibbing Taconite Company - Ispat-Inland Steel Mining Company - Northshore Mining Company Grate-kiln systems at: - US Steel Minnesota Ore Operations - National Steel Pellet Company - EVTAC Mining, LLC	Particulate: - Multiclone - Baghouse - Scrubber - ESP/WESP SO_2: - WESP - Scrubber (low/high efficiency) NOx: - Combustion control - Low-NOx burner - SCR - SNCR

Task 2B: Apply current EPA regional haze regulations and BART guidance to the taconite industry

Barr will review and summarize the final regional haze regulations and the proposed BART guidance as it applies to the taconite industry. In addition, we will summarize recent court opinions concerning the legality of certain BART provisions. This is considered necessary to help form an appropriate procedure for evaluating BART (see Task 3) that will not conflict with present or future EPA regulations or guidance.

Task 2B Assumptions:

- The 1999 regional haze regulations, the 2001 BART guidance, and the May and September 2002 court rulings comprise the documents for review under this task. Any new regulations or court decisions issued after January 6, 2003 may impact the schedule, scope, and cost of the project.

Task 2C: Summarize existing and possible future standards of performance applicable to the taconite industry

Barr will examine the following state and federal standards of performance in order to better understand how the taconite industry meets applicable emission limits:

- Federal Standards of Performance for Metallic Mineral Processing Plants, 40 CFR part 60 subpart LL
- *Proposed* National Emission Standards for Hazardous Air Pollutants for Taconite Iron Ore Processing, 40 CFR part 63 subpart RRRRR
- Minnesota Rules, Chapter 7011
- Michigan Air Pollution Control Rules, Parts 3 through 12
- Canadian provincial air quality standards of performance (focus on provinces where taconite processing facilities are located)

In addition, Barr will gather and review BACT determinations from EPA, MPCA, and MDEQ for taconite facilities as well as operating permits for Minnesota and Michigan taconite facilities to pull together site-specific standards of performance and the methods used by these companies to meet them.

The Taconite Iron Ore Processing NESHAPs was proposed on December 18, 2002. The taconite industry is in the process of reviewing available options to petition a delisting of Taconite Iron Ore Processing as a source category. As part of this project, Barr will evaluate the status of this effort and report our findings.

Task 2C Assumptions:

- Barr may request from MPCA a copy of taconite facility operating permits and related documents that we do not have in-house. We assume that MPCA will provide a copy of the requested documents in a timely manner.

Task 2D: Prepare initial draft report of Taconite Industry Regional Haze Regulatory Study

We will outline our findings from Tasks 2A through 2C in a draft report, which will be submitted via e-mail as an Acrobat PDF file to the working group by April 18 for review.

Task 2D Barr Deliverables:

- Draft report of Taconite Industry Regional Haze Regulatory Study.

Task 2E: Finalize report of Taconite Industry Regional Haze Regulatory Study

The working group will review the initial draft report. Upon request, we will schedule a meeting in early- to mid-April at Barr's Minneapolis office to discuss the report. Assuming that all comments are provided to Barr by May 14, the final report will be prepared and sent to the MPCA contact by May 23, 2003.

Task 2E Barr Deliverables:

- Final report of Taconite Industry Regional Haze Regulatory Study.

Task 2E Assumptions:

- Barr assumes that attending a review meeting and finalizing the draft report will involve a level of effort up to 20 person-hours.

Task 3. Conduct General Taconite Industry BART Screening

Task 3 fulfills project objective 3 in the "Project Overview and Objectives" section of this proposal. It has six elements, Tasks 3A–3F, which are consistent with the steps in EPA's BART guidance but have been customized to allow the use of a recent BACT study performed for a new taconite plant.

In 2000, Barr began a prevention of significant deterioration (PSD) air permitting project for an entirely new taconite facility. The BACT analysis that Barr performed for that project—herein referred to as the "2000 Taconite BACT Analysis"—will serve as an excellent starting point for development of tools and evaluation of each BART step.

Task 3A: Identify control technologies and practices for each emission unit category

The first step in a case-by-case BART engineering analysis is to identify all available retrofit control technologies. Beginning with the emission unit category list in Table 2 (Task 2A), Barr will identify available control technologies and practices for the following pollutants of concern:[1]

- Sulfur dioxide
- Nitrogen oxides
- Particulate matter
- Volatile organic compounds
- Ammonia

For particulate matter, PM_{10} will be used as an indicator, consistent with EPA's BART guidance. Barr assumes that actual $PM_{2.5}$ emissions data for the taconite emission units of concern will not be available for this study.

Based on our experience in estimating and measuring pollutant emissions from taconite facilities, we believe that no significant ammonia emissions sources exist from taconite processes. Therefore, Barr assumes that ammonia will not need to be addressed in a BART evaluation unless it is released as ammonia slip from a control technology application (e.g., injected into a SCR catalyst bed or in an ESP).

As shown in Table 2, Barr has narrowed the pollutants of concern for the induration point sources to PM_{10}, SO_2, and NOx. An induration furnace has relatively low VOC emissions because oxygen must be maintained at a high level in the unit as part of normal operation; therefore, the only practical VOC

[1] See 66 FR 38119 for an EPA discussion on visibility-impairing pollutants.

emissions control is good operating practices. Other VOC control technologies will not be evaluated for induration point sources.

In Task 3A, Barr will update its list of available control technology options by contacting control technology vendors and reviewing relevant journals (since 2000), websites, and other relevant literature listed in the EPA BART guidance.[2]

Task 3A Assumptions:

- For particulate matter, PM_{10} will be used as an indicator. Emissions of $PM_{2.5}$ will not be addressed in this study.
- A BART evaluation for VOC emissions from induration point sources will not be performed.
- Ammonia will not need to be addressed in a BART evaluation for the taconite industry, unless it is emanated as ammonia slip from a control technology option.

Task 3B: Eliminate technically infeasible control options

The second step in EPA's BART guidance is to review the technical feasibility of control options identified in Task 3A. As part of the 2000 Taconite BACT Analysis, we performed a technical feasibility analysis for all available control options. To meet BART guidance objectives, we will:

- Assess the technical feasibility of any new control technology options identified in Task 3A
- Re-examine the technical feasibility determination made in the 2000 Taconite BACT Analysis as applied to a BART source

A control technology that is considered technically feasible for a new source may not be technically feasible as a retrofit.[3] For example, in the 2000 Taconite BACT Analysis, selective catalytic reduction (SCR) was considered a technically feasible control technology for a proposed grate-kiln furnace because the furnace could be designed to accommodate the catalyst bed at an appropriate temperature and pressure. It is possible that SCR may be found to be technically infeasible for an existing furnace not designed to accommodate SCR.

Task 3B Assumptions:

- We assume that up to two new control technologies will be identified in Task 3A and require a technical feasibility determination beyond the list of existing control technology options identified in Table 2. This project assumption is also important for Tasks 3C and 3D.

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[2] See 66 FR 38123 for EPA's list of information sources to review for potentially applicable retrofit control technology alternatives.

[3] In 64 FR 38123, EPA states, "We do not consider BART as a requirement to redesign the source when considering available control alternatives."

Task 3C: Rank remaining control technologies by control effectiveness

The third step in EPA's BART guidance is to rank technically feasible control technologies by their control effectiveness. Barr evaluated the percent control efficiency of technical feasible control technologies as part of the 2000 Taconite BACT Analysis. Barr will update the control-effectiveness data based on conversations with control technology vendors in Task 3A.

Task 3D: Evaluate economic, energy, and environmental impacts

The fourth step in EPA's BART guidance is to perform an impacts analysis related to the economic, energy, and non-air quality environmental aspects of the control technology options. During the 2000 Taconite BACT Analysis, we evaluated these impacts for control technologies installed at a new source. Barr will re-examine the impacts of all technically feasible control technologies as they apply to an existing taconite facility.

To provide meaningful information from this task, Barr will use a hypothetical taconite facility representative of the taconite industry, as determined in Task 1 by the working group, to estimate the cost and impacts of control technology options.

Task 3E: Prepare initial draft report of Taconite Industry BART Evaluation

Barr will outline its findings from Tasks 3A through 3D in a report to MPCA. The draft report and corresponding control equipment cost spreadsheets will be submitted via e-mail to the working group by June 30, 2003, for review.

Task 3E Barr Deliverables:

- Draft report of Taconite Industry BART Evaluation.

Task 3F: Finalize report of Taconite Industry BART Evaluation

The working group will review the initial draft report. Upon request, we will schedule a meeting in June at Barr's Minneapolis office to review and discuss the report. Assuming that all comments will be provided to Barr by July 31, the final report will be prepared and sent to the MPCA point of contact by August 22, 2003.

Task 3F Barr Deliverables:

- Final report of Taconite Industry BART Evaluation including calculation spreadsheets.

Task 3F Assumptions:

- Barr assumes that attending a review meeting and finalizing the draft report can be accomplished with a level of effort up to 30 person-hours.

Task 4. Conduct BART Affordability of Controls Evaluation

The affordability of controls is an important consideration for the state and the taconite industry, given the financial condition of the industry and foreign competition's current impact on taconite product prices. Current and anticipated market price trends from publicly available literature will be reviewed and summarized. Other industry-wide affordability issues will also be briefly examined and summarized if brought forward by working group members and agreed to by the MPCA. However, facility-specific affordability issues will not be considered as part of this project.

Barr will contact major taconite industry service providers (e.g., power, fuel) to attempt to identify pass-through costs to the taconite industry that are anticipated to result from the regional haze SIP. The results of these communications will be reported.

Additionally, Barr will prepare a cost summary template to present total anticipated taconite facility internal costs and pass-through costs of service providers. The template will allow for the presentation of cost increases per ton of product. These costs can be compared to the current and anticipated price for taconite product. A sample table will be completed using the results of Task 3 and the anticipated pass-through costs obtained from service providers.

Task 4 Barr Deliverable:

- A draft summary report and cost table will be prepared for work group review and comment. Barr will consider the comments in preparing the final memo and cost table.

Task 4 Assumptions:

- General industry affordability issues will be addressed. Facility-specific affordability issues are outside the scope of this project.

Optional Task 1. Customize BART Evaluation Tools for the Taconite Facilities

An optional task that Barr will perform upon MPCA's request is to customize control cost spreadsheets and related tools for use by the taconite industry. The spreadsheets will have user-friendly input screens that each facility can use to input site-specific information necessary to evaluate BART for an emission unit and control technology option and review the results. Accompanying these tools will be a guide that describes steps and procedures that the user should follow. The key value in this tool is that it provides ease of use and uniformity in both the initial BART evaluation by the taconite industry and subsequent review by a regulatory agency.

Optional Task 1 Barr Deliverable:

- Spreadsheets, related tools, and a user's guide to help provide consistent site-specific BART evaluations for the taconite industry.

Optional Task 1 Assumptions:

- Spreadsheets and tools developed in Task 3 will form the basis for the customized BART evaluation tools. No new spreadsheets or other tools are expected to be developed as part of this task.

Optional Task 2. Perform CALPUFF visibility impacts screening analysis.

An optional task that Barr will perform upon MPCA's request is a visibility impacts screening analysis for a hypothetical taconite facility before and after BART application. Barr will use the Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report (December 2000) as protocol for estimating visibility impacts. The FLAG report calls for use of the CALMET/CALPUFF/CALPOST modeling system, with specific information provided for relative humidity to estimate the effects of hygroscopic particles.

Barr will propose and the working group will confirm the pollutant emission rates and relevant source parameters for a hypothetical taconite facility that will be used in the analysis. The working group will also decide upon three post-BART scenarios to estimate different levels of controlled emissions from the modeled emission units. Barr will model the visibility impairment from the facility as a "change in extinction" in units of percent, in accordance with the FLAG report. The following results will be provided in a memorandum:

- Pre-BART change in extinction from the facility
- Post-BART change in extinction from the facility for each scenario
- Contribution/culpability from each pollutant and source.

We believe that this analysis will serve to prepare a framework for future dispersion modeling analyses. Applications of the results of this modeling analysis by itself are limited.

Optional Task 2 Barr Deliverable:

- Memorandum summarizing results of the visibility impacts screening analysis before and after BART application.

Optional Task 2 Assumptions:

- Barr will not perform modeling iterations using different emission rates or source parameters other than those established initially by the working group.
- Barr will use an existing CALMET system that was prepared for another project. Electronic CALMET input and output files will not be provided to MPCA. Electronic CALPUFF and CALPOST input and output files will be provided to MPCA upon request.
- The December 2000 FLAG Report will serve as the basis for modeling protocol. Additions or changes to FLAG guidance since this report will not be incorporated into this analysis.
- The results of this analysis will have limited application. A comprehensive dispersion modeling analysis with existent facility emissions data will be needed in order to determine visibility impacts on Class I areas from the taconite industry.

Preliminary Categorization of BART-Eligible Sources at MN Taconite Plants

STATIONARY SOURCE NAME/LOCATION	EMISSION UNIT ID (2)	EMISSION UNIT DESCRIPTION	Primary Source Type	Secondary Source Type
EVTAC Mining - Mine	FS004	Unpaved Roads - Hauling Waste & Ore	1.00 Particulate Fugitive Source	1.01 Unpaved Roads
EVTAC Mining - Mine	FS008	Unpaved Roads - Lt truck traffic around mine	1.00 Particulate Fugitive Source	1.01 Unpaved Roads
EVTAC Mining - Plant	FS001	Unpaved Roads - Coarse tailings to tailings basin	1.00 Particulate Fugitive Source	1.01 Unpaved Roads
EVTAC Mining - Plant	FS012	Unpaved Roads - Lt truck traffic around plant	1.00 Particulate Fugitive Source	1.01 Unpaved Roads
EVTAC Mining - Mine	FS006	North Mine Transfer to Surge	1.00 Particulate Fugitive Source	1.02 Material Handling (Conveyor)
EVTAC Mining - Mine	FS007	South Mine Transfer to Surge	1.00 Particulate Fugitive Source	1.02 Material Handling (Conveyor)
EVTAC Mining - Plant	FS005	Coarse Ore Surge Dump	1.00 Particulate Fugitive Source	1.02 Material Handling (Conveyor)
EVTAC Mining - Plant	FS029	Fire Ore Surge (9F to 10 transfer)	1.00 Particulate Fugitive Source	1.02 Material Handling (Conveyor)
EVTAC Mining - Plant	FS030	Fine Ore Surge (10 to pile transfer)	1.00 Particulate Fugitive Source	1.02 Material Handling (Conveyor)
EVTAC Mining - Plant	FS031	Line 1 Pellet Transfer (21 to 21B)	1.00 Particulate Fugitive Source	1.02 Material Handling (Conveyor)
EVTAC Mining - Mine	FS002	Truck Unloading	1.00 Particulate Fugitive Source	1.03 Material Handling (Mobile Equipment)
EVTAC Mining - Plant	FS024	Pellet Reclaim - Pocket to pile 2 (FEL)	1.00 Particulate Fugitive Source	1.03 Material Handling (Mobile Equipment)
EVTAC Mining - Mine	FS001	Wind Erosion - Waste & Ore Stockpiles	1.00 Particulate Fugitive Source	1.03 Wind Erosion (Stockpile)
EVTAC Mining - Mine	FS003	Wind Erosion - Ballast Stockpile	1.00 Particulate Fugitive Source	1.03 Wind Erosion (Stockpile)
EVTAC Mining - Plant	FS004	Wind Erosion - Concentrate Stockpiles	1.00 Particulate Fugitive Source	1.03 Wind Erosion (Stockpile)
EVTAC Mining - Plant	FS014	Pelet Reclaim - Screen to belt 22 transfer	1.00 Particulate Fugitive Source	1.04 Material Handling (Other)
EVTAC Mining - Plant	FS033	Pellet Loadout Railcar Loading	1.00 Particulate Fugitive Source	1.04 Material Handling (Other)
EVTAC Mining - Plant	FS002	Wind Erosion - Tailings basin (active area)	1.00 Particulate Fugitive Source	1.04 Wind Erosion (Other)
US Steel Minn Ore Operations - Minntac	FS	Central Shops - multiple sources	1.00 Particulate Fugitive Source	Uncategorized
EVTAC Mining - Mine	001	North Primary Crushing	2.00 Particulate Point Source	2.01 Crushing
EVTAC Mining - Mine	002	North Secondary Crushing	2.00 Particulate Point Source	2.01 Crushing
EVTAC Mining - Mine	004	South Primary Crushing	2.00 Particulate Point Source	2.01 Crushing
EVTAC Mining - Mine	005	South Secondary Crushing	2.00 Particulate Point Source	2.01 Crushing
EVTAC Mining - Plant	005	Third Stage Crusher 1	2.00 Particulate Point Source	2.01 Crushing
EVTAC Mining - Plant	006	Third Stage Crusher 2	2.00 Particulate Point Source	2.01 Crushing
EVTAC Mining - Plant	007	Third Stage Crusher 3	2.00 Particulate Point Source	2.01 Crushing
EVTAC Mining - Plant	008	Third Stage Crusher 4	2.00 Particulate Point Source	2.01 Crushing
EVTAC Mining - Plant	009	Third Stage Crusher 5	2.00 Particulate Point Source	2.01 Crushing
EVTAC Mining - Plant	011	Fourth Stage Crusher 1	2.00 Particulate Point Source	2.01 Crushing
EVTAC Mining - Plant	012	Fourth Stage Crusher 2	2.00 Particulate Point Source	2.01 Crushing
EVTAC Mining - Plant	013	Fourth Stage Crusher 3	2.00 Particulate Point Source	2.01 Crushing
EVTAC Mining - Plant	014	Fourth Stage Crusher 4	2.00 Particulate Point Source	2.01 Crushing
EVTAC Mining - Plant	015	Fourth Stage Crusher 5	2.00 Particulate Point Source	2.01 Crushing
EVTAC Mining - Plant	016	Fourth Stage Crusher 6	2.00 Particulate Point Source	2.01 Crushing
EVTAC Mining - Plant	017	Fourth Stage Crusher 7	2.00 Particulate Point Source	2.01 Crushing
EVTAC Mining - Plant	018	Fourth Stage Crusher 8	2.00 Particulate Point Source	2.01 Crushing
Ispat Inland Mining Co.	001	Primary Crusher	2.00 Particulate Point Source	2.01 Crushing
Ispat Inland Mining Co.	003	Secondary Crusher System	2.00 Particulate Point Source	2.01 Crushing
Ispat Inland Mining Co.	004	Secondary Crusher System	2.00 Particulate Point Source	2.01 Crushing
Ispat Inland Mining Co.	005	Secondary Crusher System	2.00 Particulate Point Source	2.01 Crushing
Ispat Inland Mining Co.	007	Tertiary Crusher System	2.00 Particulate Point Source	2.01 Crushing
Ispat Inland Mining Co.	008	Tertiary Crusher System	2.00 Particulate Point Source	2.01 Crushing
Ispat Inland Mining Co.	009	Tertiary Crusher System	2.00 Particulate Point Source	2.01 Crushing
Ispat Inland Mining Co.	010	Tertiary Crusher System	2.00 Particulate Point Source	2.01 Crushing
National Steel Pellet Co.	001	Gyrator Crusher - Primary Crusher No. 1	2.00 Particulate Point Source	2.01 Crushing
National Steel Pellet Co.	002	Gyrator Crusher - Primary Crusher No. 2	2.00 Particulate Point Source	2.01 Crushing
Northshore Mining Co. - Babbitt	007	Crusher 2	2.00 Particulate Point Source	2.01 Crushing

Preliminary Categorization of BART-Eligible Sources at MN Taconite Plants

STATIONARY SOURCE NAME/LOCATION	EMISSION UNIT ID (2)	EMISSION UNIT DESCRIPTION	Primary Source Type	Secondary Source Type
Northshore Mining Co. - Babbitt	008	Crusher 2a	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	013	Step I Coarse Crusher	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	014	Step I Coarse Crusher	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	015	Step II Coarse Crusher	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	016	Step II Coarse Crusher	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	054	Secondary Crusher L1	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	055	Secondary Crusher L2	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	056	Secondary Crusher L3	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	057	Secondary Crusher L4	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	069	Tertiary Crusher L1	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	070	Tertiary Crusher L2	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	071	Tertiary Crusher L3	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	072	Tertiary Crusher L4	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	073	Tertiary Crusher L5	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	074	Tertiary Crusher L6	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	075	Tertiary Crusher L7	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	076	Tertiary Crusher L8	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	077	Tertiary Crusher L9	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	078	Tertiary Crusher L10	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	079	Tertiary Crusher L11	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	080	Tertiary Crusher L12	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	081	Tertiary Crusher L13	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	082	Tertiary Crusher L14	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	083	Tertiary Crusher L15	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	084	Tertiary Crusher L16	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	093	Secondary Crusher L6	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	094	Secondary Crusher L7	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	095	Secondary Crusher L8	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	096	Secondary Crusher L9	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	097	Secondary Crusher L10	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	103	Secondary Crusher L5	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	106	Secondary Crusher L11	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	107	Secondary Crusher L12	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	108	Secondary Crusher L13	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	109	Secondary Crusher L14	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	110	Secondary Crusher L15	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	128	Tertiary Crusher L18	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	129	Tertiary Crusher L19	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	130	Tertiary Crusher L20	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	131	Tertiary Crusher L21	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	132	Tertiary Crusher L22	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	133	Tertiary Crusher L23	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	134	Tertiary Crusher L24	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	135	Tertiary Crusher L25	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	136	Tertiary Crusher L26	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	137	Tertiary Crusher L27	2.00 Particulate Point Source	2.01 Crushing
US Steel Minn Ore Operations - Minntac	138	Tertiary Crusher L28	2.00 Particulate Point Source	2.01 Crushing

Preliminary Categorization of BART-Eligible Sources at MN Taconite Plants

STATIONARY SOURCE NAME/LOCATION	EMISSION UNIT ID (2)	EMISSION UNIT DESCRIPTION	Primary Source Type	Secondary Source Type
US Steel Minn Ore Operations - Minntac	139	Tertiary Crusher L29	2.00 Particulate Point Source	2.01 Crushing
EVTAC Mining - Mine	003	North Loadout Tunnel	2.00 Particulate Point Source	2.02 Material Handling - Ore
EVTAC Mining - Mine	006	South Loadout Tunnel	2.00 Particulate Point Source	2.02 Material Handling - Ore
EVTAC Mining - Plant	001	Crude Ore Unloading Pan Feeders	2.00 Particulate Point Source	2.02 Material Handling - Ore
EVTAC Mining - Plant	002	Crude Ore Unloading	2.00 Particulate Point Source	2.02 Material Handling - Ore
EVTAC Mining - Plant	004	Coarse Ore Surge Pan Feeders	2.00 Particulate Point Source	2.02 Material Handling - Ore
EVTAC Mining - Plant	010	Third Stage Bins Conveyor	2.00 Particulate Point Source	2.02 Material Handling - Ore
EVTAC Mining - Plant	019	Fourth Stage Trip/Bin/Convey	2.00 Particulate Point Source	2.02 Material Handling - Ore
EVTAC Mining - Plant	020	Transfer House North	2.00 Particulate Point Source	2.02 Material Handling - Ore
EVTAC Mining - Plant	022	Transfer House South	2.00 Particulate Point Source	2.02 Material Handling - Ore
EVTAC Mining - Plant	023	No. 1 Rod Mill Feed	2.00 Particulate Point Source	2.02 Material Handling - Ore
EVTAC Mining - Plant	024	No. 2 Rod Mill Feed	2.00 Particulate Point Source	2.02 Material Handling - Ore
EVTAC Mining - Plant	025	No. 3 Rod Mill Feed	2.00 Particulate Point Source	2.02 Material Handling - Ore
EVTAC Mining - Plant	026	No. 4 Rod Mill Feed	2.00 Particulate Point Source	2.02 Material Handling - Ore
EVTAC Mining - Plant	027	No. 5 Rod Mill Feed	2.00 Particulate Point Source	2.02 Material Handling - Ore
Hibbing Taconite Co	001	Phase I Apron Feeder	2.00 Particulate Point Source	2.02 Material Handling - Ore
Hibbing Taconite Co	002	Phase II Apron Feeder	2.00 Particulate Point Source	2.02 Material Handling - Ore
Hibbing Taconite Co	003	Phase I Primary Ore Conveyor - Tail	2.00 Particulate Point Source	2.02 Material Handling - Ore
Hibbing Taconite Co	004	Phase II Primary Ore Conveyor - Tail	2.00 Particulate Point Source	2.02 Material Handling - Ore
Hibbing Taconite Co	005	Line No. 1 Mill Feed Conveyor	2.00 Particulate Point Source	2.02 Material Handling - Ore
Hibbing Taconite Co	006	Line No. 2 Mill Feed Conveyor	2.00 Particulate Point Source	2.02 Material Handling - Ore
Hibbing Taconite Co	007	Line No. 3 Mill Feed Conveyor	2.00 Particulate Point Source	2.02 Material Handling - Ore
Hibbing Taconite Co	008	Line No. 4 Mill Feed Conveyor	2.00 Particulate Point Source	2.02 Material Handling - Ore
Hibbing Taconite Co	009	Line No. 5 Mill Feed Conveyor	2.00 Particulate Point Source	2.02 Material Handling - Ore
Hibbing Taconite Co	010	Line No. 6 Mill Feed Conveyor	2.00 Particulate Point Source	2.02 Material Handling - Ore
Hibbing Taconite Co	011	Line No. 7 Mill Feed Conveyor	2.00 Particulate Point Source	2.02 Material Handling - Ore
Hibbing Taconite Co	012	Line No. 8 Mill Feed Conveyor	2.00 Particulate Point Source	2.02 Material Handling - Ore
Hibbing Taconite Co	013	Line No. 9 Mill Feed Conveyor	2.00 Particulate Point Source	2.02 Material Handling - Ore
Ispat Inland Mining Co.	002	Drop Onto Coarse Ore Pile Conveyor	2.00 Particulate Point Source	2.02 Material Handling - Ore
Ispat Inland Mining Co.	006	Outside Ore Transfer	2.00 Particulate Point Source	2.02 Material Handling - Ore
Ispat Inland Mining Co.	011	Fine Ore Drop Onto Two Underfeed Belts	2.00 Particulate Point Source	2.02 Material Handling - Ore
Ispat Inland Mining Co.	012	Fine Ore Drop Onto Intermediate Conveyor	2.00 Particulate Point Source	2.02 Material Handling - Ore
Ispat Inland Mining Co.	013	Fine Ore Drop Onto Rod Mill Bin Conveyor	2.00 Particulate Point Source	2.02 Material Handling - Ore
Ispat Inland Mining Co.	014	Fine Ore Drop Onto Rod Mill Bin Feeder	2.00 Particulate Point Source	2.02 Material Handling - Ore
Ispat Inland Mining Co.	015	Fine Ore Drop Into Rod Mill Bin	2.00 Particulate Point Source	2.02 Material Handling - Ore
Ispat Inland Mining Co.	016	Fine Ore Drop Onto Internal Conveyors	2.00 Particulate Point Source	2.02 Material Handling - Ore
Ispat Inland Mining Co.	017	Fine Ore Drop Into Rod Mills	2.00 Particulate Point Source	2.02 Material Handling - Ore
National Steel Pellet Co.	003	Conveyor Transfer - Drive house No. 1 Primary Conv	2.00 Particulate Point Source	2.02 Material Handling - Ore
National Steel Pellet Co.	004	Conveyor Transfer - Drive house No. 2 Primary Conv	2.00 Particulate Point Source	2.02 Material Handling - Ore
National Steel Pellet Co.	005	Conveyor Transfer - Crude Ore Feed	2.00 Particulate Point Source	2.02 Material Handling - Ore
National Steel Pellet Co.	006	Conveyor Transfer - Crude Ore Feed	2.00 Particulate Point Source	2.02 Material Handling - Ore
National Steel Pellet Co.	007	Conveyor Transfer - Crude Ore Feed	2.00 Particulate Point Source	2.02 Material Handling - Ore
National Steel Pellet Co.	008	Conveyor Transfer - Crude Ore Feed	2.00 Particulate Point Source	2.02 Material Handling - Ore
National Steel Pellet Co.	009	Conveyor Transfer - Crude Ore Feed	2.00 Particulate Point Source	2.02 Material Handling - Ore
National Steel Pellet Co.	010	Conveyor Transfer - Crude Ore Feed	2.00 Particulate Point Source	2.02 Material Handling - Ore
National Steel Pellet Co.	011	Conveyor Transfer - Crude Ore Feed	2.00 Particulate Point Source	2.02 Material Handling - Ore
National Steel Pellet Co.	012	Conveyor Transfer - Crude Ore Feed	2.00 Particulate Point Source	2.02 Material Handling - Ore

Preliminary Categorization of BART-Eligible Sources at MN Taconite Plants

STATIONARY SOURCE NAME/LOCATION	EMISSION UNIT ID (2)	EMISSION UNIT DESCRIPTION	Primary Source Type	Secondary Source Type
National Steel Pellet Co.	013	Conveyor Transfer - Crude Ore Feed	2.00 Particulate Point Source	2.02 Material Handling - Ore
National Steel Pellet Co.	014	Conveyor Transfer - Crude Ore Feed	2.00 Particulate Point Source	2.02 Material Handling - Ore
Northshore Mining Co. - Silver Bay	008	East Car Dump	2.00 Particulate Point Source	2.02 Material Handling - Ore
Northshore Mining Co. - Silver Bay	010	Crusher Storage Bins (E)	2.00 Particulate Point Source	2.02 Material Handling - Ore
Northshore Mining Co. - Silver Bay	016	Crushed Ore Conveyors	2.00 Particulate Point Source	2.02 Material Handling - Ore
Northshore Mining Co. - Silver Bay	017	Crusher Line 101	2.00 Particulate Point Source	2.02 Material Handling - Ore
Northshore Mining Co. - Silver Bay	018	Crusher Line 102	2.00 Particulate Point Source	2.02 Material Handling - Ore
Northshore Mining Co. - Silver Bay	019	Crusher Line 103	2.00 Particulate Point Source	2.02 Material Handling - Ore
Northshore Mining Co. - Silver Bay	020	Crusher Line 104	2.00 Particulate Point Source	2.02 Material Handling - Ore
Northshore Mining Co. - Silver Bay	031	East Transfer Bin	2.00 Particulate Point Source	2.02 Material Handling - Ore
Northshore Mining Co. - Silver Bay	044	East Storage Bins #101	2.00 Particulate Point Source	2.02 Material Handling - Ore
Northshore Mining Co. - Silver Bay	045	East Storage Bins #102	2.00 Particulate Point Source	2.02 Material Handling - Ore
Northshore Mining Co. - Silver Bay	046	East Storage Bins #103	2.00 Particulate Point Source	2.02 Material Handling - Ore
Northshore Mining Co. - Silver Bay	047	East Storage Bins #104	2.00 Particulate Point Source	2.02 Material Handling - Ore
Northshore Mining Co. - Silver Bay	048	East Storage Bins #105	2.00 Particulate Point Source	2.02 Material Handling - Ore
Northshore Mining Co. - Silver Bay	049	East Storage Bins #106	2.00 Particulate Point Source	2.02 Material Handling - Ore
Northshore Mining Co. - Silver Bay	050	East Storage Bins #107	2.00 Particulate Point Source	2.02 Material Handling - Ore
Northshore Mining Co. - Silver Bay	051	East Storage Bins #108	2.00 Particulate Point Source	2.02 Material Handling - Ore
Northshore Mining Co. - Silver Bay	052	East Storage Bins #109	2.00 Particulate Point Source	2.02 Material Handling - Ore
Northshore Mining Co. - Silver Bay	053	East Storage Bins #110	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	017	Step III Coarse Crusher & Lime Dump	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	018	Step III Coarse Crusher & Lime Dump	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	019	Step III Coarse Crusher & Lime Dump	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	020	Step III Coarse Crusher & Lime Dump	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	021	Step III Coarse Crusher & Lime Dump	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	022	Step I Coarse Crusher Pan Feeders	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	023	Step I Coarse Crusher Pan Feeders	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	024	Step II Coarse Crusher Pan Feeders	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	025	Step II Coarse Crusher Pan Feeders	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	026	Step III Coarse Crusher Pan Feeders & Lime Transfe	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	027	Step III Coarse Crusher Pan Feeders & Lime Transfe	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	034	Conveyor Transfer 005-006	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	035	Conveyor Transfer 005-006	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	036	Conveyor Transfer 010-001	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	037	Conveyor Transfer 010-001	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	038	Conveyor Transfer 010-001	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	039	Conveyor Transfer 010-001	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	040	Conveyor Transfer 005-006	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	041	Conveyor Transfer 004-005	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	042	Conveyor Transfer 004-005	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	043	Conveyor Transfer 004-005	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	044	Conveyor Transfer 004-005	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	045	Conveyor Transfer 004-005	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	046	Conveyor Transfer 004-005	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	047	Conveyor Transfer 011-02/03	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	048	Surge Pile/Reclaim 011-01	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	052	Conveyor Transfer 008-009	2.00 Particulate Point Source	2.02 Material Handling - Ore

Preliminary Categorization of BART-Eligible Sources at MN Taconite Plants

STATIONARY SOURCE NAME/LOCATION	EMISSION UNIT ID (2)	EMISSION UNIT DESCRIPTION	Primary Source Type	Secondary Source Type
US Steel Minn Ore Operations - Minntac	053	Conveyor Transfer 008-009	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	058	Conveyor Transfer 005 to 006	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	059	Conveyor Transfer 005 to 006	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	060	Conveyor Transfer 005 to 006	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	061	Conveyor Transfer 003 to 004	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	062	Conveyor Transfer 003 to 004	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	063	Conveyor Transfer 003 to 004	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	064	Conveyor Transfer 003 to 004	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	065	Tertiary Storage Bin 1-4	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	066	Tertiary Storage Bin 1-4	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	067	Tertiary Storage Bin 1-4	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	068	Tertiary Storage Bin 1-4	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	085	Tertiary Crusher 080 Bins 5-8	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	086	Tertiary Crusher 080 Bins 5-8	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	087	Tertiary Crusher 080 Bins 5-8	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	088	Tertiary Crusher 080 Bins 5-8	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	089	Tertiary Crusher 080 Bins 5-8	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	090	Tertiary Crusher 080 Bins 5-8	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	091	Tertiary Crusher 080 Bins 5-8	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	092	Tertiary Crusher 080 Bins 5-8	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	098	Conveyor Transfer 008 to 009	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	099	Conveyor Transfer 008 to 009	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	100	Conveyor Transfer 008 to 009	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	101	Conveyor Transfer 008 to 009	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	102	Storage Bin 070-02	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	104	Conveyor Transfer 008 to 009	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	105	Conveyor Transfer 008 to 009	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	111	Conveyor Transfer 001-070 Bin	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	112	Conveyor Transfer 003	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	113	Conveyor Transfer 003	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	114	Conveyor Transfer 003-004	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	115	Conveyor Transfer 003-004	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	116	Tertiary Storage 006-080 Bin	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	117	Tertiary Storage 006-080 Bin	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	118	Tertiary Storage 006-080 Bin	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	119	Tertiary Storage 006-080 Bin	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	120	Tertiary Storage 006-080 Bin	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	121	Tertiary Storage 006-080 Bin	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	122	Tertiary Storage 006-080 Bin	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	123	Tertiary Storage 006-080 Bin	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	124	Tertiary Storage 006-080 Bin	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	125	Tertiary Storage 006-080 Bin	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	126	Tertiary Storage 006-080 Bin	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	127	Tertiary Storage 006-080 Bin	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	140	Conveyor Transfer 005-006	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	141	Conveyor Transfer 005-006	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	144	Conveyor Transfer 009-020	2.00 Particulate Point Source	2.02 Material Handling - Ore

Preliminary Categorization of BART-Eligible Sources at MN Taconite Plants

STATIONARY SOURCE NAME/LOCATION	EMISSION UNIT ID (2)	EMISSION UNIT DESCRIPTION	Primary Source Type	Secondary Source Type
US Steel Minn Ore Operations - Minntac	145	Conveyor Transfer 009-020	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	146	Conveyor Transfer 009-020	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	147	Conveyor Transfer 009-020	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	148	Storage Bin L1,2	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	149	Storage Bin L1,2	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	150	Storage Bin L1,2	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	151	Storage Bin L1,2	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	152	Storage Bin L1,2	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	153	Storage Bin L1,2	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	154	Storage Bin L1,2	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	155	Storage Bin L3,4	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	156	Storage Bin L3,4	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	157	Storage Bin L3,4	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	158	Storage Bin L3,4	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	159	Storage Bin L3,4	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	160	Storage Bin L3,4	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	161	Storage Bin L3,4	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	162	Storage Bin L5,6	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	163	Storage Bin L5,6	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	164	Storage Bin L5,6	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	165	Storage Bin L5,6	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	166	Storage Bin L5,6	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	167	Storage Bin L5,6	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	168	Storage Bin L5,6	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	169	Storage Bin L7,8	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	170	Storage Bin L7,8	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	171	Storage Bin L7,8	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	172	Storage Bin L7,8	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	173	Storage Bin L7,8	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	174	Storage Bin L7,8	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	175	Storage Bin L7,8	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	176	Storage Bin L9,10	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	177	Storage Bin L9,10	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	178	Storage Bin L9,10	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	179	Storage Bin L9,10	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	180	Storage Bin L9,10	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	181	Storage Bin L9,10	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	182	Storage Bin L9,10	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	183	Storage Bin L11,12	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	184	Storage Bin L11,12	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	185	Storage Bin L11,12	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	186	Storage Bin L11,12	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	187	Storage Bin L11,12	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	188	Storage Bin L11,12	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	189	Storage Bin L11,12	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	190	Conveyor Transfer 009-020	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	191	Conveyor Transfer 009-020	2.00 Particulate Point Source	2.02 Material Handling - Ore

Preliminary Categorization of BART-Eligible Sources at MN Taconite Plants

STATIONARY SOURCE NAME/LOCATION	EMISSION UNIT ID (2)	EMISSION UNIT DESCRIPTION	Primary Source Type	Secondary Source Type
US Steel Minn Ore Operations - Minntac	192	Conveyor Transfer 009-020	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	193	Conveyor Transfer 009-020	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	194	Storage Bin L13,14	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	195	Storage Bin L13,14	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	196	Storage Bin L13,14	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	197	Storage Bin L13,14	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	198	Storage Bin L13,14	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	199	Storage Bin L13,14	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	200	Storage Bin L13,14	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	201	Storage Bin L15,16	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	202	Storage Bin L15,16	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	203	Storage Bin L15,16	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	204	Storage Bin L15,16	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	205	Storage Bin L15,16	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	206	Storage Bin L15,16	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	207	Storage Bin L15,16	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	208	Storage Bin L17,18	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	209	Storage Bin L17,18	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	210	Storage Bin L17,18	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	211	Storage Bin L17,18	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	212	Storage Bin L17,18	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	213	Storage Bin L17,18	2.00 Particulate Point Source	2.02 Material Handling - Ore
US Steel Minn Ore Operations - Minntac	214	Storage Bin L17,18	2.00 Particulate Point Source	2.02 Material Handling - Ore
EVTAC Mining - Plant	028	Limestone/Soda Ash Storage Bins	2.00 Particulate Point Source	2.03 Material Handling - Additive
EVTAC Mining - Plant	029	Additive Unloading	2.00 Particulate Point Source	2.03 Material Handling - Additive
EVTAC Mining - Plant	030	Line 2 Additive Storage Bins	2.00 Particulate Point Source	2.03 Material Handling - Additive
EVTAC Mining - Plant	031	Line 2 Additive Addition	2.00 Particulate Point Source	2.03 Material Handling - Additive
EVTAC Mining - Plant	032	Soda Ash/Binder Mixing	2.00 Particulate Point Source	2.03 Material Handling - Additive
EVTAC Mining - Plant	057	Soda Ash/Binder Day Bin 1	2.00 Particulate Point Source	2.03 Material Handling - Additive
EVTAC Mining - Plant	058	Soda Ash/Binder Addition	2.00 Particulate Point Source	2.03 Material Handling - Additive
EVTAC Mining - Plant	062	Soda Ash/Binder Day Bin 2	2.00 Particulate Point Source	2.03 Material Handling - Additive
Hibbing Taconite Co	016	Phase I Bentonite Day Bins	2.00 Particulate Point Source	2.03 Material Handling - Additive
Hibbing Taconite Co	017	Phase II Bentonite Day Bins	2.00 Particulate Point Source	2.03 Material Handling - Additive
Hibbing Taconite Co	028	Bentonite Storage Silo - East	2.00 Particulate Point Source	2.03 Material Handling - Additive
Hibbing Taconite Co	029	Bentonite Storage Silo - West	2.00 Particulate Point Source	2.03 Material Handling - Additive
Ispat Inland Mining Co.	018	Binder Transfer to Storage Silo	2.00 Particulate Point Source	2.03 Material Handling - Additive
Ispat Inland Mining Co.	019	Binder Transfer to Binder Shift Bins	2.00 Particulate Point Source	2.03 Material Handling - Additive
Ispat Inland Mining Co.	020	Binder Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
National Steel Pellet Co.	015	Additive Blending, Phase I	2.00 Particulate Point Source	2.03 Material Handling - Additive
National Steel Pellet Co.	016	Additive Blending, Phase II	2.00 Particulate Point Source	2.03 Material Handling - Additive
National Steel Pellet Co.	017	Addititive Silo, Phase I	2.00 Particulate Point Source	2.03 Material Handling - Additive
National Steel Pellet Co.	018	Addititive Silo, Phase II	2.00 Particulate Point Source	2.03 Material Handling - Additive
Northshore Mining Co. - Silver Bay	077	E Addititive Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
Northshore Mining Co. - Silver Bay	078	E Addititive Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
Northshore Mining Co. - Silver Bay	079	E Addititive Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
Northshore Mining Co. - Silver Bay	080	E Addititive Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
Northshore Mining Co. - Silver Bay	081	E Additive Bins 3-4	2.00 Particulate Point Source	2.03 Material Handling - Additive

Preliminary Categorization of BART-Eligible Sources at MN Taconite Plants

STATIONARY SOURCE NAME/LOCATION	EMISSION UNIT ID (2)	EMISSION UNIT DESCRIPTION	Primary Source Type	Secondary Source Type
Northshore Mining Co. - Silver Bay	082	E Additive Bins 5-6	2.00 Particulate Point Source	2.03 Material Handling - Additive
Northshore Mining Co. - Silver Bay	083	E Additive Unload	2.00 Particulate Point Source	2.03 Material Handling - Additive
Northshore Mining Co. - Silver Bay	084	E Additive Unload	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	217	L3 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	218	L3 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	219	L3 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	220	L3 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	236	S1 Bentonite Storage Bin	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	237	S1 Bentonite Storage Bin	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	238	S1 Bentonite Storage Bin	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	239	L2,3 Bentonite Day Bin	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	240	L2,3 Bentonite Day Bin	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	241	L2,3 Bentonite Day Bin	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	242	L2,3 Bentonite Day Bin	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	243	S1,2 Bentonite Unloading	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	244	S2 Bentonite Storage Bin	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	245	S2 Bentonite Storage Bin	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	246	S2 Bentonite Storage Bin	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	247	L4 Bentonite Day Bins	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	248	L4 Bentonite Day Bins	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	249	L4 Bentonite Day Bins	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	250	L4 Bentonite Day Bins	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	251	L4 Bentonite Day Bins	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	252	L4 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	253	L4 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	254	L4 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	255	L4 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	256	L4 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	268	L5 Bentonite Day Bins	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	269	L5 Bentonite Day Bins	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	270	L5 Bentonite Day Bins	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	271	L5 Bentonite Day Bins	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	272	L5 Bentonite Day Bins	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	273	L5 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	274	L5 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	275	L5 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	276	L5 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	277	L5 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	297	S3 Bentonite Storage	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	298	S3 Bentonite Storage	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	299	S3 Bentonite Storage	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	300	S3 Bentonite Storage	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	301	L6 Bentonite Day Bin	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	302	L6 Bentonite Day Bin	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	303	L6 Bentonite Day Bin	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	304	L6 Bentonite Day Bin	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	305	L6 Bentonite Day Bin	2.00 Particulate Point Source	2.03 Material Handling - Additive

Preliminary Categorization of BART-Eligible Sources at MN Taconite Plants

STATIONARY SOURCE NAME/LOCATION	EMISSION UNIT ID (2)	EMISSION UNIT DESCRIPTION	Primary Source Type	Secondary Source Type
US Steel Minn Ore Operations - Minntac	306	L6 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	307	L6 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	308	L6 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	309	L6 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	310	L6 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	320	L7 Bentonite Day Bin	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	321	L7 Bentonite Day Bin	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	322	L7 Bentonite Day Bin	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	323	L7 Bentonite Day Bin	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	324	L7 Bentonite Day Bin	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	325	L7 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	326	L7 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	327	L7 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	328	L7 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	329	L7 Bentonite Blending	2.00 Particulate Point Source	2.03 Material Handling - Additive
US Steel Minn Ore Operations - Minntac	367	Coal Unloading Silo	2.00 Particulate Point Source	2.04 Material Handling - Coal
US Steel Minn Ore Operations - Minntac	368	Coal Unloading Silo	2.00 Particulate Point Source	2.04 Material Handling - Coal
US Steel Minn Ore Operations - Minntac	369	Coal Unloading Silo	2.00 Particulate Point Source	2.04 Material Handling - Coal
US Steel Minn Ore Operations - Minntac	370	Coal Unloading Silo	2.00 Particulate Point Source	2.04 Material Handling - Coal
US Steel Minn Ore Operations - Minntac	371	Coal Unloading Silo	2.00 Particulate Point Source	2.04 Material Handling - Coal
US Steel Minn Ore Operations - Minntac	372	Coal Unloading Silo	2.00 Particulate Point Source	2.04 Material Handling - Coal
US Steel Minn Ore Operations - Minntac	373	Coal Unloading Silo	2.00 Particulate Point Source	2.04 Material Handling - Coal
US Steel Minn Ore Operations - Minntac	374	Coal Day Bin/Conveyor Transfer	2.00 Particulate Point Source	2.04 Material Handling - Coal
US Steel Minn Ore Operations - Minntac	375	Coal Day Bin/Conveyor Transfer	2.00 Particulate Point Source	2.04 Material Handling - Coal
US Steel Minn Ore Operations - Minntac	376	Coal Day Bin/Conveyor Transfer	2.00 Particulate Point Source	2.04 Material Handling - Coal
US Steel Minn Ore Operations - Minntac	377	Coal Day Bin/Conveyor Transfer	2.00 Particulate Point Source	2.04 Material Handling - Coal
US Steel Minn Ore Operations - Minntac	378	Coal Day Bin/Conveyor Transfer	2.00 Particulate Point Source	2.04 Material Handling - Coal
US Steel Minn Ore Operations - Minntac	379	Coal Day Bin/Conveyor Transfer	2.00 Particulate Point Source	2.04 Material Handling - Coal
US Steel Minn Ore Operations - Minntac	380	Coal Day Bin/Conveyor Transfer	2.00 Particulate Point Source	2.04 Material Handling - Coal
US Steel Minn Ore Operations - Minntac	381	Coal Day Bin/Conveyor Transfer	2.00 Particulate Point Source	2.04 Material Handling - Coal
US Steel Minn Ore Operations - Minntac	382	Coal Day Bin/Conveyor Transfer	2.00 Particulate Point Source	2.04 Material Handling - Coal
Ispat Inland Mining Co.	023	Grate Feed	2.00 Particulate Point Source	2.05 Straight Grate (Grate)
Hibbing Taconite Co	023	Pellet Machine Discharge Line No 1	2.00 Particulate Point Source	2.06 Straight Grate (Pellet Discharge)
Hibbing Taconite Co	024	Pellet Machine Discharge Line No 2	2.00 Particulate Point Source	2.06 Straight Grate (Pellet Discharge)
Hibbing Taconite Co	025	Pellet Machine Discharge Line No 3	2.00 Particulate Point Source	2.06 Straight Grate (Pellet Discharge)
Ispat Inland Mining Co.	027	Machine Discharge	2.00 Particulate Point Source	2.06 Straight Grate (Pellet Discharge)
EVTAC Mining - Plant	033	Line 2 Grate Feed	2.00 Particulate Point Source	2.07 Grate-Kiln (Grate)
EVTAC Mining - Plant	034	Line 2 Grate Discharge	2.00 Particulate Point Source	2.07 Grate-Kiln (Grate)
EVTAC Mining - Plant	037	Line 1 Grate Feed	2.00 Particulate Point Source	2.07 Grate-Kiln (Grate)
EVTAC Mining - Plant	038	Line 1 Grate Discharge	2.00 Particulate Point Source	2.07 Grate-Kiln (Grate)
US Steel Minn Ore Operations - Minntac	221	L3 Grate Feed	2.00 Particulate Point Source	2.07 Grate-Kiln (Grate)
US Steel Minn Ore Operations - Minntac	222	L3 Grate Discharge	2.00 Particulate Point Source	2.07 Grate-Kiln (Grate)
US Steel Minn Ore Operations - Minntac	257	L4 Grate Feed	2.00 Particulate Point Source	2.07 Grate-Kiln (Grate)
US Steel Minn Ore Operations - Minntac	258	L4 Grate Discharge	2.00 Particulate Point Source	2.07 Grate-Kiln (Grate)
US Steel Minn Ore Operations - Minntac	278	L5 Grate Feed	2.00 Particulate Point Source	2.07 Grate-Kiln (Grate)
US Steel Minn Ore Operations - Minntac	279	L5 Grate Discharge	2.00 Particulate Point Source	2.07 Grate-Kiln (Grate)
US Steel Minn Ore Operations - Minntac	311	L6 Grate Feed	2.00 Particulate Point Source	2.07 Grate-Kiln (Grate)

Preliminary Categorization of BART-Eligible Sources at MN Taconite Plants

STATIONARY SOURCE NAME/LOCATION	EMISSION UNIT ID (2)	EMISSION UNIT DESCRIPTION	Primary Source Type	Secondary Source Type
US Steel Minn Ore Operations - Minntac	312	L6 Grate Discharge	2.00 Particulate Point Source	2.07 Grate-Kiln (Grate)
US Steel Minn Ore Operations - Minntac	330	L7 Grate Feed	2.00 Particulate Point Source	2.07 Grate-Kiln (Grate)
US Steel Minn Ore Operations - Minntac	331	L7 Grate Discharge	2.00 Particulate Point Source	2.07 Grate-Kiln (Grate)
EVTAC Mining - Plant	035	Line 2 Kiln Cooler Discharge & Vibrating Feeders	2.00 Particulate Point Source	2.08 Grate-Kiln (Cooler)
EVTAC Mining - Plant	036	Line 2 Pellet Cooler Exhaust	2.00 Particulate Point Source	2.08 Grate-Kiln (Cooler)
EVTAC Mining - Plant	041	Line 1 Pellet Cooler Exhaust	2.00 Particulate Point Source	2.08 Grate-Kiln (Cooler)
National Steel Pellet Co.	025	Pellet Cooler, Phase I	2.00 Particulate Point Source	2.08 Grate-Kiln (Cooler)
National Steel Pellet Co.	026	Pellet Cooler, Phase II	2.00 Particulate Point Source	2.08 Grate-Kiln (Cooler)
US Steel Minn Ore Operations - Minntac	226	L3 Pellet Cooler Secondary Air	2.00 Particulate Point Source	2.08 Grate-Kiln (Cooler)
US Steel Minn Ore Operations - Minntac	227	L3 Cooler Vent Stack	2.00 Particulate Point Source	2.08 Grate-Kiln (Cooler)
US Steel Minn Ore Operations - Minntac	228	L3 Cooler Discharge	2.00 Particulate Point Source	2.08 Grate-Kiln (Cooler)
US Steel Minn Ore Operations - Minntac	262	L4 Pellet Cooler Secondary Air	2.00 Particulate Point Source	2.08 Grate-Kiln (Cooler)
US Steel Minn Ore Operations - Minntac	263	L4 Pellet Cooler Vent Stack	2.00 Particulate Point Source	2.08 Grate-Kiln (Cooler)
US Steel Minn Ore Operations - Minntac	283	L5 Pellet Cooler Secondary Air	2.00 Particulate Point Source	2.08 Grate-Kiln (Cooler)
US Steel Minn Ore Operations - Minntac	284	L5 Pellet Cooler Vent Stack	2.00 Particulate Point Source	2.08 Grate-Kiln (Cooler)
US Steel Minn Ore Operations - Minntac	316	L6 Pellet Cooler Secondary Air	2.00 Particulate Point Source	2.08 Grate-Kiln (Cooler)
US Steel Minn Ore Operations - Minntac	317	L6 Pellet Cooler Vent	2.00 Particulate Point Source	2.08 Grate-Kiln (Cooler)
US Steel Minn Ore Operations - Minntac	335	L7 Pellet Cooler Secondary Air	2.00 Particulate Point Source	2.08 Grate-Kiln (Cooler)
US Steel Minn Ore Operations - Minntac	336	L7 Pellet Cooler Vent	2.00 Particulate Point Source	2.08 Grate-Kiln (Cooler)
National Steel Pellet Co.	023	Cooler Dump Zone, Phase I	2.00 Particulate Point Source	2.09 Grate-Kiln (Pellet Discharge)
US Steel Minn Ore Operations - Minntac	265	L4 Cooler Discharge	2.00 Particulate Point Source	2.09 Grate-Kiln (Pellet Discharge)
US Steel Minn Ore Operations - Minntac	286	L5 Cooler Discharge	2.00 Particulate Point Source	2.09 Grate-Kiln (Pellet Discharge)
EVTAC Mining - Plant	104	Conveyor 22S	2.00 Particulate Point Source	2.10 Material Handling - Pellets
EVTAC Mining - Plant	105	Conveyor 22N	2.00 Particulate Point Source	2.10 Material Handling - Pellets
EVTAC Mining - Plant	106	Conveyor 23S	2.00 Particulate Point Source	2.10 Material Handling - Pellets
EVTAC Mining - Plant	107	Conveyor 23N	2.00 Particulate Point Source	2.10 Material Handling - Pellets
Hibbing Taconite Co	018	Phase I Hearth Layer Bin/Layer Feed	2.00 Particulate Point Source	2.10 Material Handling - Pellets
Hibbing Taconite Co	019	Phase II Hearth Layer Bin/Layer Feed	2.00 Particulate Point Source	2.10 Material Handling - Pellets
Hibbing Taconite Co	026	Pellet Hearth Layer Screening	2.00 Particulate Point Source	2.10 Material Handling - Pellets
Hibbing Taconite Co	027	Pellet Transfer House	2.00 Particulate Point Source	2.10 Material Handling - Pellets
Ispat Inland Mining Co.	021	Pellet Drop Onto Internal Hearth Layer Conveyor	2.00 Particulate Point Source	2.10 Material Handling - Pellets
Ispat Inland Mining Co.	022	Drop Into Hearth Layer Bin	2.00 Particulate Point Source	2.10 Material Handling - Pellets
Ispat Inland Mining Co.	024	Drop Into Hearth Layer Screen	2.00 Particulate Point Source	2.10 Material Handling - Pellets
Ispat Inland Mining Co.	025	Drop Onto Conveyor to Hearth Layer Bin	2.00 Particulate Point Source	2.10 Material Handling - Pellets
Ispat Inland Mining Co.	028	Drop Onto Conveyor to Pellet Splitter Bin	2.00 Particulate Point Source	2.10 Material Handling - Pellets
Ispat Inland Mining Co.	029	Drop Into Pellet Splitter Bin	2.00 Particulate Point Source	2.10 Material Handling - Pellets
Ispat Inland Mining Co.	030	Drop Onto Product Splitter Bin Conveyors	2.00 Particulate Point Source	2.10 Material Handling - Pellets
Ispat Inland Mining Co.	031	Drop Into P1-P2 Transfer House	2.00 Particulate Point Source	2.10 Material Handling - Pellets
Ispat Inland Mining Co.	032	Drop Onto P3 Pellet Pile Underfeed Conveyor	2.00 Particulate Point Source	2.10 Material Handling - Pellets
National Steel Pellet Co.	028	Pellet Product Conveyor - Phase I	2.00 Particulate Point Source	2.10 Material Handling - Pellets
National Steel Pellet Co.	032	Product Belts, Phase II	2.00 Particulate Point Source	2.10 Material Handling - Pellets
National Steel Pellet Co.	034	Conveyor Transfer - Pellet Pile to Loadout Conveyo	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	229	L3 Feeder 041/046 Belts	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	230	L3 041/046 Conveyor Belt Vent	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	231	L3 041/046 Conveyor Belt Vent	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	232	S1 Conveyor Transfer 042-043	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	233	S1 Conveyor Transfer 042-043	2.00 Particulate Point Source	2.10 Material Handling - Pellets

Preliminary Categorization of BART-Eligible Sources at MN Taconite Plants

STATIONARY SOURCE NAME/LOCATION	EMISSION UNIT ID (2)	EMISSION UNIT DESCRIPTION	Primary Source Type	Secondary Source Type
US Steel Minn Ore Operations - Minntac	234	L1 Conveyor Transfer 041-043	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	235	L1 Conveyor Transfer 041-043	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	264	L4 Conveyor Transfer Feeder	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	266	L4 Conveyor Transfer 041/046 to 042 Belts	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	267	L4 Conveyor Transfer 041/046 to 042 Belts	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	285	L5 Conveyor Transfer Feeder	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	287	L5 Conveyor Transfer Belts 041/046 to 042 Belts	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	288	L5 Conveyor Transfer Belts 041/046 to 042 Belts	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	289	Step I 043 Conveyor Vents	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	290	Step I 043 Conveyor Vents	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	291	Step I 043 Conveyor Vents	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	292	Step I 043 Conveyor Vents	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	293	Step I 043 Conveyor Vents	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	294	Step I 043 Conveyor Vents	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	295	S3 Conveyor Transfer	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	296	S3 Conveyor Transfer	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	318	L6 Conveyor Transfer	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	319	L6 Conveyor Transfer	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	337	L7 Conveyor Transfer	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	338	L7 Conveyor Transfer	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	339	Step I 043/044 Conveyor Transfer	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	340	Step I 043/044 Conveyor Transfer	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	341	Step III 042 Conveyor Vent	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	342	Step III 042 Conveyor Vent	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	343	Step III 043 Conveyor Vent	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	344	Step III 043 Conveyor Vent	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	345	Step III 044 Conveyor Vent	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	346	Step III 044 Conveyor Vent	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	347	Step III 044 Conveyor Vent	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	348	Step III 044 Conveyor Vent	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	349	Step III 044 Conveyor Vent	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	350	Step III 044 Conveyor Vent	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	351	Step III 044 Conveyor Vent	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	352	Step III 044 Conveyor Vent	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	353	Step III 044 Conveyor Vent	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	354	Step III 044 Conveyor Vent	2.00 Particulate Point Source	2.10 Material Handling - Pellets
US Steel Minn Ore Operations - Minntac	355	Step III 044 Conveyor Vent	2.00 Particulate Point Source	2.10 Material Handling - Pellets

Preliminary Categorization of BART-Eligible Sources at MN Taconite Plants

STATIONARY SOURCE NAME/LOCATION	EMISSION UNIT ID (2)	EMISSION UNIT DESCRIPTION	Primary Source Type	Secondary Source Type
National Steel Pellet Co.	052	Paint Gun 3	2.00 Particulate Point Source	2.11 Paint Gun
National Steel Pellet Co.	053	Paint Gun 4	2.00 Particulate Point Source	2.11 Paint Gun
National Steel Pellet Co.	054	Paint Gun 5	2.00 Particulate Point Source	2.11 Paint Gun
National Steel Pellet Co.	055	Paint Gun 6	2.00 Particulate Point Source	2.11 Paint Gun
National Steel Pellet Co.	056	Paint Gun 7	2.00 Particulate Point Source	2.11 Paint Gun
National Steel Pellet Co.	024	Cooler Vibrating Feeder - Phase II	2.00 Particulate Point Source	Uncategorized
National Steel Pellet Co.	027	Cooler Vibrating Feeder - Phase I	2.00 Particulate Point Source	Uncategorized
US Steel Minn Ore Operations - Minntac	260	L4 Recoup System Air	2.00 Particulate Point Source	Uncategorized
US Steel Minn Ore Operations - Minntac	281	L5 Recoup Air System	2.00 Particulate Point Source	Uncategorized
US Steel Minn Ore Operations - Minntac	314	L6 Recoup Air System	2.00 Particulate Point Source	Uncategorized
US Steel Minn Ore Operations - Minntac	333	L7 Recoup Air System	2.00 Particulate Point Source	Uncategorized
Northshore Mining Co. - Silver Bay	120	Furnace 11 Discharge	3.00 Induration Point Source	2.06 Straight Grate (Pellet Discharge)
Northshore Mining Co. - Silver Bay	121	Furnace 12 Discharge	3.00 Induration Point Source	2.06 Straight Grate (Pellet Discharge)
National Steel Pellet Co.	019	Grate Kiln - Grate Feed, Phase I	3.00 Induration Point Source	2.07 Grate-Kiln (Grate)
National Steel Pellet Co.	020	Grate Kiln - Grate Feed, Phase II	3.00 Induration Point Source	2.07 Grate-Kiln (Grate)
National Steel Pellet Co.	021	Grate Kiln - Grate Discharge, Phase I	3.00 Induration Point Source	2.07 Grate-Kiln (Grate)
National Steel Pellet Co.	022	Grate Kiln - Grate Discharge, Phase II	3.00 Induration Point Source	2.07 Grate-Kiln (Grate)
US Steel Minn Ore Operations - Minntac	223	L3 Traveling Grate	3.00 Induration Point Source	2.07 Grate-Kiln (Grate)
US Steel Minn Ore Operations - Minntac	259	L4 Traveling Grate	3.00 Induration Point Source	2.07 Grate-Kiln (Grate)
US Steel Minn Ore Operations - Minntac	280	L5 Traveling Grate	3.00 Induration Point Source	2.07 Grate-Kiln (Grate)
US Steel Minn Ore Operations - Minntac	313	L6 Traveling Grate	3.00 Induration Point Source	2.07 Grate-Kiln (Grate)
US Steel Minn Ore Operations - Minntac	332	L7 Traveling Grate	3.00 Induration Point Source	2.07 Grate-Kiln (Grate)
EVTAC Mining - Plant	039	Line 1 Kiln Cooler Discharge	3.00 Induration Point Source	2.09 Grate-Kiln (Pellet Discharge)
Hibbing Taconite Co	020	Pellet Indurating Furnace Line No 1	3.00 Induration Point Source	3.01 Straight Grate (Induration)
Hibbing Taconite Co	021	Pellet Indurating Furnace Line No 2	3.00 Induration Point Source	3.01 Straight Grate (Induration)
Hibbing Taconite Co	022	Pellet Indurating Furnace Line No 3	3.00 Induration Point Source	3.01 Straight Grate (Induration)
Ispat Inland Mining Co.	026	Indurating Machine	3.00 Induration Point Source	3.01 Straight Grate (Induration)
Northshore Mining Co. - Silver Bay	100	Furnace 11 Hood Exhaust	3.00 Induration Point Source	3.01 Straight Grate (Induration)
Northshore Mining Co. - Silver Bay	104	Furnace 12 Hood Exhaust	3.00 Induration Point Source	3.01 Straight Grate (Induration)
EVTAC Mining - Plant	040	Line 1 Pellet Induration	3.00 Induration Point Source	3.02 Grate-Kiln (Induration)
EVTAC Mining - Plant	042	Line 2 Pellet Induration	3.00 Induration Point Source	3.02 Grate-Kiln (Induration)
National Steel Pellet Co.	029	Grate Kiln - Indurator Waste Gas, Phase I	3.00 Induration Point Source	3.02 Grate-Kiln (Induration)
National Steel Pellet Co.	030	Grate Kiln - Indurator Waste Gas, Phase II	3.00 Induration Point Source	3.02 Grate-Kiln (Induration)
National Steel Pellet Co.	031	Grate Kiln - Indurator Waste Gas, Phase II	3.00 Induration Point Source	3.02 Grate-Kiln (Induration)
US Steel Minn Ore Operations - Minntac	225	L3 Rotary Kiln	3.00 Induration Point Source	3.02 Grate-Kiln (Induration)
US Steel Minn Ore Operations - Minntac	261	L4 Rotary Kiln	3.00 Induration Point Source	3.02 Grate-Kiln (Induration)
US Steel Minn Ore Operations - Minntac	282	L5 Rotary Kiln	3.00 Induration Point Source	3.02 Grate-Kiln (Induration)
US Steel Minn Ore Operations - Minntac	315	L6 Rotary Kiln	3.00 Induration Point Source	3.02 Grate-Kiln (Induration)
US Steel Minn Ore Operations - Minntac	334	L7 Rotary Kiln	3.00 Induration Point Source	3.02 Grate-Kiln (Induration)
Northshore Mining Co. - Silver Bay	002	Power Boiler 2	4.00 External Combustion Source	4.01 Boiler (Electrical Generator)
EVTAC Mining - Mine	008	Boiler 11 (South Crusher Bldg)	4.00 External Combustion Source	4.02 Boiler
EVTAC Mining - Mine	009	Boiler 4 (North Crusher Bldg)	4.00 External Combustion Source	4.02 Boiler
EVTAC Mining - Mine	011	Boiler 2 (North Maint. Bldg)	4.00 External Combustion Source	4.02 Boiler
EVTAC Mining - Mine	012	Boiler 3 (North Maint. Bldg)	4.00 External Combustion Source	4.02 Boiler
EVTAC Mining - Mine	013	Boiler 12 (South Crusher Bldg)	4.00 External Combustion Source	4.02 Boiler
EVTAC Mining - Plant	051	Fairlane Truck Shop Boiler	4.00 External Combustion Source	4.02 Boiler
EVTAC Mining - Plant	052	Fairlane New Shop Boiler	4.00 External Combustion Source	4.02 Boiler

Preliminary Categorization of BART-Eligible Sources at MN Taconite Plants

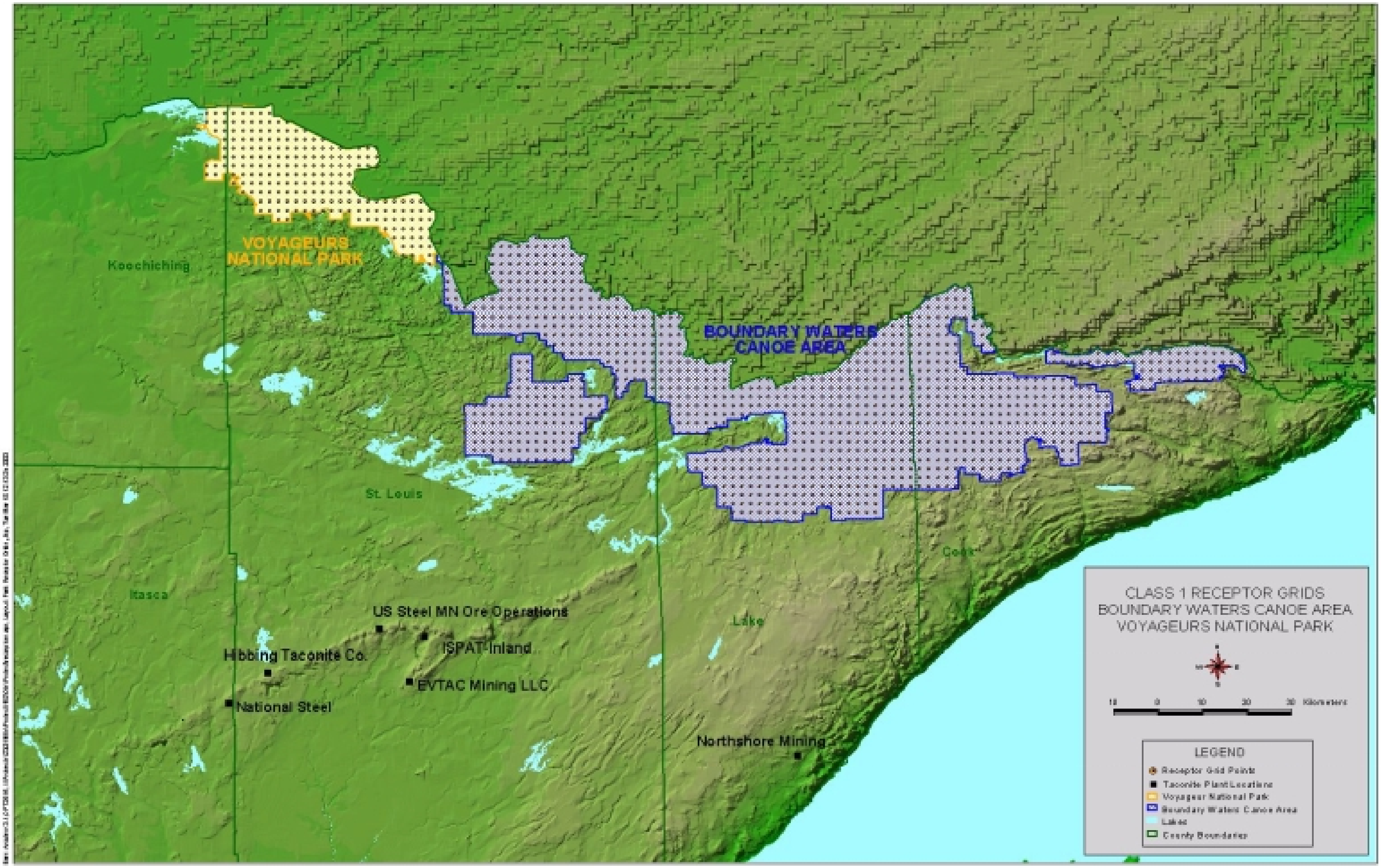
STATIONARY SOURCE NAME/LOCATION	EMISSION UNIT ID (2)	EMISSION UNIT DESCRIPTION	Primary Source Type	Secondary Source Type
EVTAC Mining - Plant	053	Fuel Handling Boiler #1	4.00 External Combustion Source	4.02 Boiler
EVTAC Mining - Plant	054	Fuel Handling Boiler #2	4.00 External Combustion Source	4.02 Boiler
Ispat Inland Mining Co.	003	Unit #3 Boiler	4.00 External Combustion Source	4.02 Boiler
Northshore Mining Co. - Silver Bay	003	Process Boiler 1	4.00 External Combustion Source	4.02 Boiler
Northshore Mining Co. - Silver Bay	004	Process Boiler 2	4.00 External Combustion Source	4.02 Boiler
US Steel Minn Ore Operations - Minntac	001	SI 104 MMBtu Heating Boiler	4.00 External Combustion Source	4.02 Boiler
US Steel Minn Ore Operations - Minntac	002	SI 104 MMBtu Heating Boiler	4.00 External Combustion Source	4.02 Boiler
US Steel Minn Ore Operations - Minntac	003	SII 125 MMBtu Heating Boiler	4.00 External Combustion Source	4.02 Boiler
US Steel Minn Ore Operations - Minntac	004	SIII 153 MMBtu Heating Boiler	4.00 External Combustion Source	4.02 Boiler
US Steel Minn Ore Operations - Minntac	005	SIII 153 MMBtu Heating Boiler	4.00 External Combustion Source	4.02 Boiler
US Steel Minn Ore Operations - Minntac	010	24.60 MMBtu Boiler	4.00 External Combustion Source	4.02 Boiler
US Steel Minn Ore Operations - Minntac	011	24.60 MMBtu Boiler	4.00 External Combustion Source	4.02 Boiler
EVTAC Mining - Plant	099	10 Makeup Heaters (F. Crusher Bldg)	4.00 External Combustion Source	4.03 Heater (Make-up)
US Steel Minn Ore Operations - Minntac	028	Zinc Melt Furnace	4.00 External Combustion Source	4.04 Zinc Melt Furnace
US Steel Minn Ore Operations - Minntac	029	Zinc Melt Furnace	4.00 External Combustion Source	4.04 Zinc Melt Furnace
US Steel Minn Ore Operations - Minntac	030	Zinc Melt Furnace	4.00 External Combustion Source	4.04 Zinc Melt Furnace
US Steel Minn Ore Operations - Minntac	031	Zinc Melt Furnace	4.00 External Combustion Source	4.04 Zinc Melt Furnace
US Steel Minn Ore Operations - Minntac	032	Zinc Melt Furnace	4.00 External Combustion Source	4.04 Zinc Melt Furnace
US Steel Minn Ore Operations - Minntac	033	Zinc Melt Furnace	4.00 External Combustion Source	4.04 Zinc Melt Furnace
US Steel Minn Ore Operations - Minntac	142	Zinc Melt Furnace	4.00 External Combustion Source	4.04 Zinc Melt Furnace
US Steel Minn Ore Operations - Minntac	143	Zinc Melt Furnace	4.00 External Combustion Source	4.04 Zinc Melt Furnace
US Steel Minn Ore Operations - Minntac	006	Diesel Generator	5.00 Internal Combustion Source	5.01 Diesel Engine
US Steel Minn Ore Operations - Minntac	007	Diesel Generator	5.00 Internal Combustion Source	5.01 Diesel Engine
US Steel Minn Ore Operations - Minntac	008	Diesel Generator	5.00 Internal Combustion Source	5.01 Diesel Engine
US Steel Minn Ore Operations - Minntac	009	Diesel Fire Pump	5.00 Internal Combustion Source	5.01 Diesel Engine
US Steel Minn Ore Operations - Minntac	012	Diesel Generator	5.00 Internal Combustion Source	5.01 Diesel Engine
US Steel Minn Ore Operations - Minntac	051	Diesel Generator	5.00 Internal Combustion Source	5.01 Diesel Engine
US Steel Minn Ore Operations - Minntac	215	Diesel Generator	5.00 Internal Combustion Source	5.01 Diesel Engine
US Steel Minn Ore Operations - Minntac	383	Diesel Generator	5.00 Internal Combustion Source	5.01 Diesel Engine
US Steel Minn Ore Operations - Minntac	384	Diesel Generator	5.00 Internal Combustion Source	5.01 Diesel Engine
US Steel Minn Ore Operations - Minntac	385	Diesel Generator	5.00 Internal Combustion Source	5.01 Diesel Engine
US Steel Minn Ore Operations - Minntac	386	Diesel Generator	5.00 Internal Combustion Source	5.01 Diesel Engine
US Steel Minn Ore Operations - Minntac	387	Air Compressor	5.00 Internal Combustion Source	Uncategorized

Preliminary Categorization of BART-Eligible Sources at MN Taconite Plants

STATIONARY SOURCE NAME/LOCATION	EMISSION UNIT ID (2)	EMISSION UNIT DESCRIPTION	Primary Source Type	Secondary Source Type

(2) NEI ID. If you use an ID other than NEI, please specify.

Primary Source Type	Secondary Source Type
1.00 Particulate Fugitive Source	1.01 Unpaved Roads
	1.02 Material Handling (Conveyor)
	1.03 Material Handling (Mobile Equipment)
	1.04 Material Handling (Other)
	1.03 Wind Erosion (Stockpile)
	1.04 Wind Erosion (Other)
2.00 Particulate Point Source	2.01 Crushing
	2.02 Material Handling - Ore
	2.03 Material Handling - Additive
	2.04 Material Handling - Coal
	2.05 Straight Grate (Grate)
	2.06 Straight Grate (Pellet Discharge)
	2.07 Grate-Kiln (Grate)
	2.08 Grate-Kiln (Cooler)
	2.09 Grate-Kiln (Pellet Discharge)
	2.10 Material Handling - Pellets
	2.11 Paint Gun
3.00 Induration Point Source	3.01 Straight Grate (Induration)
	3.02 Grate-Kiln (Induration)
4.00 External Combustion Source	4.01 Boiler (Electrical Generator)
	4.02 Boiler
	4.03 Heater (Make-up)
	4.04 Zinc Melt Furnace
5.00 Internal Combustion Source	5.01 Diesel Engine
Uncategorized	Uncategorized


VOYAGEURS
NATIONAL PARK
Koochiching
BOUNDARY WATERS
CANOE AREA
St. Louis
Cook
Itasca
Lake
US Steel MN Ore Operations
ISPAT-Inland
Hibbing Taconite Co.
EVTAC Mining LLC
National Steel
Northshore Mining
CLASS 1 RECEPTOR GRIDS
BOUNDARY WATERS CANOE AREA
VOYAGEURS NATIONAL PARK
10
0
10
20
30
Kilometers
LEGEND
Receptor Grid Points
Taconite Plant Locations
Voyageur National Park
Boundary Waters Canoe Area
Lakes
County Boundaries

TACONITE BART ASSISTANCE TO MPCA
AFFORDABILITY OF CONTROLS
March 18, 2003

1. **Prepare summary of the general industry financial condition and foreign competition**

   - Use documented publicly available information

   - Consider other topics identified by industry and that industry will provide supporting data/information to summarize

   Objective: provide qualitative analysis of the ramifications of cost increases to the industry

2. **Develop a cost table for taconite producer and MPCA use in the future**

   - BART alternative capital costs (annualized cost)
   - Increase in compliance demonstration costs due to BART alternative
   - Pass through costs (power, diesel fuel cost increases due to BART)
   - Sum total cost and production cost increase for an individual BART alternative
   - Develop $/ton cost increase due to BART alternative

   Objective: provide for the documentation of cost increases to industry for each BART alternative evaluated

3. **Summarize potential power and diesel fuel cost increases due to BART for taconite producer and MPCA use in the future**

   - Interview primary power and diesel fuel providers regarding BART alternatives considered for them, product cost increases, and ability to increase product costs

   Objective: first cut evaluation of "pass through costs" for future update by industry and MPCA

ATTACHMENT D

July 1, 1999, Federal Register Notice – Regional Haze Regulations; Final Rule

Thursday
July 1, 1999

Part II

Environmental Protection Agency

40 CFR Part 51
Regional Haze Regulations; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 51

[FRL–6353–4]

RIN 2060–AF32

[Docket No A–95–38]

Regional Haze Regulations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Section 169A of the Clean Air Act (CAA) sets forth a national goal for visibility which is the ''prevention of any future, and the remedying of any existing, impairment of visibility in Class I areas which impairment results from manmade air pollution.'' There are 156 Class I areas across the country, including many well-known national parks and wilderness areas, such as the Grand Canyon, Great Smokies, Shenandoah, Yellowstone, Yosemite, the Everglades, and the Boundary Waters. Regional haze is visibility impairment caused by the cumulative air pollutant emissions from numerous sources over a wide geographic area. The EPA promulgated regulations in 1980 to address visibility impairment that is ''reasonably attributable'' to one or a small group of sources, but EPA deferred action on regional haze regulations until monitoring, modeling, and scientific knowledge about the relationship between pollutants and visibility effects improved. In 1993, the National Academy of Sciences (NAS) concluded that ''current scientific knowledge is adequate and control technologies are available for taking regulatory action to improve and protect visibility.''

On July 31, 1997 (62 FR 41138), EPA published proposed amendments to the 1980 regulations to set forth a program to address regional haze visibility impairment. The EPA also published a notice of availability of additional information on the proposed regional haze regulation on September 3, 1998. This notice took comment specifically on new implementation plan timelines set forth in the Transportation Equity Act for the 21st Century, Public Law 105–178, and on a proposal from the Western Governors' Association (WGA) for addressing the recommendations of the Grand Canyon Visibility Transport Commission (GCVTC) in the final rule. The EPA received more than 1300 comments overall on the proposal and notice of availability.

Today's final rule calls for States to establish goals and emission reduction strategies for improving visibility in all 156 mandatory Class I national parks and wilderness areas. Specific provisions are included in the rule allowing nine western States to implement the recommendations of the GCVTC within the framework of the national regional haze program. In addition, EPA encourages States to work together in regional partnerships to develop and implement multistate strategies to reduce emissions of visibility-impairing fine particle pollution.

DATES: The regulatory amendments announced herein take effect on August 30, 1999.

ADDRESSES: *Docket.* The public docket for this action is available for public inspection and copying between 8:00 a.m. and 5:30 p.m., Monday through Friday excluding legal holidays, at the Air and Radiation Docket and Information Center (6102), Attention: Docket A–95–38, Room M–1500, 401 M Street, SW, Washington, DC 20460, phone 202–260–7548, fax 202–260–4400, email: A-and-R-Docket@epamail.epa.gov. A reasonable fee for copying may be charged. The regional haze regulations are subject to the rulemaking procedures under section 307(d) of the CAA. The documents relied on to develop the regional haze regulations have been placed in the docket.

FOR FURTHER INFORMATION CONTACT: For general questions regarding this notice, contact Richard Damberg, U.S. EPA, MD–15, Research Triangle Park, NC 27711, telephone (919) 541–5592, email: damberg.rich@epa.gov.

SUPPLEMENTARY INFORMATION:

Electronic Availability

The official record for this rulemaking, as well as the public version, has been established under docket number A–95–38 (including comments and data submitted electronically as described below). A public version of this record, including printed, paper versions of electronic comments, which does not include any information claimed as Confidential Business Information, is available for inspection from 8:00 a.m. to 5:30 p.m., Monday through Friday, excluding legal holidays. The official rulemaking record is located at the address in **ADDRESSES** at the beginning of this document. World Wide Web sites have been developed for overview information on visibility issues and related programs. These web sites can be accessed from Uniform Resource Locator (URL): http://www.epa.gov/airlinks/.

Table of Contents

I. Overview of Today's Final Rule

This preamble provides the details and rationale for the final regional haze rule. Unit II includes background information on regional haze and on the legal and scientific basis for today's action. Unit III describes the provisions of the national requirements for regional haze and includes a discussion of the comments received on the July 1997 proposal. Unit IV discusses specific regional provisions for 16 western Class I areas that were the subject of a 1996 report by the GCVTC. Unit V is a discussion of issues related to implementation of the rule by Indian tribes. Unit VI summarizes several technical amendments to existing visibility regulations in order to coordinate those requirements with the requirements of today's final rule. Unit VII discusses how today's final rulemaking is in compliance with the requirements of various executive orders and statutes.

II. Background Information on the Regional Haze Program

A. Regional Haze

Regional haze is visibility impairment that is produced by a multitude of sources and activities which emit fine particles and their precursors and which are located across a broad geographic area.[1] Twenty years ago, when initially adopting the visibility protection provisions of the CAA, Congress specifically recognized that the ''visibility problem is caused primarily by emission into the atmosphere of SO_2, oxides of nitrogen, and particulate matter, especially fine particulate matter, from inadequate[ly] controlled sources.''[2] The fine particulate matter (PM) (e.g., sulfates, nitrates, organic carbon, elemental carbon, and soil dust) that impairs visibility by scattering and absorbing light can cause serious health effects and mortality in humans, and contribute to environmental effects such as acid deposition and eutrophication. Data from the existing visibility monitoring network show that visibility impairment caused by air pollution occurs virtually all the time at most national park and wilderness area monitoring stations.[3] Average visual range in many Class I areas[4] in the Western United States is 100–150 kilometers (13.6–9.6 deciviews),[5] or about one-half to two-thirds of the visual range that would exist without manmade air pollution. In most of the east, the average visual range is less than 30 kilometers (25 deciviews or more), or about one-fifth of the visual range that would exist under estimated natural conditions. The role of regional transport of fine particles in contributing to elevated PM levels and regional haze impairment has been well documented by many researchers[6] and recognized as a significant issue by policymakers from Federal, State and local agencies, industry and environmental organizations.

B. How Today's Final Rule Responds to the CAA

The visibility protection program under sections 169A, 169B, and 110(a)(2)(J) of the CAA is designed to protect Class I areas[7] from impairment due to manmade air pollution. Congress adopted the visibility provisions in the CAA to protect visibility in these ''areas of great scenic importance.''[8] The current regulatory program addresses visibility impairment in these areas that is ''reasonably attributable''[9] to a specific source or small group of sources. In adopting section 169A, the core visibility provisions adopted in the 1977 CAA Amendments, Congress also expressed its concern with visibility problems caused by pollutants that ''emanate from a variety of sources.'' It noted the problem of ''hazes'' from ''regionally distributed sources,''[10] and concluded that additional provisions were needed to remedy ''the growing visibility problem.'' The purpose of today's final rule is to revise the existing visibility regulations[11] in order to integrate provisions addressing regional haze impairment. Today's final rule establishes a comprehensive visibility protection program for Class I areas. Figure 1 is a map indicating the locations of the Class I areas.

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[1] U.S. EPA. Air Quality Criteria for Particulate Matter. Office of Research and Development, National Center for Environmental Assessment. EPA/600/P–95/001bF. Research Triangle Park, NC. 1996.

[2] H.R. Rep. No. 95–294 at 204 (1977).

[3] National Park Service. Air Quality in the National Parks: A Summary of Findings from the National Park Service Air Quality Research and Monitoring Program. Natural Resources Report 88–1. Denver, CO, July 1988.

[4] Areas designated as mandatory Class I Federal areas are those national parks exceeding 6000 acres, wilderness areas and national memorial parks exceeding 5000 areas, and all international parks which were in existence on August 7, 1977. Visibility has been identified as an important value in 156 of these areas. See 40 CFR part 81, subpart D. The extent of a Class I area includes subsequent changes in boundaries, such as park expansions. (CAA section 162(a)). States and tribes may designate additional areas as Class I, but the requirements of the visibility program under section 169A of the CAA apply only to ''mandatory Class I Federal areas,'' and they do not directly address any additional areas.

[5] ''Deciview'' is a visibility metric discussed further in unit III.C. of today's notice, and defined in section 51.301(bb) of the rule. Higher deciview values indicate greater levels of visibility impairment.

[6] See National Acid Precipitation Assessment Program. Acid Deposition: State of Science and Technology. Report 24, Visibility: Existing and Historical Conditions—Causes and Effects, Table 24–6. Washington, DC 1991. See also U.S. EPA. Air Quality Criteria for Particulate Matter. Office of Research and Development, National Center for Environmental Assessment. EPA/600/P–95/001bF. Research Triangle Park, NC. 1996.

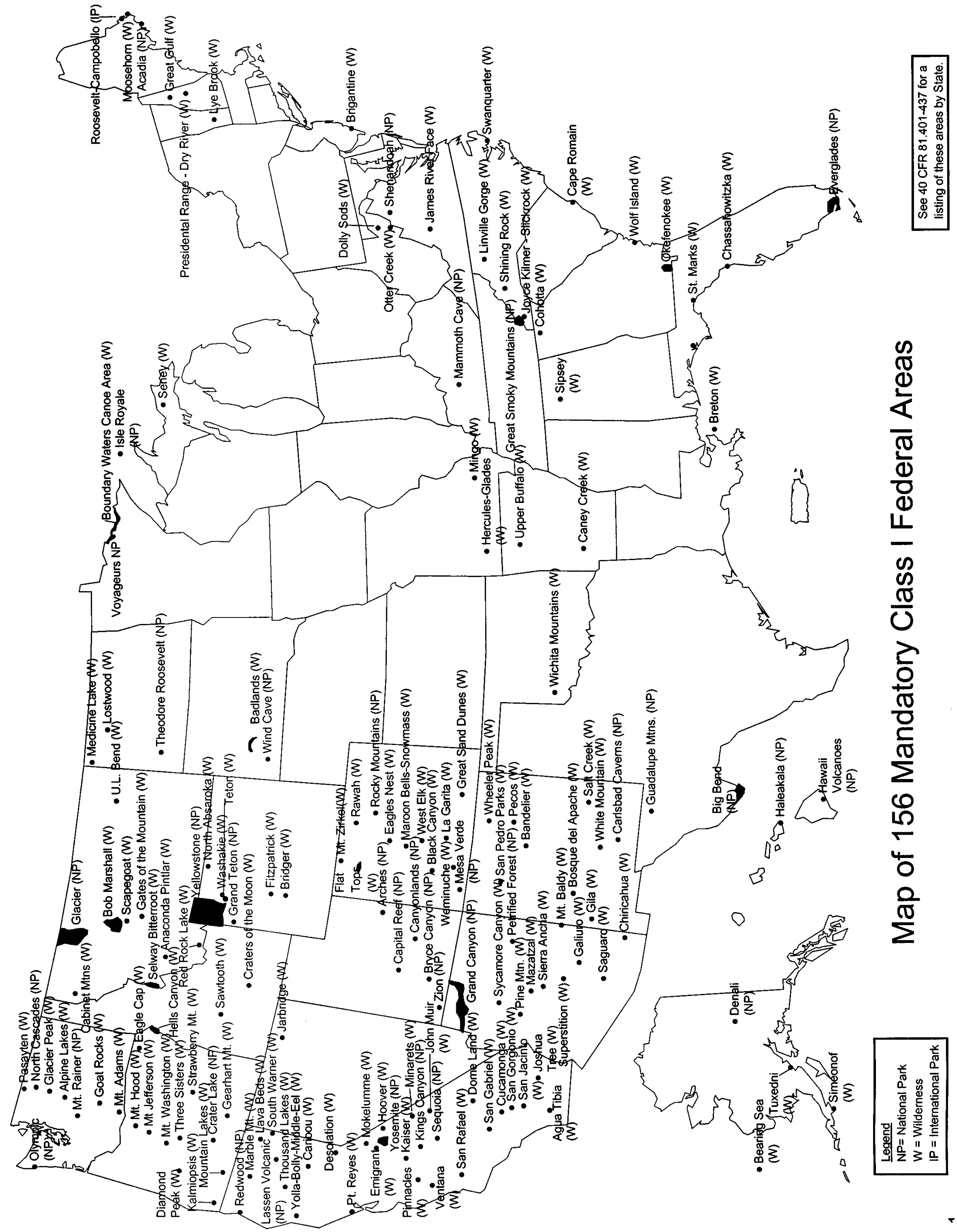
[7] For the purposes of this preamble, the term ''Class I area'' will be used to describe the 156 mandatory Class I Federal areas identified in section 51.301(o) and in part 81, subpart D of this title.

[8] H.R. Rep. No. 294, 95th Cong. 1st Sess. at 205 (1977).

[9] ''Reasonably attributable'' visibility impairment, as defined in section 51.301(s), means ''attributable by visual observation or any other technique the State deems appropriate.'' It includes impacts to Class I areas caused by plumes or layered hazes from a single source or small group of sources.

[10] H.R. Rep. No. 95–294 at 204 (1977).

[11] 45 FR 80084 (December 2, 1980) and section 51.300–307.



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C. The 1980 Visibility Regulation—Commitment to a Regional Haze Program

Section 169A of the CAA, established in the 1977 Amendments, sets forth a national visibility goal that calls for ''the prevention of any future, and the remedying of any existing, impairment of visibility in Class I areas which impairment results from manmade air pollution.'' The EPA's initial visibility regulations, developed in 1980, address visibility impairment that is ''reasonably attributable'' to a single source or small group of sources. Under the 1980 rules, the 35 States and 1 territory containing Class I areas [12] are required to:

(1) Revise their SIPs to assure reasonable progress toward the national visibility goal;

(2) Determine which existing stationary facilities should install the best available retrofit technology (BART) for controlling pollutants which impair visibility;

(3) Develop, adopt, implement, and evaluate long-term strategies for making reasonable progress toward remedying any existing and preventing any future impairment in the Class I areas;

(4) Adopt certain measures to assess potential visibility impacts due to new or modified major stationary sources, including measures to notify Federal land managers (FLMs) of proposed new source permit applications, and to consider visibility analyses conducted by FLMs in their new source permitting decisions; and

(5) Conduct visibility monitoring in Class I areas.

The 1980 rules addressing ''reasonably attributable'' visibility impairment were designed to be the first phase in EPA's overall program to protect visibility. The EPA explicitly deferred national rules addressing regional haze impairment until some future date:

> * * * when improvement in monitoring techniques provides more data on source-specific levels of visibility impairment, regional scale models become refined, and our scientific knowledge about the relationships between emitted air pollutants and visibility impairment improves.[13]

The EPA believes that the technical tools and our scientific understanding of visibility impairment are now sufficiently refined to move forward with a national program addressing regional haze in Class I areas. The EPA's position is supported by the NAS 1993 report, Protecting Visibility in National Parks and Wilderness Areas. One of the principal conclusions of this report is that ''current scientific knowledge is adequate and control technologies are available for taking regulatory action to improve and protect visibility.'' [14] Section II.D. describes a number of other studies and information now available which provide the technical basis to move forward with a regional haze program.

In addition, EPA finds the visibility protection provisions of the CAA to be quite broad. Although EPA is addressing visibility protection in phases, the national visibility goal in section 169A calls for addressing visibility impairment generally, including regional haze.[15]

Further, Congress added section 169B as part of the 1990 Amendments to the CAA to focus attention on regional haze issues; it calls for EPA to issue regional haze rules within 18 months of receipt of the final report from the GCVTC. In addition, section 169B includes provisions for EPA to conduct visibility research with the National Park Service and other Federal agencies, to develop an interim findings report on the visibility research,[16] to develop a Report to Congress on expected visibility improvements due to implementation of other air pollution programs,[17] and to provide periodic reports to Congress on trends in visibility improvements. Section 169B also provides the authority to the Administrator to establish visibility transport commissions in response to a petition from two or more States, or on her and/or his own motion. To date, EPA has not received any petitions from groups of States requesting formation of a visibility transport commission.

Section 169B(f) called for EPA to establish a visibility transport commission for the region affecting visibility of the Grand Canyon National Park. The purpose of this commission was to assess scientific and technical information pertaining to adverse impacts on visibility at the Park from existing emissions and projected growth in emissions. The statute specifically called for a report to EPA recommending measures to remedy such impacts and to address long-term strategies for addressing regional haze.[18] In 1991, EPA established the GCVTC,[19] and the GCVTC issued its final report in June 1996.[20] The recommendations of the GCVTC and their incorporation as potential SIP requirements into the final rule, are discussed in greater detail in unit IV of the preamble.

Finally, section 169B(e) calls for the Administrator to consider past research and the recommendations of visibility transport commissions in carrying out the ''regulatory responsibilities under section 169A, including criteria for measuring 'reasonable progress' toward the national goal.'' [21] The EPA is required by the CAA to meet these regulatory responsibilities within 18 months of receiving the GCVTC report. Today's final rule fulfills EPA's responsibility under section 169A, pending since 1980, to put in place a national regulatory program that addresses both reasonably attributable and regional haze visibility impairment. Today's action is also EPA's response to the GCVTC report as anticipated by section 169B.

D. Sources of Scientific Information and Policy Recommendations on Regional Haze

In developing today's revisions to the visibility regulations, EPA has taken into account a significant body of scientific information and policy recommendations on visibility issues that have been developed over more than 20 years. This unit highlights key sources of information upon which the final regional haze rule is based.

For many years, visibility impairment has been considered the ''best understood and most easily measured

[12] The States and one territory having at least one Class I area are listed in section 51.300(b)(2). These States and one territory are as follows: Alabama, Alaska, Arizona, Arkansas, California, Colorado, Florida, Georgia, Hawaii, Idaho, Kentucky, Louisiana, Maine, Michigan, Minnesota, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, North Carolina, North Dakota, Oklahoma, Oregon, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Virgin Islands, Washington, West Virginia, and Wyoming. For a specific list of Class I areas located in each state or territory, see 40 CFR 81.401–437.

[13] 45 FR 80086.

[14] National Research Council Committee on Haze in National Parks and Wilderness Areas, Protecting Visibility in National Parks and Wilderness Areas, National Academy Press, 1993, p. 11.

[15] *State of Maine* v. *Thomas*, 874 F.2d 883, 885 (1st Cir. 1989) (''EPA's mandate to control the vexing problem of regional haze emanates directly from the CAA, which 'declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in Class I areas which impairment results from manmade air pollution.' '') (citation omitted).

[16] U.S. EPA, Interim Findings on the Status of Visibility Research, Office of Research and Development, EPA/600/R–95/021, February 1995. See also 60 FR 8659 notice announcing the report availability and how to obtain copies (Feb. 15, 1995.

[17] U.S. EPA, Effects of the 1990 CAA Amendments on Visibility in Class I Areas: An EPA Report to Congress, October 1993 (EPA–452/R–93–014).

[18] CAA section 169B(d)(2)(C).

[19] 56 FR 57522, November 12, 1991.

[20] Grand Canyon Visibility Transport Commission, Recommendations for Improving Western Vistas, Report to the U.S. EPA, June 10, 1996 (hereafter referred to as ''GCVTC Report'').

[21] CAA section 169B(e)(1).

effect of air pollution.'' [22] Visibility degradation has also been recognized as an indicator of multiple human-health effects and environmental effects resulting from air pollution all over the world.[23] Visibility conditions have been monitored and evaluated for many years, using airport visibility data collected from the 1940's to the present.[24]

In October 1979, EPA published a Report to Congress describing the state of the science on visibility.[25] The report, required under section 169A(a)(3), described available methods for visibility monitoring, modeling, and assessment of strategies to make progress toward the national goal. This report was developed in advance of the 1980 visibility regulations. As noted above, EPA deferred action on regional haze until monitoring techniques, modeling capabilities, and the understanding of the pollutants affecting visibility were improved. In 1986, the IMPROVE (Interagency Monitoring of Protected Visual Environments) visibility monitoring program was initiated in 30 Class I areas. The IMPROVE program has been coordinated through a cooperative, multiagency approach with participation by EPA, the FLMs, and States. Through the IMPROVE program, significant progress has been made in understanding the effect of various pollutants on current visibility conditions and trends, in developing well-accepted monitoring protocols, and in developing a sound approach for calculating light extinction values from aerosol and humidity data. The IMPROVE program has issued two major reviews of the monitoring data collected to date,[26] and numerous technical papers have been developed using data collected by the network.

In addition, in 1996 EPA began to include a chapter on visibility trends, based on data collected throughout the IMPROVE network, in the National Air Quality and Emissions Trends Report in 1996.[27] Data from 1988 to the present are analyzed for the best 20 percent, middle 20 percent, and worst 20 percent days of the annual distribution, and aggregated for eastern and western sites. Annual summary data are also presented for each individual site in an appendix.

Visibility research continued throughout the 1980's and is documented in many published articles and the proceedings of three major visibility conferences.[28] In addition, the NAPAP completed a comprehensive review of the state of the science of visibility in 1991.[29] This peer-reviewed report reached a number of important conclusions, including: (1) Light scattering is dominated by fine particles; (2) sulfates are the dominant source of light extinction in the east, and one of several major sources of extinction in the west; (3) rural visibility varies significantly between the east and west; (4) average natural visibility conditions are 150 kilometers visual range (9.6 deciviews) in the east and 230 kilometers visual range (5.3 deciviews) in the west; and (5) haze trends in the eastern United States have been dominated by sulfur emission trends since the late 1940's.

The NAS formed a Committee on Haze in National Parks and Wilderness Areas in 1990 to address a number of regional haze-related issues, including methods for determining anthropogenic source contributions to haze and methods for considering alternative source control measures. The 1993 report by this Committee contributed significantly to the state of the science regarding regional haze visibility impairment.[30] The Committee issued several important conclusions in the report, including: (1) Current scientific knowledge is adequate and control technologies are available for taking regulatory action to address regional haze; (2) progress toward the national goal will require regional programs that operate over large geographic areas and limit emissions of pollutants that can cause regional haze; (3) a program to address regional haze visibility impairment that focuses solely on determining the contributions of individual emission sources to such visibility impairment is likely to fail, and instead, strategies should be adopted to consider simultaneously the effect of many sources on a regional basis; (4) visibility impairment can be attributed to emission sources on a regional scale through the use of several kinds of models; (5) visibility and control policies might need to be different in the west than the east; (6) efforts to improve visibility within Class I areas will benefit visibility outside these areas and could help alleviate other types of air quality problems as well; (7) achieving the national visibility goal will require a substantial, long-term program; and (8) continued progress toward this goal will require a greater commitment toward atmospheric research, monitoring, and emissions control research and development.

Also in 1993, EPA developed its Report to Congress on the projected effects on visibility in Class I areas due to implementation of the 1990 CAA Amendments. [31] The report concluded that conditions on the worst visibility days are expected to improve by approximately 3 deciviews by 2010 across the most impaired portions of the Eastern United States. Most of this improvement is expected in the 1995–2005 timeframe due to sulfur dioxide reductions under the acid rain program. In the Southwestern United States, the visibility change was predicted to be less than 1 deciview in most Class I areas except San Gorgonio Wilderness (which is located downwind of Los Angeles), for which a 1–2 deciview improvement is expected.

[22] Council on Environmental Quality, Visibility Protection for Class I Areas: The Technical Basis, Washington, DC, 1978.

[23] National Research Council, NAS Committee on Haze in National Parks and Wilderness Areas, Protecting Visibility in National Parks and Wilderness Areas, National Academy Press, 1993, p. 23.

[24] National Acid Precipitation Assessment Program (NAPAP), Acid Deposition: State of Science and Technology. Report 24, Visibility: Existing and Historical Conditions—Causes and Effects, Washington, DC, 1991.

[25] U.S. EPA, Protecting Visibility: An EPA Report to Congress; Office of Air Quality Planning and Standards, EPA–450/5–79–008, October 1979.

[26] Sisler, J. et al., Spatial and Seasonal Patters and Long-Term Variability of the Chemical Composition of the Haze in the U.S.: An Analysis of Data from the IMPROVE Network, Fort Collins, CO, Cooperative Institute for Research in the Atmosphere, Colorado State University, 1996. See also Sisler, J., et al., Spatial and Temporal Patters and the Chemical Composition of the Haze in the United States: An Analysis of Data From the IMPROVE Network, 1988–1991, Fort Callins, CO, 1993.

[27] U.S. EPA, National Air Quality and Emissions Trends Report, 1996, Office of Air Quality Planning and Standards, EPA 454/R–97–013, January 1998. See also U.S. EPA, National Air Quality and Emissions Trends Report, 1997, Office of Air Quality Planning and Standards, EPA 454/R–98–016, January 1999.

[28] Atmospheric Environment, Proceedings of EPA Symposium on Plumes and Visibility—Measurements and Model Components, November 1980, Atmos. Environ., 15:1785–2646. See also Bhardwaja, P.J., ed., Visibility Protection: Research and Policy Aspects. Transactions of APCA Specialty Conference, September 1986, Grand Tetons National Park, WY. Air Pollution Control Assoc., Pittsburgh, PA, 1987. See also Mathai, C.V., ed., Visibility and Fine Particles. Transactions of AWMA specialty conference, October 1989, Estes Park, CO. Air and Waste Management Assoc., Pittsburgh, PA, 1990.

[29] National Acid Precipitation Assessment Program (NAPAP), Acid Deposition: State of Science and Technology, Report 24, Visibility: Existing and Historical Conditions—Causes and Effects, Washington, DC, 1991.

[30] National Research Council, NAS Committee on Haze in National Parks and Wilderness Areas, Protecting Visibility in National Parks and Wilderness Areas, National Academy Press, Washington, DC, 1993.

[31] U.S. EPA, Effects of the 1990 Clean Air Act Amendments on Visibility in Class I Areas: An EPA Report to Congress, Office of Air Quality Planning and Standards, EPA–452/R–93–014, October 1993.

As required by section 169B(a)(2) of the CAA, EPA issued a report in 1995 on interim findings on the status of visibility research completed since 1990.[32] This report reviewed four major visibility related reports published since 1990,[33] provided citations of published research papers, and summarized research under way by the GCVTC, four Federal agencies, and the Electric Power Research Institute. As noted above, the GCVTC issued a report in June 1996 containing recommendations for protecting visibility at 16 Class I areas on the Colorado Plateau. Based on EPA's discretionary authority under section 169B(c), it expanded the scope of the GCVTC:

* * * to include additional Class I areas in the vicinity of the Grand Canyon National Park—-what is sometimes referred to as the ''Golden Circle'' of parks and wilderness areas. This includes most of the national parks and national wilderness areas of the Colorado Plateau.[34]

The GCVTC was charged with assessing information about visibility impacts in the region and making policy recommendations to EPA to address such impacts. The CAA called for the GCVTC to assess studies conducted under section 169B as well as other available information ''pertaining to adverse impacts on visibility from potential or projected growth in emissions for sources located in the * * * Region,'' and to issue a report to EPA recommending what measures, if any, should be taken to protect visibility.[35] The CAA specifically provided for the GCVTC's report to address the following measures: (1) The establishment of clean air corridors, in which additional restrictions on increases in emissions may be appropriate to protect visibility in affected Class I areas; (2) the imposition of additional new source review requirements in clean air corridors;[36] and (3) the promulgation of regulations addressing regional haze.

In unit IV of the proposal, EPA discusses the major recommendations of the GCVTC. The GCVTC's recommendations have components that contemplate implementation through a combination of actions by EPA, other Federal agencies, States and tribes in the region, and voluntary measures on the part of public and private entities throughout the region. The GCVTC's recommendations also distinguish between recommended actions and policy or strategy options for consideration. Unit IV addresses how EPA took these recommendations, as well as the body of technical information developed by the GCVTC, into account in developing the final rule.

Response to comments. Some commenters on the regional haze proposal suggested that EPA had not provided an adequate scientific or legal justification for developing a regional haze program. The commenters asserted that the science of regional haze is not understood well enough to develop regulations at this time. In addition, some commenters claimed that EPA has not provided adequate technical guidance for implementation of the rule, and that providing such guidance is a legal prerequisite to promulgating a regional haze rule. The EPA does not agree with these claims.

First, EPA believes it has relied upon a substantial amount of scientific evidence to support development of the regional haze program. Many of the important studies, reports, and other scientific and technical information on which the regional haze rule is based are referenced earlier in this section. In particular, the NAS Committee on Haze in National Parks and Wilderness Areas concluded that ''Current scientific knowledge is adequate and control technologies are available for taking regulatory action to improve and protect visibility.''[37] Thus, EPA believes that its decision to move forward with promulgation of the regional haze program is reasonable, particularly in light of the fact that the Agency's obligation to address regional haze originated more than 20 years ago with passage of the 1977 CAA Amendments.

Second, as discussed in the response to comments, today's final rule provides the States with the necessary guidelines to implement a regional haze program. The EPA believes that the supposition that all technical guidance associated with a program be developed before a rule can be promulgated is unfounded. The EPA recognizes the importance of timely implementation guidance and is committed to providing such guidance, as appropriate, for the regional haze program.

The EPA does not interpret sections 169A and 169B as requiring all technical guidance to be issued by the Agency before the rule is finalized. The EPA is committed to working closely with the States and other interested parties in developing effective guidance documents within a reasonable period of time after promulgation of the final regional haze rule.

E. Relationship to Secondary NAAQS for PM

Today's final rule is an important element in EPA's overall approach to protecting visibility under the CAA. In July 1997, EPA established national secondary ambient air quality standards (NAAQS) for particles with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers ($PM_{2.5}$) as part of its final decision on revision of the existing NAAQS for particulate matter under section 109(d) of the CAA.[38] The secondary standards were based on EPA's determination that the levels selected were ''requisite to protect the public welfare'' against visibility impairment on a nationally uniform basis as provided in section 109(b). Consistent with the purposes of section 169A, however, EPA recognized that such nationally uniform standards would not eliminate all visibility impairment in all parts of the country.[39] The visibility impacts remaining in Class I areas are addressed by today's final rule.

Today's final rule has additional benefits, as EPA expects the regional strategies implemented as part of the regional haze program to improve visibility outside of Class I areas as well. Thus, the regional haze program should contribute to the improvement of local visibility impacts outside of Class I areas that may persist after attainment of the secondary standards.

F. Regional Planning and Integration With Programs to Implement the NAAQS for Ozone and Particulate Matter

The regional haze program is being promulgated in a manner that facilitates integration of emission management strategies for regional haze with the implementation of programs for new NAAQS for ozone and PM. This is being done because of the existing scientific evidence that these air quality problems have common precursor pollutants, emission sources, atmospheric processes, spatial scales for transport, and geographic areas of concern.

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[32] U.S. EPA, Interim Findings on the Status of Visibility Research, Office of Research and Development, EPA/600/R–95/021, February 1995.

[33] These repdorts have already been mentioned in this section: the 1993 NAS report, the 1993 IMPROVE report (Sisler et al.), the 1993 EPA Report to Congress, and the 1991 NAPAP Report to Congress.

[34] 56 FR 57523

[35] CAA Section 169B(d).

[36] A clean air corridor is defined as a region that generally brings clear air to a receptor region, such as the Class I areas of the Golden Circle.

[37] National Research Council, NAS Committee on Haze in National Parks and Wilderness Areas, Protecting Visibility in National Parks and Wilderness Areas, National Academy Press, Washington, DC, 1993, p. 11.

[38] 62 FR 38652 (July 18, 1997).

[39] See section 160(1); H.R. Rep. No. 95–294 at 205 (1977).

Because of the key role of regional pollutant transport in contributing to haze at Class I areas, most of which are in remote locations, the regional haze program recognizes the value of multistate coordination for regional haze program planning and implementation. Consistent with the recommendations of the Clean Air Act Advisory Committee, Subcommittee on Ozone, Particulate Matter, and Regional Haze Implementation Programs,[40] EPA strongly encourages States to undertake multistate regional planning efforts addressing regional haze in a way that coordinates technical analyses and strategy development with the NAAQS to the maximum extent possible. Examples of ongoing coordination among States to address visibility issues include the Western Regional Air Partnership (WRAP) and the Southern Appalachian Mountain Initiative.

The EPA believes that States (and tribes, at their discretion), in partnership with other interested stakeholders, should consider conducting future regional air quality planning efforts to address the implementation of the ozone and PM NAAQS and regional haze program. We encourage States to continue to work together to establish common protocols and approaches for emissions inventory development, emissions tracking, application of regional models, and development of effective emission reduction strategies.

The EPA plans to participate early and actively in regional planning efforts. The EPA recognizes that we must provide early input on issues and to make our views known as issues arise. The EPA has a responsibility to independently review the adequacy of implementation plans in the public rulemaking process and to consider all public comments received on a plan in determining if it meets applicable requirements. However, it is equally important that EPA be open in letting participants know of our views and concerns throughout the process.

The EPA will soon issue final guidance on such regional planning efforts for the purposes of implementing the ozone, particulate matter, and regional haze implementation programs.[41] Also, as a part of EPA's 1999 fiscal year budget, Congress provided $4 million dollars to support regional planning activities. EPA is currently involved with the States in a process to define the appropriate size and composition of regional planning bodies. The final planning guidance will provide a discussion of several important issues related to regional planning efforts. These issues include:

- Taking credit for emissions reductions in other States;
- Important principles for future regional planning efforts;
- The technical assessment process; and
- The strategy development process.

Some important principles discussed in the guidance for conducting regional planning efforts include the following points.

- Regional planning efforts should be a product of State (and, at the discretion of any tribe, tribal) leadership and, thus, should be led by States (and tribes), not EPA. Representatives should have the authority to speak for their organizations.
- States (and tribes at their discretion) should be prepared to make strong, early commitments to implementing the outcome of the regional process to ensure that SIP submittal dates are met.
- Participants in regional planning efforts should set up a work plan to carry out their work. The work plan should contain clearly stated products of the process, dates for completion of those products and mechanisms for funding the needed analyses.
- The technical assessment process should include steps for problem definition, development of emissions inventories, and development of tools to evaluate strategy alternatives.
- In the strategy development process, participants should strive to develop a consensus about (1) the set of regional emissions reductions strategies needed to attain the NAAQS or make ''reasonable progress'' toward the national visibility goal in Class I areas, and (2) the degree to which each State and relevant source category should be required to reduce emissions to implement the recommended strategies.

III. Discussion of National Program Requirements and Response to Comments

- *Scope of Rule—Extending Coverage to All States*

Proposed rule. In the regional haze proposal, EPA proposed to amend section 51.300(b)(3) to extend coverage to all States (excluding certain territories) for the purpose of addressing regional haze visibility impairment. This approach differed from the 1980 visibility regulations for ''reasonably attributable'' impairment, which required the 35 States and the Virgin Islands containing Class I areas to submit SIP revisions and to revise them periodically to assure reasonable progress toward the national visibility goal. Thus, under the proposal, the following additional States and the District of Columbia would be required to submit visibility SIPs: Nebraska, Kansas, Iowa, Wisconsin, Illinois, Indiana, Ohio, Mississippi, New York, Pennsylvania, Massachusetts, Rhode Island, Connecticut, and Maryland. The territories of Puerto Rico, Guam, American Samoa, and the Northern Mariana Islands were not included because their distance from any Class I area significantly exceed the distance that their emissions could be expected to be transported in order to contribute to visibility impairment in any Class I area. However, Hawaii, Alaska, and the Virgin Islands would be subject to the regional haze provisions because of the potential for emissions from sources within their borders to contribute to regional haze impairment in Class I areas also located within their own jurisdiction.

In the proposal, EPA also recommended that all States initially participate in regional planning efforts to more precisely characterize which States are contributing to visibility impairment in other States, as well as the magnitude of such contributions. States could then develop strategies for making reasonable progress in Class I areas throughout the region. The EPA noted that as a result of this process, all States may not have to adopt control strategies. At the same time, EPA cited the 1993 NAS report, which observed that the requirement for a State to revise its implementation plan if it ''may reasonably be anticipated'' to contribute to visibility impairment indicates that Congress intended that ''the philosophy of precautionary action should apply to visibility protection as it applies to other areas [such as the NAAQS].'' Thus, EPA proposed that, at a minimum, all States should be required to develop visibility SIPs in order to ''prevent any future impairment'' as called for by the national goal in section 169A(a)(1).

Contracts received. The EPA received a number of comments on the proposed applicability provisions. Many commenters approved of EPA's approach to require SIPs from all States. Those who did not agree with the scope of the program provided a number of reasons for their opposition. Some commenters recognized the need for a regional haze program, but stated that EPA must first conduct or review

[40] Subcommittee for Ozone, Particulate Matter, and Regional Haze Implementation Programs, Final Report on Subcommittee Discussions, May 1998.

[41] See the November 17, 1998 draft of Implementation Guidance for the Ozone and Particulate Matter NAAQS and Regional Haze Program. EPA's internet site for an electronic version of this guidance: http://www.epa.gov/ttn/oarpg/tlpgm.html.

additional scientific analyses in order to provide justification for requiring additional States to submit visibility SIPs. Other commenters felt that in the proposed applicability provisions, EPA exceeded its statutory authority by extending the regional haze program to States that have not been demonstrated to ''cause or contribute'' to visibility impairment. Some commenters suggested that EPA rely on States with Class I areas to engage nearby States, as appropriate, in regional planning efforts. Some commenters in States containing Class I areas suggested that, for their particular Class I areas, there was no demonstrated visibility problem. They asserted that because visibility levels should already be deemed acceptable, there was no need for a regional haze program in their States. Other commenters felt that EPA should include specific criteria (e.g., distance, emissions, and visibility impact cutoffs) for excluding States or geographic areas from consideration as contributing to regional haze visibility impairment.

Final rule. Consistent with the proposal, EPA has concluded in today's final rule that all States contain sources whose emissions are reasonably anticipated to contribute to regional haze in a Class I area and, therefore, must submit regional haze SIPs. The rationale for this finding is discussed in more detail below.

In making this finding, EPA considered three factors: (1) The specific statutory language in the CAA; (2) the weight of evidence demonstrating long-range transport of fine particulate pollution that affects visibility in Class I areas; and (3) current monitored conditions in Class I areas across the country. The EPA's consideration of each of these factors is discussed below.

Two key provisions in section 169A support EPA's finding that all States must develop SIPs for regional haze. Section 169A(b)(2) requires EPA to promulgate regulations to require SIPs from those States where the emissions ''may reasonably be anticipated to cause or contribute to any impairment of visibility'' in a mandatory Class I Federal area. The EPA believes that this provision does not require the Agency to provide absolute certainty regarding the effect of emissions from the State on visibility in a particular Class I area.

The Ninth Circuit has interpreted the language, ''may reasonably be anticipated to cause or contribute to any impairment of visibility,'' in a case involving identical language in section 169A(b)(2)(A) relating to BART.[42] The EPA believes that the court's interpretation of this phrase may be appropriately used in regard to program applicability as well. In its decision, the court found that the language ''may reasonably be anticipated to cause or contribute'' establishes an ''extremely low triggering threshold'' for requiring a source to control emissions, adding that ''the NAS correctly noted that Congress has not required ironclad scientific certainty establishing the precise relationship between a source's emission and resulting visibility impairment. * * *''[43] In considering whether additional States should be subject to the visibility program, EPA believes the court's reasoning supports adoption of the predicate requirement that States develop the necessary provisions in their implementation plans to determine whether and to what extent control of emissions from sources is needed. That is, given that the court believed this ''low triggering threshold'' was sufficient to require a source to control its emissions under BART, EPA believes it is reasonable that a similarly low or even lower threshold applies to whether States should be required to engage in air quality planning and analysis as a prerequisite to determining the need for control of emissions from sources within their State. The EPA believes this is particularly appropriate since the requirement for SIPs does not mandate the actual control of emissions from any source without further technical analysis by the State. Accordingly, EPA believes the concept of an ''extremely low triggering threshold'' can also apply in determining which States should submit SIPs for regional haze.

Section 169A(a)(1) sets forth a national goal of ''the prevention of any future, and the remedying of any existing, impairment of visibility in Class I areas which impairment results from manmade air pollution.'' Thus, in addition to requiring a program to reduce existing impairment, the CAA requires SIPs to be established in order to prevent future impairment. This preventative component of the national goal requires that States have the framework in place to address future growth in emissions from new sources or other activities that could impair visibility. For this reason, the EPA does not believe that it is appropriate to establish criteria for excluding States or geographic areas from consideration as potential contributors to regional haze visibility impairment.

As noted in the proposal, EPA is not specifying in this final rule what specific control measures a State must implement in its initial SIP for regional haze. That determination can only be made by a State once it has conducted the necessary technical analyses of emissions, air quality, and the other factors that go into determining reasonable progress. As discussed in section II(F), because of the regional, multistate nature of visibility impairment in Class I areas,[44] EPA recommends that these analyses and the determination of the extent of emissions reductions needed from individual States be developed and refined through multistate planning efforts using the best available technical tools, such as regional-scale modeling. The EPA also recommends the coordination of resulting strategies for regional haze with strategies needed to attain the $PM_{2.5}$ NAAQS. The EPA anticipates that as a result of the more refined analyses required by this rule, some States may conclude that control strategies specifically for protection of visibility are not needed at this time because the analyses may show that existing measures are sufficient to meet reasonable progress goals. The EPA is requiring States to document their analyses, including any consultations with other States in support of their conclusions that further controls are not needed at this time. The EPA believes that there is more than sufficient evidence to support our conclusion that emissions from each of the 48 contiguous States may be reasonably anticipated to cause or contribute to visibility impairment in a Class I area.

As stated in EPA's proposal, a large body of evidence demonstrates that long-range transport of fine PM contributes to regional haze and other related effects such as acid rain. In the preamble to the proposal and in the relevant docket, EPA cited numerous studies that contribute to this body of evidence.[45] Indeed, EPA recognized the role of long-range transport in relation to visibility impairment 20 years ago in its 1979 Report to Congress on visibility.[46]

Among the more important studies on which EPA relied are the 1991 report from the NAPAP, the 1993 NAS report Protecting Visibility in National Parks

[42] *Central Arizona Water Conservation District* v. *EPA*, 990 F.2d 1531 (1993).

[43] 990 F.2d at 1541.

[44] Refer to unit II of this final rule for additional background on the long-range transport of pollution contributing to regional haze.

[45] See Unit II, Background Information. See also July 29, 1997 memorandum to regional haze docket A–95–38, ''Supporting Information for Proposed Applicability of Regional Haze Regulations,'' by Richard Damberg, EPA, Office of Air Quality Planning and Standards.

[46] U.S. EPA, Protecting Visibility: An EPA Report to Congress, Office of Air Quality Planning and Standards, EPA–450/5–79–008, October 1979.

and Wilderness Areas, EPA studies using the regional acid deposition model (RADM), the 1996 GCVTC report Recommendations for Improving Western Vistas, and two contractor reports prepared for EPA.[47] All of these reports are available in the docket. They were referenced and discussed in EPA's proposal and in an additional memorandum to the docket. The NAPAP report included a comprehensive technical review of historical visibility trends.[48] The NAS report found that the range of fine particle transport is on the order of hundreds or thousands of kilometers.[49] Analyses using the RADM have estimated that sulfate and nitrate deposition receptors are influenced by sources located up to 600–800 kilometers away.[50] In its deliberations and in its final report, the GCVTC acknowledged the role of long-range transport from sources and activities located across a very large geographic area, and its effect on the Class I areas on the Colorado Plateau.[51]

Finally, two contractor modeling reports prepared for EPA provided information that preliminarily demonstrated that each State not having a Class I area had emissions contributing to impairment in at least one downwind Class I area. Some State commenters asserted that the contractor reports referenced in the proposal show relatively low contributions from all or part of their States toward visibility impairment in a nearby Class I area. As a result, these commenters suggested that EPA had sufficient information to reach a conclusion that all or part of their States could be excluded from the regional haze program. The EPA disagrees with these comments for two reasons.

First, the EPA did not base its proposed applicability provisions only on the referenced contractor reports. The EPA based its decision on the assessments provided by these reports as well as a number of other studies and sources of information. Second, as explained above, EPA believes that all States must have a visibility SIP to prevent, at a minimum, future impairment of visibility. While EPA agrees that portions of some States may not need to implement additional measures, at this time, to improve visibility impairment in any Class I area, the EPA believes that more refined future assessments will be needed to support such a finding. Additionally, the EPA believes that a State wishing to demonstrate that it does not contribute to visibility impairment in any Class I area will need to provide information showing that it has consulted with other potentially affected States to assist EPA in assuring that the State's demonstration is not contradicted by evidence presented by other States.

Current monitoring information for Class I areas shows that all of the monitored sites in the central and eastern parts of the country have visibility impairment levels exceeding estimated natural conditions for the 20 percent most impaired days, some by more than 20 deciviews. Although the degree of impairment varies, the data demonstrate that no existing site has reached the goal in section 169A(a)(1) of the CAA for ''remedying * * * any existing impairment of visibility.''[52]

In light of this finding, EPA disagrees with the commenter who asserted that because visibility levels in its State are already ''acceptable,'' there is no need for the State to implement a regional haze program. The section 169A national goal of the visibility program, a condition of no human-caused impairment, does not provide for judgments of acceptable visibility levels which are poorer than natural conditions in Class I areas. Through adoption of section 169A(a)(1), Congress established natural visibility conditions as the overall goal.

The data also show that in the monitored locations in the central and eastern United States, sulfate is the key contributor to visibility impairment, responsible for between 45–90 percent of light extinction due to aerosols on the 20 percent most impaired days. This fact is significant because the broad, regional scale of long-range transport of sulfate has already been acknowledged in many studies done for the acid rain program. Based on these data, it appears that although the acid rain program is expected to improve visibility by approximately 3 deciviews in the most impaired Class I areas in the Eastern United States by 2005,[53] further regional reductions in SO_2 emissions may be needed after the acid rain program is complete to assure continued visibility improvement toward the national goal. Thus, EPA finds it is reasonable to require SIPs from the States without Class I areas which are located in the central and eastern parts of the United States since many, if not all, are expected to have sources contributing to regional loadings of SO_2 emissions, even after implementation of the acid rain program is completed.

For all of the reasons stated above, EPA has concluded in today's final rule that EPA's statutory authority and scientific evidence are sufficient to require all States to develop regional haze SIPs to ensure the prevention of any future impairment of visibility, and to conduct further analyses to determine whether additional emission reduction measures are needed to ensure reasonable progress in remedying existing impairment in downwind Class I areas.

B. Timetable for Submitting the First Regional Haze State Implementation Plan (SIP)

This final rule establishes a schedule setting forth deadlines by which the States must submit their first regional haze SIPs and subsequent revisions to that first SIP. In this unit, we discuss the deadlines for the first regional haze SIP, the concerns raised in comments regarding these deadlines, and recent legislation affecting the deadlines. The requirements for periodic revisions to this first regional haze SIP are discussed below in unit III.J.

Proposed rule. The proposed rule, consistent with section 169B(e)(2) of the CAA, would have required States to submit revisions to their SIP to address regional haze within 12 months of the effective date of the rule. We had intended that these 12-month SIP

[47] See Latimer and Associates, Particulate Matter Source—Receptor Relationships Between All Point and Area Sources in the United States and PSD Class I Area Receptors, Report prepared for EPA, Office of Air Quality Planning and Standards, September 1996. See also ENVIRON International Corporation, Development of Revised Federal Class I Area Groups in Support of Regional Haze Regulations, Report prepared for EPA, Office of Air Quality Planning and Standards, September 1996.

[48] National Acid Precipitation Assessment Program. Acid Deposition: State of the Science and Technology. Report 24, Visibility: Existing and Historical Conditions—Causes and Effects, Washington, DC, 1991.

[49] National Research Council, NAS Committee on Haze in National Parks and Wilderness Areas, Protecting Visibility in National Parks and Wilderness Areas, National Academy Press, Washington, D.C., 1993.

[50] Dennis, Robin L. ''Using the Regional Acid Deposition Model to Determine the Nitrogen Deposition Airshed of the Chesapeake Bay Watershed,'' in Atmospheric Deposition to the Great Lakes and Coastal Waters, edited by Joel Baker, 1996.

[51] GCVTC, Recommendations for Improving Western Vistas, Report to the U.S. EPA, June 1996.

[52] Sisler, J. *et al.,* Spatial and Seasonal Patterns and Long-Term Variability of the Chemical Composition of the Haze in the United States: An Analysis of Data from the IMPROVE Network, Fort Collins, CO, Cooperative Institute for Research in the Atmosphere, Colorado State University, 1996. See also Sisler, J., et al., Spatial and Temporal Patterns and the Chemical Composition of the Haze in the United States: An Analysis of Data from the IMPROVE Network, 1988–1991, Fort Collins, CO, 1993.

[53] U.S. EPA, Effects of the 1990 Clean Air Act Amendments on Visibility in Class I Areas: An EPA Report to Congress, Office of Air Quality Planning and Standards, EPA–452/R–93–014, October 1993.

submittals serve as program planning SIPs in which the States would review existing regulatory authorities and provide the framework for a number of future actions.

Comments received. Commenters expressed the view that 12 months was an insufficient time period to meet the proposed requirements for the program planning SIP. Moreover, commenters were concerned that the 12-month SIP requirement was not well coordinated with similar program planning for the new $PM_{2.5}$ standard.

Transportation Equity Act for the 21st Century (TEA–21). After the close of the comment period for the July 1997 proposal, Congress passed the Transportation Equity Act for the 21st Century (TEA–21), Public Law 105–178. The TEA–21 superseded the statutory requirement for a 12-month SIP deadline and established a specific schedule for regional haze SIP submissions. In a September 3, 1998 notice of availability, EPA provided the public with an opportunity to comment on how the regional haze rule should address the TEA–21 requirements.[54]

The TEA–21 provisions establish a timetable for the regional haze SIPs by first creating certain deadlines for $PM_{2.5}$ monitoring and area designations, and then by linking those deadlines to further deadlines for the regional haze program. The TEA–21 amendments, in section 4102(a), require EPA to fund a $PM_{2.5}$ monitoring network. In section 4102(b), EPA and States are required to put this network in place by no later than December 31, 1999.

Section 4102(c)(1) of TEA–21 establishes deadlines for States to use the data collected by the network for purposes of formally designating areas as attaining the $PM_{2.5}$ standard or as nonattainment or unclassifiable. Section 4102(c)(1) states:

(1) The Governors shall be required to submit designations referred to in section 107(d)(1) of the CAA for each area following promulgation of the July 1997 $PM_{2.5}$ national ambient air quality standard within 1 year after receipt of 3 years of air quality monitoring data performed in accordance with any applicable Federal reference method for the relevant areas.

Section 4102(c)(2) of TEA–21 contains the following language which links the timing requirements for the visibility program to the $PM_{2.5}$ designation process:

(2) For any area designated as nonattainment for the July 1997 $PM_{2.5}$ national ambient air quality standard in accordance with the schedule set forth in this section, notwithstanding the time limit prescribed in paragraph (2) of section 169B(e) of the CAA, the Administrator shall require State implementation plan revisions referred to in such paragraph (2) to be submitted at the same time as State implementation plan revisions referred to in section 172 of the CAA implementing the revised national ambient air quality standard for fine particulate matter are required to be submitted. For any area designated as attainment or unclassifiable for such standard, the Administrator shall require the State implementation plan revisions referred to in such paragraph (2) to be submitted 1 year after the area has been so designated. The preceding provisions of this paragraph shall not preclude the implementation of the agreements and recommendations set forth in the GCVTC Report dated June 1996.

To accompany the statutory changes contained in the TEA–21 law, Congress released a Conference Report. With respect to the visibility provisions of TEA–21, the Conference Report states:

The Conferees recognize that the Regional Haze regulation has not been finalized and the Administrator of the Environmental Protection Agency (EPA) is still considering the views of various stakeholders. The Conferees agree with EPA's public statements that the schedule for the State Implementation Plan due pursuant to section 169B(e)(2) of the * * * [Clean Air] * * * CAA should be harmonized with the Schedule for State Implementation Plan submissions required for $PM_{2.5}$ ambient air quality standard promulgated in July, 1997.[55]

This new statutory language has two effects. First, it supersedes the section 169B requirement for EPA to require States to submit SIPs within 12 months of the promulgation of today's final rule. Second, it spells out a timetable for SIP revisions that is linked to the dates of attainment/nonattainment designations for $PM_{2.5}$. It is important to note that the timetable is based on the designation of areas within a State. Thus, under the legislation, one State could have multiple SIP submission deadlines depending on the dates of designation of each area within the State. This issue, and how EPA intends to address it, is further discussed later in this unit.

According to a Presidential memorandum dated July 16, 1997, the EPA and States must collect 3 years of monitoring data in order to have a sufficient basis for designations. This point is reiterated in TEA–21.[56] Routine collection of monitoring data begins in 1999. Hence, we expect the requirements of TEA–21, section 4102(c)(1), to result in the following:

Submissions of designation requests by States. States must submit designations within 1 year of the date that 3 years of $PM_{2.5}$ data are available. Because widespread monitoring for $PM_{2.5}$ is being implemented between January 1999 and December 31, 1999, we expect 3 years of data to be collected by December 31, 2001 for most areas and no later than December 31, 2002 for the remaining areas. Taking into account additional time (not more than 6 months) for quality assurance and certification of the data, we expect 3 years of data to be available for States to use for designations between July 2002 and July 2003. In the TEA–21 amendments, States have up to 1 year to submit designations. Thus, we expect that the required date for submittal of designations generally will occur between July 2003 and July 2004.[57]

EPA action on State designations. The EPA is required to act upon the designations no later than 1 year after the date States are required to submit the designations, but not later than December 31, 2005 in any case. If States submit their designations between July 2003 and July 2004, EPA would be required to designate areas between July 2004 and July 2005.

For areas designated as attainment or unclassifiable, the TEA–21 amendments require that States must submit SIPs for regional haze within 1 year after EPA publishes the designations. As a result, for these areas, regional haze SIPs are likely to be due generally between July 2005 and July 2006.

For areas designated as nonattainment for fine particulate matter, the TEA–21 amendments require States to submit SIP revisions addressing regional haze "at the same time as States submit SIPs as required by section 172 of the CAA implementing the July 1997 revision to the national ambient air quality standard for fine particulate matter." Section 172(b) of the CAA requires SIPs no later than 3 years after EPA publishes the nonattainment designation. If EPA designates areas nonattainment between July 2004 and July 2005, the regional haze SIPs for areas designated as nonattainment and the $PM_{2.5}$ nonattainment SIPs would both be due no later than the July 2007 to July 2008 timeframe.

The date for startup of $PM_{2.5}$ monitoring may vary in different parts of a given State. Accordingly, the EPA expects that States may not be able to submit designation requests at the same time for the entire State. Rather, EPA

[54] 63 FR 46952.

[55] H.R. Conf. Rep. No. 550, 105th Cong., 2d. Sess. 519 (1998), reprinted in 1998 U.S.C.C.A.N., No. 6 at 196.

[56] See TEA–21, Section 4102(c)(1).

[57] We expect that some States will want to move expeditiously with some designations, leading to submissions and final action on some areas as early as late 2002 or early 2003. Where this is the case, this would lead to earlier regional haze SIP submittal deadlines as well.

expects that it is possible that individual ''areas'' within a given State may be designated at different times. Even if areas were all designated at the same time, in many States some areas will likely be designated attainment, with others designated nonattainment. In either case, the TEA–21 deadlines would require separate regional haze SIPs for each of these areas to be submitted at different times.

While the language in TEA–21 establishing the timetable for submission of regional haze SIPs is generally clear, the transportation legislation does not address the situation where States are participating in a regional planning effort that incorporates numerous areas. On its face, TEA–21 requires the submission of separate regional haze SIPs on an area-by-area basis with varying deadlines that could range over a period of several years. As noted above, however, regional haze is the result of emissions from a number of sources located over a broad geographic area. Because of the long-range transport of pollutants causing regional haze, EPA believes that well-coordinated regional planning efforts are needed to make progress toward natural visibility conditions. As EPA noted in the September 3, 1998 notice of availability, we do not believe that Congress intended to inhibit regional planning efforts by requiring area-by-area submittals. In light of this, EPA requested comment on incorporating an optional approach into the final rule to facilitate regional planning.

Notice of availability of additional information. The optional approach EPA described in the September 3, 1998 notice of availability would allow States which commit to participating in regional planning efforts to postpone addressing certain of the requirements of the regional haze program. Under this approach, States would have the option to first submit SIPs which contain commitments to specific integrated regional planning efforts but which do not set forth control strategies. States committing to regional planning would subsequently submit SIP revisions containing control strategies for attainment, unclassifiable, and nonattainment areas at the same time. This would allow multiple areas within a single planning region to have coordinated deadlines for regional haze control strategies. In the supplemental notice, we noted that this approach could have the effect of delaying control strategy plan submittal dates for some areas, but we believe that such an option will support more effective coordination between the $PM_{2.5}$ and regional haze programs, will support coordinated regional planning for both programs, and will be consistent with the statement of congressional intent.

Comments received. Some commenters argued that TEA–21 does not authorize EPA to defer implementation of the regional haze program in this way. The basis for this argument is the claim that the 1-year deadline in section 169B(e)(2) applies only to regulations promulgated pursuant to the report of a visibility transport commission. These commenters claim that EPA is obligated under section 169A to provide for more expedited implementation of measures to assure reasonable progress.

The final rule. The regulations made final today are issued under the authority of CAA sections 169A and 169B. As discussed in unit II.C above, EPA in 1980 explicitly deferred issuing regulations to address regional haze until our scientific and technical knowledge was better developed. In 1990, Congress amended the CAA by adding section 169B. This section authorizes the establishment of visibility transport commissions which, among other things, must issue a report addressing ''the promulgation of regulations under [section 169A] to address long range strategies for addressing regional haze.'' Section 169B further establishes explicit timeframes in which EPA must, taking into account any reports of visibility transport commissions, issue regulations under section 169A, and in which States must respond by submitting revised SIPs. Congress modified the timeframe for SIP submission in TEA–21 to ensure the ability of EPA to harmonize the implementation of today's final rule with the requirements for the new $PM_{2.5}$ NAAQS.[58] Today's final rule carries out EPA's obligation under sections 169A and 169B to issue regulations addressing regional haze according to the timeframe as set forth in section 169B as modified by TEA–21.

The final rule includes the deadlines for SIP submittals set forth in TEA–21 and incorporates an optional set of requirements for States which commit to participate in regional planning. Commenters generally agreed with EPA's view in the notice of availability that it is important to ensure that the $PM_{2.5}$ program and regional haze program are fully integrated. The EPA believes that the approach taken in the final rule supports effective coordination between these programs, while also facilitating regional planning.

In the final rule, the timetable for SIP submittals is set forth in section 51.308(b) and (c). Section 51.308(b) directly codifies the TEA–21 timetable. Section 51.308(c) provides States that have committed to participate with other States in a regional planning process the option of choosing to defer submittal of a SIP which addresses the substantive requirements of the regional haze program. States are not required to exercise the option provided by section 51.308(c), but those which do must meet the deadlines set forth in that section for submitting a SIP which addresses the distinct requirements in section 51.308(c) and a SIP revision which addresses the substantive requirements of the regional haze program.[59]

As a first step, States electing to participate in regional planning must submit a SIP demonstrating the State's ongoing participation in a regional planning process. This SIP must address all areas in the State and is due on the earliest date by which an implementation plan affecting any area within the State would be due under the TEA–21 deadlines. Unless an entire State is designated as nonattainment, this SIP will be due 1 year after EPA designates any area within the State as attainment or unclassifiable. This SIP submission must contain a number of specific elements to demonstrate the State's commitment to the regional planning process and to ensure that by the date of the SIP submittal, the States in the regional planning body have taken the necessary steps to initiate the regional planning process.

The following briefly summarizes the required elements of the first SIP submittal called for under the optional approach for regional planning:

Need for regional planning. In the SIP, the State must demonstrate the need for regional planning. The State must make this demonstration by showing that emissions from sources within the State contribute to visibility impairment in Class I areas in another State, or by showing that other States contribute to visibility impairment in the Class I areas in the State. The EPA does not intend for this to be an overly complex analysis.

Description of regional planning organization. The State must also submit a detailed description of the regional planning process. In its SIP, the State must show that the participating

[58] See H.R. Conf. Rep. No. 550, 105th Cong., 2d. Sess. 517.

[59] The option for regional planning provided by section 51.308(c) is not available for Alaska, Hawaii, and the Virgin Islands. Class I areas within their boundaries are not affected by emissions from any other State. As a result, regional planning will not be needed to develop regional haze SIPs for these areas.

States have a credible regional planning process in place which all parties are committed to follow. We have outlined general principles for regional planning organizations in a document entitled Implementation Guidance for the Revised Ozone and Particulate Matter (PM) National Ambient Air Quality Standards (NAAQS) and the Regional Haze Program, which discusses features of effective regional planning organizations, including a discussion of organization and representation issues, issues related to developing workplans and schedules, and issues related to ensuring that technical efforts are consistent. This document is available on the internet at http://www.epa.gov/ttn/oarpg/t1pgm.html.

Enforceable commitment to submit coordinated control strategy by 2008. The regional planning SIP must include provisions requiring the State to submit a SIP revision meeting all of the requirements of the regional haze rule. This SIP revision is due by the latest date an area within the planning region would be required to submit an implementation plan under TEA–21, but in no event any later than December 31, 2008. The SIP must require that the SIP revision is developed in coordination with the other States in the regional planning body and that it fully addresses the recommendations of that body.

List of BART-eligible sources. The State must identify those sources from one of 26 source categories and placed into operation between 1962 and 1977 that are potentially subject to BART. This information will enable the State and regional planning organization to begin evaluating options for meeting the BART requirement or for implementing an emissions trading program or alternative measure that achieves greater reasonable progress.

Summary of timetable for submission of the first regional haze SIPs. The following table is a summary of the deadlines for submitting the first regional haze SIPs.

For this case . . .	. . . States must submit the first regional haze SIPs no later than:	. . . and the SIP must meet . . .
Areas designated as attainment or unclassifiable for $PM_{2.5}$.	1 year after EPA publishes the designation (generally 2004–2006).	ALL requirements of section 51.308(d) and (e).
Areas designated as nonattainment for $PM_{2.5}$ ...	At the same time as $PM_{2.5}$ SIPs are due under section 172 of the CAA. (That is, 3 years after EPA publishes the designation, generally 2006–2008).	ALL requirements of section 51.308(d) and (e).
States participating in multistate regional planning efforts for combined attainment and nonattainment areas.	Two phases:	
	Commitment to regional planning due 1 year after the EPA publishes the first designation for any area within the State, and.	The regional planning requirements listed in section 51.308(c).
	Complete implementation plan due at the same time as $PM_{2.5}$ SIPs are due under section 172 of the CAA. (That is, 3 years after EPA publishes the designation).	The ''core requirements'' listed in section 51.308(d) and BART requirements in section 51.308(e).
States following the recommendations of the GCVTC, as contained in section 51.309 of the final rule.	December 31, 2003	SIPs must meet the specific provisions for Grand Canyon Transport Region States listed in section 51.309.

C. Tracking Deciviews and Emissions Reductions

Visibility impairment is caused by particles and gases in the atmosphere. Some particles and gases scatter light, while others absorb light. The net effect is called ''light extinction.'' The result of these processes is a reduction of the amount of light from a scene that is returned to the observer, creating a hazy condition.

Proposed rule. In the proposal, EPA established a regulatory framework by which a State would establish a ''reasonable progress target'' for each Class I area within its borders for the purpose of improving visibility on the worst visibility days over the next 10 or 15 years. The States would implement emission management strategies to improve visibility in these Class I areas. The proposal also called for the States to monitor progress in improving visibility over time. The EPA proposed that visibility targets and tracking of visibility changes over time be expressed in terms of the ''deciview'' haze metric. The proposal also called for the tracking of pollutant emissions to supplement the tracking of monitored visibility changes for use in periodically reviewing State progress in achieving visibility targets. The proposal included the definition of the deciview metric for tracking visibility. The proposal also called for a review of emissions reductions achieved as part of the long-term strategy.

Deciview. The proposal explained that the deciview is an atmospheric haze index that expresses changes in visibility. This visibility metric expresses uniform changes in haziness in terms of common increments across the entire range of visibility conditions, from pristine to extremely hazy conditions.[60] Because each unit change in deciview represents a common change in perception, the deciview scale is like the decibel scale for sound. The proposal also stated that ''A one deciview change in haziness is a small but noticeable change in haziness under most circumstances when viewing scenes in Class I areas.''[61]

The proposal discussed that an advantage to using the deciview over other scales is that it can be used to express changes in visibility impairment in a way that corresponds to human perception in a linear, or one for one, manner. For example, this metric is designed such that a change of 3 deciviews in a highly impaired environment would be perceived as roughly the same degree of change as a 3 deciview change in a relatively clear environment. As noted in the preamble to the proposed regulation, the deciview is mathematically related to other common metrics used to describe visibility: the light extinction coefficient and visual range. However, the deciview metric can be used to compare changes in perception in a way that the other two metrics cannot. This feature makes the deciview a more useful metric for regulatory purposes. For example, a 5-

[60] Pitchford, M. and Malm, W., ''Development and Applications of a Standard Visual Index,'' Atmospheric Environment, v. 28, no. 5, March 1994.

[61] 62 FR 41145.

mile change in visual range can in some cases be very significant, such as from 5 to 10 miles in an impaired environment (equal to a change of 6.9 deciviews), whereas a 5-mile change may not be perceptible in a less impaired environment, such as from 95 to 100 miles (equal to a change of 0.5 deciviews). The following sections discuss the comments received on specific issues and how such issues are addressed in the final rule.

Tracking emissions versus visibility. Many commenters supported the use of the deciview metric to track changes in visibility improvement as a key aspect of the program. These commenters agreed with EPA's proposal that under a visibility-oriented program, progress in fact should be tracked in terms of a visibility-based metric. Others felt the program could be successfully implemented by tracking emissions only because this approach would not be greatly affected by meteorological variations as would an approach based on ambient monitoring.

The final rule provides for the tracking of both visibility improvement and emissions reductions.[62] The final rule presents visibility improvement and tracking of emissions as linked elements of the program. The EPA has retained the use of the deciview metric for tracking changes in visibility. The EPA believes the tracking of actual visibility improvements is necessary to be responsive to the goals of the CAA. Section 169A(a) of the CAA sets forth the national goal of the ''prevention of any future, and the remedying of any existing, impairment of visibility in Class I areas which impairment results from manmade air pollution.'' The CAA also requires EPA to establish regulations to be implemented by the States to ensure that 'reasonable progress' is made toward the national goal. In addition, section 169B(e) of the CAA calls for EPA to carry out its ''regulatory responsibilities under section 169A, including criteria for measuring 'reasonable progress' toward the national goal.'' [63]

The EPA believes that tracking of emissions reductions is also an important component of the regional haze program. The mechanism for achieving improvements in visibility will be the implementation of enforceable emissions reduction measures that have been adopted as part of the SIP. Tracking emissions will provide a good indicator of whether adopted measures are reducing emissions and is thus a useful indicator of progress in reducing visibility impairment. The tracking of emissions without concurrently tracking changes in visibility, however, would be problematic because of the variable effect on visibility of each of the principal constituents of PM, the more significant light scattering efficiency of fine PM versus coarse PM, and the generally greater effect of nearby versus distant sources on visibility impairment.

Since the national goal is expressed in terms of air quality (i.e., visibility) rather than emissions, we believe that it is very important to require the quantitative tracking of visibility impairment as an integral element in measuring reasonable progress. Because ambient monitoring data are subject to meteorological fluctuations, EPA designs standards and requirements for analysis of monitoring data to limit the effects of unusual meteorological events. For regional haze, we have provided in this final rule for the tracking of visibility trends based on 5-year averages of annual deciview values for the most impaired and least impaired days. We believe that this approach responds to commenters' concerns about significant unusual fluctuations in annual average values for the best and worst days due to unusual meteorological conditions in any particular year. However, it is also important to note that EPA has long held that normal meteorological variations should be explicitly accounted for in air quality analyses and control strategy design. Air quality improvement plans should be able to assure protection of public health and welfare under the normal and foreseeable range of meteorological conditions.

Tracking visibility in deciviews. Some commenters disagreed with the use of the deciview to measure changes in visibility, claiming that the deciview metric has not been adequately reviewed for use in a regulatory program. The EPA disagrees with this assertion. The EPA believes the deciview metric has been adequately reviewed for use in the regional haze program. The deciview concept was introduced in 1994 in an article appearing in the peer-reviewed journal Atmospheric Environment.[64] It was presented in the 1996 Criteria Document for the PM NAAQS as a valid metric for characterizing visibility impairment.[65] The EPA also recognized the deciview as an appropriate metric for regulatory purposes in chapter 8 of the 1996 Staff Paper for the PM NAAQS review.[66] Both of these documents were reviewed and accepted by the Clean Air Scientific Advisory Committee. Visibility conditions at Class I areas have been characterized in terms of deciview in summary reports on the IMPROVE visibility monitoring network.[67]

The EPA also supports use of the deciview metric because it satisfies one of the recommendations of the NAS Committee on Haze in National Parks and Wilderness Areas. In its 1993 report on visibility, the NAS recommended the development of an index that takes into account both measurement of physical changes (i.e., changes in air quality) with elements of human perception.[68] Further, a report on the regional haze proposal by the Congressional Research Service found that the deciview index ''conforms closely'' [69] to the NAS recommendation cited above.

Some commenters stated that the final rule should not suggest that a one deciview change is the threshold of perception in all cases for all scenes. The EPA agrees with the comment that a one deciview change should not be considered the threshold of perception in all cases for all scenes. The EPA believes that visibility changes of less than one deciview are likely to be perceptible in some cases, especially where the scene being viewed is highly sensitive to small amounts of pollution. The EPA also acknowledges the technical point made by some commenters that for other types of scenes with other site-specific

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[62] Tracking of visibility is addressed in section 51.308(d) and 51.308(g). Tracking of emissions reductions is addressed in section 51.308(g).

[63] Section 169B(e)(1).

[64] Pitchford, M. and Malm, W., ''Development and Applications of a Standard Visual Index,'' Atmospheric Environment, V. 28, no. 5, March 1994.

[65] U.S. EPA, Air Quality Criteria for Particulate Matter, Research Triangle Park, NC, National Center for Environmental Assessment. Office of Research and Development, July 1996.

[66] U.S. Environmental Protection Agency. Review of the National Ambient Air Quality Standards for Particulate Matter: Policy Assessment of Scientific and Technical Information. OAQPS Staff Paper. Office of Air Quality Planning and Standards. July 1996.

[67] Sisler, J., *et al.*, Spatial and Seasonal Patterns and Long-Term Variability of the Composition of the Haze in the United States: An Analysis of Data from the IMPROVE Network. Cooperative Institute for Research in the Atmosphere, Colorado State University, 1996. See also Sisler, J., et al., Spatial and Temporal Patterns and the Chemical Composition of the Haze in the United States: An Analysis of Data From the IMPROVE Network, 1988–1991, Fort Collins, CO, 1993.

[68] National Research Council, Protecting Visibility in National Parks and Wilderness Areas, 1993, p. 354.

[69] Congressional Research Service, Regional Haze: EPA's Proposal to Improve Visibility in National Parks and Wilderness Areas, November 17, 1997, p. 17.

conditions,[70] a change of more than 1 deciview might be required in order for the change to be perceptible. However, EPA wishes to emphasize that the overall goal of the regional haze program is not to track changes in visibility for only certain vistas at a specific Class I area. Rather, the program is designed to track changes in regional visibility for the range of possible views of sky and terrain found in any Class I area, and to assure progress toward the national goal. For this purpose, EPA supports the use of the deciview metric as calculated from ambient monitoring data for tracking changes in regional visibility. The monitoring network is not designed to track changes in visibility for specific views in each Class I area. Rather, the network is designed to characterize visibility conditions that, for each site, are representative of a fairly broad geographic region. The EPA believes this approach is consistent with the nature of regional haze, which is defined as a uniform haze caused by numerous sources covering a broad area. Thus, although a 1 deciview change may not be the threshold of perception in all situations, the fundamental advantage of using the deciview remains: the deciview metric expresses uniform changes in haziness in terms of common increments across the entire range of visibility conditions, from pristine to extremely hazy conditions. The metric provides a useful means of expressing changes in visibility caused by changes in air quality while also providing a scale that relates visibility to perception. The final rule maintains the deciview as the principle visibility metric used in establishing reasonable progress goals, in defining baseline, current, and natural conditions, and in tracking changes in visibility conditions over time. States may choose to express visibility changes in terms of other metrics, such as visual range or light extinction, as well as in terms of deciview. The definition in the final rule was modified slightly to provide additional clarity.

Light extinction calculated from aerosol data. Some other commenters did not support EPA's proposed approach to calculating light extinction based on monitored fine particle data (referred to as ''reconstructed light extinction'' in the proposal). These commenters preferred other methods, such as direct measurement of light scattering or light extinction with an optical device. While such methods are desired in comprehensively monitoring visibility impairment, the EPA supports the use of a common approach for calculating visibility changes based on monitored fine particle data as the primary monitoring method for tracking visual air quality.

Such an approach has been established and implemented for many years by the IMPROVE Steering Committee. The IMPROVE approach uses a set of standard assumptions,[71] which have been tested and found to be reasonable, in calculating light extinction and deciviews from changes in air quality. Two important aspects of the approach are: (1) Standard rates of light extinction per unit mass of visibility-impairing pollutants (e.g., sulfate, nitrate, organic carbon, elemental carbon, and crustal material); and (2) standard effects of humidity on sulfate and nitrate.

Through extensive analysis of empirical data, a value (or ''dry extinction coefficient'') has been developed for each aerosol component which represents the amount of light extinction (expressed in inverse megameters) caused by each microgram/m3 of that component. Light extinction is calculated by multiplying the aerosol mass for each component by its extinction coefficient and summing the products. Because sulfates and nitrates become more efficient at scattering light as humidity increases, the values for these two components are also multiplied by a relative humidity adjustment factor. It has been shown that annual and seasonal light extinction values developed according to this method correlate well with averages of optical measurements of light extinction for the same locations.[72] The EPA plans to issue future guidance describing the details of calculating visibility changes in this manner and tracking visibility over time.

Although light extinction can be measured directly by certain optical devices (i.e., transmissometers and nephelometers), EPA supports an approach based on the mass of PM components derived from ambient monitoring for calculating light extinction for two main reasons. First, this approach provides for the tracking of actual changes in the components of air pollution, and the information obtained from analysis of the chemical composition of PM is critical to the air quality modeling and strategy development processes. By understanding the chemical composition of particulate matter, we can better define the manmade and natural components contributing to overall light extinction. Second, direct measurements of visibility from some optical instruments (e.g., transmissometer) are more frequently disrupted by precipitation events (i.e., rain or snow) than are aerosol measurements.

For all of the reasons discussed above, the final rule provides for the tracking of visibility and emissions reductions. The deciview will be the principal visibility metric for use in implementing the regional haze program. The deciview will be used for expressing reasonable progress goals, defining baseline, current, and natural conditions, and tracking changes in visibility conditions over time. The definition of deciview in the final rule in section 51.301(bb) was modified slightly to provide additional clarity and state that deciview values are to be derived from calculated light extinction based on aerosol measurements in accordance with EPA guidance.

D. Regional Haze Implementation Plan Principles

Section 169A of the CAA calls for States to develop implementation plans ensuring reasonable progress toward the national goal, including emission limits, schedules of compliance and other measures as necessary. At a minimum, the CAA calls for SIPs to include a long-term strategy and provisions for BART for certain major stationary sources. We would like to emphasize several overarching themes for the specific implementation plan requirements in the final rule:

- Regional haze regulations and State implementation plans must address all of the statutory requirements outlined in 169A and 169B of the CAA. Regional haze requirements must address a number of specific statutory requirements, including ''criteria for reasonable progress,'' long-term strategies addressing all types of sources and activities, and best available retrofit technology for certain stationary sources. The implementation plan requirements in the final rule are designed to ensure that all of these statutory requirements will be met.
- Tracking ''reasonable progress'' should involve the tracking of both emissions and visibility improvement. Regional haze implementation plans must include provisions for tracking the implementation of enforceable emission management strategies designed to make reasonable progress toward the national

[70] For example, where the sight path to a scenic feature is less than the maximum visual range.

[71] See Sisler, *et al.*, Spatial and Seasonal Patterns and Long-Term Variability of the Composition of the Haze in the United States: An Analysis of Data from the IMPROVE Network. Cooperative Institute for Research in the Atmosphere, Colorado State University, 1996.

[72] Id.

visibility goal. Emission control measures will be the component that will be enforceable to ensure reasonable progress. Measuring reasonable progress should involve tracking the actual emissions achieved through implementation of such strategies, and the tracking of visibility for the most impaired and least impaired days using established monitoring and data analysis techniques.

• Strategies for improving visibility should address all types of sources. Section 169A provides for State long-term strategies to address all types of sources and activities emitting pollutants that contribute to visibility impairment in Class I areas, including stationary, mobile, and area sources. Implementation plans also must give specific attention to certain stationary sources built between 1962 and 1977 and provide for meeting the BART provisions for these sources.

• Successful implementation of the regional haze program will involve long-term regional coordination among States. Pollution affecting the air quality in Class I areas can be transported long distances, even hundreds of kilometers. Therefore, States will need to develop strategies in coordination with one another, taking into account the effect of emissions from one jurisdiction to air quality in another. In addition, as noted by the NAS study, ''achieving the national visibility goal will require a substantial, long-term program.'' [73] Accordingly, the regional haze program requires the periodic review by each State of whether ''reasonable progress'' is being achieved and revisions of implementation plans as needed to continue progress toward the national visibility goal.

E. Determination of ''Baseline,'' ''Natural'' and ''Current'' Visibility

Background. The fundamental goal of the visibility program, as provided by Congress, is the prevention of future visibility impairment and the remedying of existing impairment in Class I areas. Thus, the regional haze program must track progress toward the national goal.

In order to facilitate this tracking process, the proposed rule required each State having one or more Class I areas to establish, and update as necessary, three important visibility parameters for the best and worst visibility days at each Class I area within the State. Each parameter is discussed in detail below.

• Baseline conditions—Baseline conditions represent visibility for the best and worst days at the time the regional haze program is established. Baseline conditions are calculated using multiyear averaging.

• Natural conditions—As specified in the CAA, estimated natural conditions, or the visibility conditions that would be experienced in the absence of human-caused impairment, constitute the ultimate goal of the program. Under the regional haze program, natural conditions need to be estimated for the 20 percent best and worst days.

• Current conditions—Current conditions for the best and worst days are calculated from a multiyear average, based on the most recent years of monitored data. This value would be revised at the time of each periodic SIP revision, and would be used to illustrate: (1) The amount of progress made since the last SIP revision, and (2) the amount of progress made from the baseline period of the program.

Baseline Conditions

Proposed rule. The preamble to the proposal discussed an approach for determining baseline visibility conditions for the haziest 20 percent and clearest 20 percent of days that would allow using a minimum of 3 years of monitored data, and up to a maximum of 9 years of data.

Comments received. The EPA received some comments suggesting that it would be more equitable to use a standardized time period to establish baseline values for all Class I areas across the country. Other commenters supported the use of baseline values based on a varying number of years from site to site. Some commenters also supported the establishment of baseline conditions based on a period of time longer than 3 years because a 3-year period could be significantly influenced by unique meteorological circumstances.

Final rule. After considering public comments on the baseline issue, EPA has determined that the most appropriate ''baseline period'' would be a fixed, 5-year period extending from calendar year 2000 through calendar year 2004. The EPA concluded that a standard baseline period provides for greater national consistency in establishing this important value, and therefore, is preferable to a provision allowing the baseline period to be a variable number of years. Using a common number of years and data points to calculate the baseline value for each site is consistent with fundamental statistical principles and will provide for easy comparison of data from multiple sites as the program is implemented.

The EPA also concluded that it would be preferable to have a baseline value based on more than 3 years in order to establish a more robust baseline value. The EPA agrees with commenters that a 5-year period, rather than a 3-year period, provides for a more stable treatment of the inherent variability in emissions and meteorology. This approach decreases the probability that the baseline period will be unduly affected by unusual or nonrepresentative events.

In deciding upon the specific baseline period of 2000–2004, the Agency took into account the fact that EPA has obtained funding to provide several hundred monitors to the States for the purposes of characterizing $PM_{2.5}$ concentrations in urban and rural areas nationally. In accordance with the part 58 monitoring provision enabling IMPROVE protocol aerosol monitors to be used to characterize $PM_{2.5}$ conditions at background and transport sites, the IMPROVE network will be expanding from 30 to more than 100 sites by the end of 1999 in order to characterize both background $PM_{2.5}$ levels and visibility impairment levels in Class I areas. Thus, EPA concluded that the baseline period should begin in 2000, after monitoring coverage for Class I areas is expanded significantly.

The approach to calculating baseline values will also provide for more stable values because the frequency of monitoring samples in the IMPROVE network will increase in 1999 to one sample every 3 days. In this way, the frequency of sampling for IMPROVE will be consistent with the $PM_{2.5}$ monitoring approach. Thus, annual values should become more robust since 17 percent more samples will be collected each year. Baseline conditions must be determined in terms of deciviews for the years 2000–2004 for the ''most impaired days'' and the ''least impaired days.'' The final rule defines these values as the average of the 20 percent of monitored days with the highest or lowest light extinction values, expressed in deciviews. The EPA will issue guidance for calculating baseline visibility conditions based on ambient monitoring data. The baseline value is determined by calculating the average deciview value for the 20 percent most (or least) impaired days for each of the 5 years (2000 through 2004), and by averaging those five values.

The final rule also calls for baseline conditions to be established by the State for any Class I area without on-site monitoring by using ''representative'' monitoring data for the site. In the SIP, the State will need to provide an adequate demonstration supporting the

[73] National Research Council, Committee on Haze in National Parks and Wilderness Areas, Protecting Visibility in National Parks and Wilderness Areas, National Academy Press, 1993.

use of any ''representative'' data. The EPA will issue guidance to help the States address this issue. The IMPROVE Steering Committee (comprised of representatives from EPA, States, and FLMs) is working to develop acceptable criteria to configure the expanded visibility monitoring network in such a way that virtually all Class I areas will either have an aerosol monitor or will be characterized by a ''representative'' site. The IMPROVE Steering Committee, including State representatives, will complete the process for identifying representative sites before monitoring for the expanded network begins in the year 2000. For this reason, it is expected that most States needing to rely on representative data from another site will be able to meet the requirement of section 51.308(d)(4) by referencing the Visibility Monitoring Guidance Document, which will be released shortly after promulgation of this rule, and other technical support materials developed by the IMPROVE Steering Committee to support the determination of representative sites.

Finally, States that submit SIPs for regional haze by 2003 under section 51.309 (further discussion in unit IV) must determine baseline conditions based on the most recent 5-year period for which monitoring data are available for the Class I area. For an area without monitoring data, the State may use data from another representative Class I area.

Natural Visibility Conditions

Proposal. The proposed rule called for each State having a Class I area, in consultation with the appropriate FLMs, to: (1) Develop a procedure to estimate natural conditions for the 20 percent most impaired and least impaired days at each Class I area within the State; and (2) provide this estimate with the State's first SIP revision for regional haze (in the 2003–2005 timeframe as stated in the proposal). The estimates for natural conditions would be expressed in deciviews. The preamble cited as a default annual average, estimates of natural visibility that were included in the 1991 NAPAP chapter on visibility. When converted to deciview values, these annual average estimates are 9.6 deciviews in the Eastern United States and 5.3 deciviews in the Western United States.

Comments received. A number of commenters noted that there are several factors which can make the determination of natural conditions difficult. For example, organic aerosols resulting from biogenic sources, windblown dust, and natural causes of fire all contribute to natural visibility conditions. Several commenters emphasized the difficulty in determining the estimated contribution of naturally-caused fire to natural conditions. Some commenters suggested that EPA provide guidance on how to estimate natural conditions.

Final rule. The EPA understands that estimating natural visibility conditions can involve many technically complex issues. The EPA is committed to working with the States, tribes, and FLMs on this issue to develop technical guidance on estimating natural visibility conditions. The EPA expects that these estimates may be refined over time. In addition, after the regional haze rule is promulgated, and in advance of SIP due dates, EPA plans to revise the Interim Air Quality Policy on Wildland and Prescribed Fires [74] to address a number of issues, including the contribution of fire to natural visibility conditions.

Consistent with the proposal, the final rule retains the requirement that each State provide an adequate estimate of natural visibility conditions for best and worst visibility days in each Class I area within the State. These estimates will be due at the time the State submits its initial control strategy SIP for regional haze. However, because the requirement for a SIP revision within 12 months of promulgation has been overridden by the provisions of TEA–21, there no longer is a requirement for States to separately submit to EPA recommended procedures for estimating natural conditions in advance of their control strategy SIPs.[75]

The EPA recommends that the States work closely with the FLMs, tribes, and EPA in developing and documenting in their SIPs appropriate methods for estimating natural conditions. Estimates of natural visibility conditions are needed to aid all interested parties, including the general public, in understanding how ''close'' or ''far'' a particular Class I area is in relation to the ultimate goal of the program. Understanding the estimated relative contributions of natural PM constituents (such as organic carbon and crustal material) also can help the States and tribes in understanding the extent of the contribution from manmade components, and thus can help in designing appropriate emission management strategies in the future. With each subsequent SIP revision, the estimates of natural conditions for each Class I area may be reviewed and revised as appropriate as the technical basis for estimates of natural conditions improve.

The EPA believes that, as a starting point, it will be appropriate to derive regional estimates of natural visibility conditions by using estimates of natural levels of visibility-impairing pollutants [76] in conjunction with the IMPROVE methodology for calculating light extinction from measurements of the five main components of fine particle mass (sulfate, nitrate, organic carbon, elemental carbon, and crustal material). By using this approach with appropriate assumptions for annual average relative humidity, EPA estimates natural conditions for the worst visibility days to be approximately 11–12 deciviews in the east and 8 deciviews in the west. The EPA supports use of these estimating techniques as a valid starting point because they rely on peer-reviewed estimates of the natural composition of fine particle mass,[77] and analysis of data from the IMPROVE program's well-established approach, refined over the past 10 years or more, for calculating light extinction from monitored PM constituents.

Because these values are expressed in regional terms only, further refinement of these estimates will need to take place in the future on a site-specific basis. However, because current conditions at most Class I areas with existing IMPROVE monitoring exceed the above estimates by at least several deciviews (with some of the more impaired Class I areas having values that exceed estimated natural conditions by 20 deciviews or more), EPA does not believe that such refined values are necessary for the initial 10-year program implementation period. As the difference between current and natural conditions for a particular Class I area becomes smaller, it will be important to develop more precise techniques for estimating natural conditions.

Current Conditions

Proposal. The proposed rule required the State to revise its long-term strategy every 3 years and to compare current conditions to the visibility conditions existing at the time of its previous long-term strategy revision. Current conditions would be established for the most impaired and least impaired days, and would be expressed in deciviews.

[74] Interim Air Quality Policy on Wildland and Prescribed Fires, U.S. EPA, Office of Air Quality Planning and Standards, May 1998.

[75] See unit III.B. for a detailed discussion of the TEA–21 provisions and their affect on the timing for implementation of the regional haze program.

[76] See National Acid Precipitation Assessment Program. Acid Deposition: State of Science and Technology. Report 24, Visibility: Existing and Historical Conditions—Causes and Effects, Table 24–6. Washington, DC. 1991.

[77] The NAPAP estimates were cited in both the Criteria Document and EPA Staff for the PM NAAQS.

Comments received. Many commenters supported EPA's approach to periodic tracking of changes in visibility to determine reasonable progress. Some commenters felt that averaging 5 years of data, rather than 3, would be preferable.

Final rule. Section 51.308(f)(1) of the final rule retains the requirement for each State, at the time of any SIP revision, to determine the current visibility conditions for the most impaired and least impaired days for each Class I area within the State. Current conditions are to be based on the 5 most recent years of monitoring data available at the time a SIP revision or progress report is submitted. The approach for calculating current conditions is similar to the approach for calculating baseline conditions discussed above: the value is determined by calculating the average for the 20 percent most impaired days for each of the 5 most recent years for which quality-assured data are available, and then by calculating the average of those five values.[78]

Sections 51.308(f)(1) and 51.308(g)(3) of the final rule also require the State to calculate the difference between current conditions and several other parameters so that this information can be taken into account when the State is revising its SIP and considering new reasonable progress goals. A discussion of these calculations is provided in unit III.J of this preamble addressing periodic SIP revisions and progress reports.

Summary

The following summary table further illustrates the uses of ''baseline,'' ''natural,'' and current conditions in the regional haze program.

Term	What does it mean?	How is it used in the regional haze program?
''Baseline conditions''	Visibility (in deciviews) for the 20 percent most-impaired days, and for the 20 percent least-impaired days, for the years 2000 through 2004.	''Baseline'' conditions are used in two ways: (1) For the first regional haze SIPs, due in about 2006–2008, baseline conditions are the reference point against which visibility improvement is tracked. (2) For subsequent SIP updates (in the year 2018 and every 10 years thereafter), baseline conditions are used to calculate progress from the beginning of the regional haze program.
''Natural conditions''	The level of visibility (in deciviews) for the 20 percent most-impaired days, and for the 20 percent least-impaired days, that would exist if there were no manmade impairment..	''Natural conditions'' represents the absence of visibility impairment due to human-caused emissions, the ultimate goal of the regional haze program.
''Current conditions''	''Visibility (in deciviews) for the 20 percent most-impaired days, and for the 20 percent least-impaired days, for the most recent 5-year period.	For the initial planning SIPs, ''current'' and ''baseline'' conditions are the same. For subsequent 5-year progress reports, ''current conditions'' describe the amount of progress that has been made at the mid-course review point halfway through an implementation cycle. For subsequent comprehensive regional haze SIPs (beginning in 2018 and every 10 years thereafter), ''current conditions'' will be used to show how much progress has been made relative to the ''baseline,'' and will serve as the reference point for tracking progress for the next implementation period.

F. Reasonable Progress Goals

The previous section discussed three important visibility parameters for tracking ''reasonable progress'' toward the national visibility goal. In this section, EPA describes the requirements of section 51.308(d)(1) of the final rule for States to establish ''reasonable progress goals'' for each Class I area within the State. In addition, this section also discusses important analyses and other factors for States to take into consideration in setting these goals.

Proposed rule. In the proposed rule, EPA presented a framework for a long-term program under which continued progress would be achieved in Class I areas toward the national visibility goal. The EPA proposed presumptive ''reasonable progress targets,'' expressed in terms of deciviews, for the purposes of improving visibility on the 20 percent worst days and allowing no degradation of visibility on the 20 percent best days. Two options were presented for the presumptive target for the most impaired days: (1) A rate of improvement equivalent to 1.0 deciview over a 10-year period, and (2) a rate of improvement equivalent to 1.0 deciview over a 15-year period. For the least impaired days, EPA proposed a target of no degradation, defined as less than a 0.1 deciview increase.

The EPA noted that the 10- and 15-year time periods for tracking improvement were consistent with section 169A(b)(2)(B), which calls for States to develop long-term strategies covering 10 to 15 years. The EPA also emphasized the importance of achieving a perceptible change in visibility over the time period of a long-term strategy. In addition, EPA stated that gradual improvements in visibility as defined by reasonable progress targets were consistent with the GCVTC definition of reasonable progress, which is ''achieving continuous emissions necessary to reduce existing impairment and attain steady improvement of visibility in mandatory Class I areas.

[78] See the section on Baseline Conditions for a discussion of the rationale for selecting a 5-year period.

* * *'' [79] As noted in unit III.C., EPA also proposed to track progress in relation to the targets through the use of monitored air quality data and calculation of light extinction values from this aerosol data.

The proposal also provided a process by which a State could establish alternate reasonable progress targets, expressed in deciviews, provided the State justified the alternate target based on a review of the relevant statutory factors.[80] These 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 existing source subject to such requirements.

Comments received. A number of commenters advocated a faster rate of improvement than the proposed presumptive rate of 1 deciview every 10 or 15 years since, as proposed, they claimed it could take more than 200 years to reach the national visibility goal in some eastern locations. They felt that this rate of progress should not be considered ''reasonable.'' Many of these commenters supported a rate of improvement for the worst days equal to 10–20 percent of the current deciview value (i.e., 3–6 deciviews per 10 years in an average eastern location with a worst day value of 30 deciviews, and 1.5–3.0 deciviews for an average southwestern location with a worst day value of 15 deciviews). A number of other commenters interpreted the proposed rule as requiring an inflexible visibility ''standard'' of 1 deciview improvement every 10 or 15 years. They maintained that such a standard would be infeasible to achieve in some areas of the country, and that EPA had failed to justify such a presumption through an analysis of the statutory factors in section 169A(g). These commenters wanted the States to have greater flexibility in setting visibility goals. Some commenters stated that 1 deciview is not the threshold of perception in all situations, and that for this reason the one deciview presumptive target in the proposal should be dropped. Other commenters asserted that the no degradation target for the best visibility days would prevent new source growth in some areas. Some commenters also opposed the presumptive target because of the concern that a State could be subject to a citizen lawsuit for not meeting a reasonable progress target.

Final rule. In considering how to address the reasonable progress target issue in the final rule, EPA was mindful of the balance that must be maintained between the need for strategies that will achieve meaningful improvements in air quality and the need to provide appropriate flexibility for States in designing strategies that are responsive to both air quality and economic concerns. After considering the comments on the ''presumptive target'' issue, EPA has revised the rule to eliminate ''presumptive targets.'' There is no presumptive target that States are required to meet to achieve reasonable progress. States have flexibility in determining their reasonable progress goals based on consideration of the statutory factors. However, as discussed below, the final rule requires States to conduct certain analyses to ensure that they consider the possibility of setting an ambitious reasonable progress goal, one that is aimed at reaching natural background conditions in 60 years.

The final rule calls for States to establish ''reasonable progress goals,'' [81] expressed in deciviews, for each Class I area for the purpose of improving visibility on the haziest days and not allowing degradation on the clearest days over the period of each implementation plan or revision. The EPA believes that requiring States to establish such goals is consistent with section 169A of the CAA, which gives EPA broad authority to establish regulations to ''ensure reasonable progress,'' and with section 169B of the CAA, which calls for EPA to establish ''criteria for measuring reasonable progress'' toward the national goal.

This approach is designed to address the concerns of those commenters interested in greater State flexibility in setting visibility goals, as well as the concerns of those commenters who believed that the presumptive 1 deciview target approach could actually provide a disincentive for some States to pursue more ambitious rates of progress, particularly for the most impaired Class I areas in the East. The EPA has taken this approach in the final rule because the CAA national visibility goal and ''reasonable progress'' provisions do not mandate specific rates of progress, but instead call for ''reasonable progress'' toward the ultimate goal of returning to natural background conditions. Today's final rule requires the States to determine the rate of progress for remedying existing impairment that is reasonable, taking into consideration the statutory factors, and informed by input from all stakeholders.

Required analysis of rate of progress which would attain natural conditions in sixty years. The EPA received numerous comments expressing the concern that a rate of progress that would result in reaching the national goal in 200 years should not be considered ''reasonable.'' These comments are based on the fact that the most impaired Eastern United States Class I areas have current conditions for the worst days (around 26–31 deciviews) that exceed estimated natural conditions (approximately 10–12 deciviews) by 16–20 deciviews or more. At the proposed presumptive rate of progress of 1 deciview per 10 years, it would take 200 years or more to reach the national visibility goal in many Eastern Class I areas. In addition, several commenters felt that rates of progress should vary between the east and the west because many parts of the western United States have much lower levels of visibility impairment than the east. For example, they asserted that a 1 deciview improvement over 10 years may not be very ambitious in an eastern location, whereas it could be very ambitious in some of the least impaired Class I areas in the west.

In order to address the diverse concerns of commenters on the proposal, EPA is establishing an analytical requirement that takes into account the varying levels of visibility impairment in Class I areas around the country while ensuring an equitable approach nationwide. To determine an equitable analytical approach, we considered the CAA amendments of 1990, which require actions to attain air quality health standards over a 20-year period for the 1-hour ozone standard, depending on the severity of the area's problem, and over a 10-year period for new standards, such as the new 8-hour ozone standard and the $PM_{2.5}$ standards. The CAA also requires reductions over the same time period to address acid rain. In the eastern United States, EPA's analyses show that the reductions from these and other CAA programs will result in a rate of improvement estimated at approximately 3 deciviews over the period from the mid-1990's to about 2005.[82] The EPA calculated that if this rate of improvement could be sustained, these areas would reach the national goal in 60 years.[83] The EPA

[79] GCVTC Report, June 1996, p. x.

[80] See CA A section 169A(g)(1) and 169A(g)(2). See also 62 FR 41145–41148.

[81] See section 51.308(d)(1).

[82] U.S. EPA, Effects of the 1990 Clean Air Act Amendments on Visibility in Class I Areas: An EPA Report to Congress. Office of Air Quality Planning and Standards, EPA–452/R–93–014, 1993.

[83] Calculated by dividing 3 deciviews (per 10 years) into an average of 18 deciviews away from

Continued

concluded that it would be reasonable to establish an analytical requirement based on this rate of progress given that this rate of improvement is expected to be achieved due to emissions under CAA programs.

The EPA also believes that the analytical requirement of the rate of improvement needed to reach natural conditions in 60 years is reasonable because in the near-term, cost-effective controls will continue to be available to reduce emissions that contribute to visibility impairment in Class I areas across the country. Recent analyses for other air quality programs show that significant emissions can be achieved through cost-effective control measures.

In addition, in the longer term, it can be expected that continued progress in visibility will be possible as industrial facilities built in the latter half of the 20th century reach the end of their ''useful lives'' and are retired and/or replaced by cleaner, more fuel-efficient facilities. Significant improvements in pollution prevention techniques, emissions control technologies, and renewable energy have been made over the past 30 years, and continue to be made. History strongly suggests that further innovations in control technologies are likely to continue in future decades, leading to the ability of new plants to meet lower emissions rates.

In light of this analysis of progress that could potentially be achieved, EPA has established in section 51.308(d)(1)(i)(B) an analytical requirement for setting reasonable progress goals that should provide for greater equity between goals set for the more impaired Eastern United States and the less impaired Western United States. This analytical requirement has the following four steps.

First, the State (or regional planning group) must compare the baseline visibility conditions in the years 2000–2004 (in deciviews) for the most impaired days with the natural background conditions, for each relevant Class I area. From this comparison, the State must determine the amount of progress needed to reach natural background conditions in 60 years, that is, by the year 2064. For example, if the baseline visibility is 30 deciviews, and the natural background is 12 deciviews, then this step would show the need for an 18 deciview improvement between 2004 and 2064.

Second, the State must identify the uniform rate of progress over the 60 year period that would be needed to attain natural background conditions by the year 2064. For the example case noted above, where 18 deciviews is the amount for the 60-year period, this would result in a uniform rate of progress for each year of (18/60), or 0.3 deciviews for a year.

Third, the State must identify the amount of progress that would result if this uniform rate of progress were achieved during the period of the first regional haze implementation plan. For example, if the first implementation plan covers a 10-year period, then for the above example, the State would identify a 3 deciview amount of progress over that time period.

Fourth, the State must identify and analyze the emissions measures that would be needed to achieve this amount of progress during the period covered by the first long-term strategy, and to determine whether those measures are reasonable based on the statutory factors. These factors are the costs of compliance with the measures, the time necessary for compliance with the measures, the energy and nonair quality environmental impacts of the compliance with the measures, and the remaining useful life of any existing source subject to the measures.

In doing this analysis, the State must consult with other States which are anticipated to contribute to visibility impairment in the Class I area under consideration. Because haze is a regional problem, States are encouraged to work together to develop acceptable approaches for addressing visibility problems to which they jointly contribute. If a contributing State cannot agree with the State establishing the reasonable progress goal, the State setting the goal must describe the actions taken to resolve the disagreement.

If the State determines that the amount of progress identified through the analysis is reasonable based upon the statutory factors, the State should identify this amount of progress as its reasonable progress goal for the first long-term strategy, unless it determines that additional progress beyond this amount is also reasonable. If the State determines that additional progress is reasonable based on the statutory factors, the State should adopt that amount of progress as its goal for the first long-term strategy.

If the State determines, based on the statutory factors, that the identified uniform rate of progress needed to reach natural conditions is not reasonable, the State must provide in its plan submission the analysis and rationale supporting this determination. The State then must provide a demonstration as part of its SIP submission showing why a less ambitious goal is reasonable, based on the statutory factors. The EPA intends to issue guidance interpreting the statutory factors and providing examples of ways in which they may be applied.

The State must also provide to the public, in accordance with section 51.308(d)(1)(ii), an assessment of the number of years it would take to reach natural conditions if the State continued to make progress at the alternative rate of progress it selected. For example, if average worst day visibility at the class I area is 18 deciviews from estimated natural conditions, the uniform rate of progress needed to reach natural conditions is 3 deciviews per 10 years. If the State determined that 3 deciviews is not reasonable but 2 deciviews is, then the State would have to include a statement in its SIP that it would take 90 years to reach natural conditions if this rate is maintained.

It should be noted that in developing the first regional haze implementation plan (and subsequent revisions), there is a time period of several years between the time period for which data are available and the date of plan submission. The first regional haze implementation plans for most of the United States will use the years 2000 through 2004 as the baseline for monitoring and emission inventories, while the first implementation plan for much of the country will not be due until a deadline that occurs between 2006 to 2008. In identifying the amount of progress needed by the end of the implementation period (the third step described above), States must account for this time period. Assume, for example, for the case discussed above (i.e., a 30 deciview baseline, and a uniform rate of progress of 0.3 deciviews per year to reach natural conditions in 60 years) that the first regional haze SIPs covers the years 2009 through the year 2018. For this case, there would thus be a 4-year period (2005 through 2008) that would occur between the baseline and the date of SIP submission. The uniform rate of progress of 0.3 deciviews per year over this time period would result in 1.2 deciviews of improvement before the plan submission. Hence, for this example, in identifying the amount of progress needed between the baseline and the end of the implementation period (i.e., the year 2018), the State must evaluate strategies that provide for a total of 4.2 deciviews: 1.2 deciviews between the last year of the baseline period and plan submission, and 3 deciviews for the implementation

natural conditions, and multiplying 6 increments by 10 years, assuming 10 years to achieve each increment.

period. The effect of this provision is that States must be mindful of the expected activities that take place before plan submission. Generally, we expect for the first plan submission period that progress in visibility improvement will continue to occur during the 2004 to 2008 period due to implementation of other CAA programs.

Rationale for the required 60-year analysis. The EPA has adopted this analytical requirement for two reasons. First, a common analytical framework that recognizes regional differences meets the concerns of several commenters by providing greater equity between the Eastern United States and Western United States.

Second, EPA believes this analysis will provide important additional information for the public to consider as States establish progress goals. The EPA believes this analysis will provide for a more informed and equitable decision making process by giving the public information about the level of emissions needed, related costs, and other factors associated with improvements in visibility. The EPA recommends that as part of this process, the States use computer-based scene optics modeling tools to present to the general public the anticipated change in Class I area visibility that would result from one reasonable progress goal versus another.

Consideration of other CAA measures. In determining the emissions and visibility improvement achieved during each implementation period, States should include all air quality improvements that will be achieved by other programs and activities under the CAA and any State air pollution control requirements. Therefore, any reasonable progress goal for a Class I area should reflect at least the rate of visibility improvement expected from the implementation of other ''applicable requirements'' under the CAA during the period covered by the long-term strategy. Consequently, States must take into account, at a minimum, the effect of measures to meet the NAAQS, the national mobile source program, and other applicable requirements under the CAA on Class I area visibility.

While, as noted above, based on our current understanding, EPA expects in the eastern United States that the reductions from measures implementing the CAA requirements will provide the visibility improvement and emissions needed for reasonable progress during the first regional haze implementation plan, EPA also recognizes that States will not be submitting their regional haze plans for several years. In developing its submittal, each State will need to conduct analyses to support its reasonable progress goals according to information available at the time the plan is submitted about benefits from the existing CAA programs. Each State should set its goal(s) taking into consideration input from its stakeholders and based on the statutory factors described above. In addition, the State must also conduct a BART determination for each source subject to BART as required in section 51.308(e) of the rule and described in section III.H. of the preamble. In considering whether reasonable progress will continue to be maintained, States will need to consider during each new SIP revision cycle whether additional control measures for improving visibility may be needed to make reasonable progress based on the statutory factors.

Some commenters expressed concern that the State would be subject to sanctions or enforcement actions in the event that a State fails to meet a reasonable progress target. As noted above, the reasonable progress goal is a *goal* and not a mandatory standard which must be achieved by a particular date as is the case with the NAAQS. Once a State has adopted a reasonable progress goal and determined what progress will be made toward that goal over a 10-year period, the goal itself is not enforceable. All that is ''enforceable'' is the set of control measures which the State has adopted to meet that goal. If the State's strategies have been implemented but the State has not met its reasonable progress goal, the State could either: (1) revise its strategies in the SIP for the next long-term strategy period to meet its goal, or (2) revise the reasonable progress goals for the next implementation period. In either case, the State would be required to base its decisions on appropriate analyses of the statutory factors included in section 51.308(d)(1)(i)(A) and (B) of the final rule.

If a State fails to submit an approvable SIP, or if it fails to implement and enforce strategies adopted into its SIP, the State could be subject to sanctions under the CAA. If the State continues to fail in meeting its obligations, EPA could be required to develop and implement a Federal implementation plan (FIP).

Allowing no degradation for the best days. Some commenters supported the goal of no degradation at a minimum, but they asserted that in many Class I areas, particularly in the east, the ''best days'' are in fact still quite impaired. In their view, a rule requiring only preservation of existing clean days would not meet the national goal.[84] Other commenters stated that a ''no degradation'' target for the clearest days could result in limitations to economic growth.

The final rule maintains the approach used in the proposed rule, which established a goal of no degradation for the best visibility days. The EPA believes this approach is consistent with the national goal in that it is designed to prevent future impairment, a fundamental concept of section 169A of the CAA. The EPA recognizes that the best days are still impaired in many Class I area locations, particularly in the east. The EPA encourages States to evaluate monitoring data to determine whether the same types of sources are affecting both the clear days and the hazy days. If the relative contribution of different particle types to light extinction is similar for both clear and hazy days, as it is for many sites currently monitored, then by developing strategies to improve conditions on the worst visibility days, the States will likely improve the entire distribution of hazy and clear days. Thus, under the final rule, the clean days for most Class I areas are expected to improve over time. Indeed, recent analyses of visibility trends have shown that at many Class I areas, deciview values for the 20 percent least impaired days are declining.

If at a Class I area the average conditions for clear days degrades over time, the State must provide in the next plan revision an explanation of why this happened, a set of measures designed to reverse this trend, and a plan for implementation during the next 10-year period. The State should review the effectiveness of these measures in subsequent 5-year progress reviews.

Integral vistas. The scenic vistas enjoyed by visitors to many parks often extend to important natural features outside these parks. The 1980 rules included a provision whereby the States could identify specific vistas for protection. For this reason, EPA solicited comment on whether the integral vistas concept should be extended to the regional haze program.

Some commenters supported reopening the vista identification program because such vistas are a significant resource of a Class I area. Several others opposed extending the program for a variety of reasons.

[84] Data from the IMPROVE network show that for several sites in the Eastern United States, the deciview values for the best days are greater than 14 deciviews, which is higher than even the NAPAP estimate of annual average conditions in the Eastern United States (9.6 deciviews).

The final regional haze rule does not extend the integral vista concept to the regional haze program. As noted earlier in the background section of this preamble, regional haze is caused by a multitude of sources across a broad geographic area, and it can create a uniform haze in all directions. The regional haze program is designed to bring about improvements in regional visibility for the range of possible views of sky and terrain found in any Class I area. Accordingly, the program does not protect only specific views from a Class I area. To address haze, regional strategies will be needed, and emissions resulting from these strategies are expected to improve visibility across a broad region, not just within a Class I area. Thus, although the regional haze program does not include a specific provision regarding integral vistas, the long-term strategies developed to meet reasonable progress goals would also serve to improve scenic vistas viewed from and within Class I areas.

Use of 20 percent most-impaired days and 20 percent least-impaired days. The final rule maintains the approach discussed in the proposal of improving the most-impaired visibility days (i.e., the average of the 20 percent most impaired days over an entire year), and allowing no degradation in the ''cleanest'' or least impaired days (i.e., the average of the 20 percent least impaired days over an entire year). In deciding upon an appropriate characterization of the ''most'' and ''least'' impaired days, EPA considered the typical frequency of aerosol monitoring in the IMPROVE network [85] (once every 3 days), and the number of samples that would be available for analysis annually (122 possible samples per year). The EPA believes that calculating annual ''best'' and ''worst'' conditions on the basis of an average of the 20 percent best and worst visibility days represents a reasonable approach to characterizing the typical best and worst conditions without having these values unduly influenced by a single anomalous data point.

The EPA's basis for maintaining the proposed approach is supported by the CAA and its legislative history, and by the approach used by the GCVTC in its technical assessment work and in its definition of reasonable progress. The EPA believes that a rule that requires strategies for improving the worst days and allowing no degradation on the clean days is consistent with the national visibility goal in section 169A of the CAA, which calls for preventing any future impairment (protecting clearest days) and remedying any existing impairment (improving the already impaired days). This approach is also supported by the legislative history of the 1990 CAA and the reasonable progress definition. The legislative history provides that, ''At a minimum, progress and improvement must require that visibility be perceptibly improved compared to periods of impairment, and that it not be degraded or impaired during conditions that historically contribute to relatively unimpaired visibility.'' [86] The GCVTC interpreted ''reasonable progress'' to be ''achieving continuous emissions reductions necessary to reduce existing impairment and attain a steady improvement in visibility in mandatory Class I areas, and managing emissions growth so as to prevent perceptible degradation of clear air days.'' [87] In today's final rule, EPA is similarly providing for ''attaining a steady improvement in visibility'' and ''preventing degradation of clean air days'' through the requirement to improve the haziest days and prevent degradation of the clearest days.

Tracking progress based on 5-year averages. To determine whether reasonable progress in improving visibility is being achieved, States will need to collect and analyze air quality data each year and review progress at 5-year intervals. Because the regional haze program represents a long-term effort to improve visibility in Class I areas, EPA believes that monitoring and assessments of progress should not be unduly influenced by short-term events or unusual meteorological conditions, but should reflect trends in air quality which are robust and insensitive to minor fluctuations. For this reason, the final rule calls for measuring progress by tracking changes in 5-year average deciview values for the haziest and clearest days, and comparing these current conditions against baseline conditions as well as impairment levels at the time of the last SIP revision. (See unit III.E above for further discussion about establishing baseline and current conditions based on 5-year averages.)

G. Long-Term Strategy

Proposed rule. Under Section 169A(b)(2) of the CAA, EPA's visibility regulations must require States to include in their SIPs ''such emission limitations schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal specified in * * * [section 169A(a)] * * *'' In section 169A(b)(2)(B), the CAA requires that these SIPs must include a ''long-term (ten to fifteen years) strategy for making reasonable progress toward meeting the national goal.'' The EPA interprets the term ''long-term strategy'' as the control measures that are needed to ensure reasonable progress, together with a demonstration that those measures will provide for reasonable progress during the 10 to 15 year period. The proposed rule required the State to develop a long-term strategy for regional haze with the initial regional haze SIP, and to provide for regular updates. (Issues regarding updates of the long-term strategy are discussed below in unit III.J).

The proposal also required States to consider a specific list of factors when they developed their long-term strategies for regional haze. Under the proposal, in developing long-term strategies for regional haze, States would be required to consider the six items listed in section 51.306(e) of the 1980 rule, and the five items listed in section 51.306(g) of the 1980 rule. We proposed to add a seventh item to section 51.306(e), ''the anticipated effect on visibility due to projected changes in point, area and mobile source emissions over the next 10 years.''

Comments received. Public commenters on the long-term strategy requirement expressed concerns that the proposed rule had over-emphasized stationary source contributions, and had under-emphasized contributions from minor sources, area sources, mobile sources and prescribed fires. Other commenters expressed concerns that control strategies would be ineffective in cases where contributions from international sources were causing visibility impairment. Commenters also emphasized that States be able to take credit in their long-term strategies for the effects of existing CAA programs. We did not receive any comments on the specific list of factors to consider in developing long-term strategies.

Final rule. As discussed further below in unit III.J of today's notice, the final rule requires control strategies to cover an initial implementation period extending to the year 2018, with a reassessment and revision of those strategies, as appropriate, every 10 years. The final rule, in section 51.308(d)(3), includes a requirement for regional haze SIPs to include a long-term strategy. The long-term strategy must include specific enforceable measures that are sufficient to meet the ''reasonable progress goals'' for all Class

[85] The IMPROVE network is described in unit III.I. of the preamble.

[86] 136 Cong. Rec. S2878 (daily ed. March 21, 1990) (statement of Sen. Adams).

[87] GCVTC Report, p. x.

I areas affected by emissions from the State.

Multistate contributions—requirements for consultation and apportionment. As noted in section 51.308(d)(3)(i), when a State's emissions are reasonably anticipated to cause or contribute to impairment in a Class I area located in another State or States, the rule requires that the State consult with the other State or States in order to develop coordinated emission management strategies. Regarding the Class I areas within the State, section 51.308(d)(3)(i) also requires States to consult with any other State having emissions that are reasonably anticipated to contribute to impairment in any Class I area within the State.

For Class I areas where the State and other States cause or contribute to impairment in a mandatory Class I area, section 51.308(d)(3)(ii) requires that the State must demonstrate that it has included in its implementation plan all measures necessary to obtain its share of the emissions needed to meet the progress goal for the area. Section 51.308(d)(3)(iii) requires that States must document the technical basis, including modeling, monitoring and emissions information, that it uses to determine its apportionment of emission reduction obligations for the Class I areas the State affects. It is important that EPA and stakeholders understand the modeling, monitoring and emission information that the State used to support its conclusion that the long-term strategy provides for reasonable progress.

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

Consideration of all anthropogenic sources. In the final rule, we have clarified in section 51.308(d)(3)(iv) that the State should consider all types of anthropogenic sources including stationary, minor, mobile, and area sources in developing its long-term strategy. The State should review all such sources in identifying the emission reduction measures to be included in the strategy. In addition, we provide the following points of clarification:

Minor sources. Because of the focus of the BART provision on major stationary sources, EPA believes that commenters may have the impression that EPA has concluded that minor sources with emissions, below the BART cutoff of 250 tons per year, are not significant contributors to regional haze. This is not the case. The EPA believes that States should take the cumulative emissions from minor sources into account in developing their regional haze long-term strategies. For example, if growth in minor source emissions for a particular category had a substantial impact on emission trends and a corresponding effect on regional haze in a given geographic area, States should consider emission control strategies for such source categories as part of their long-term strategies.

Mobile sources. In cases where pollutants emitted by mobile sources contribute to regional haze, States must include in their SIPs mobile source emissions inventories representing current conditions, as well as comparisons of those emissions with future emissions projected for the end of the covered by the long-term strategy. It will be particularly important for States to address the effects of population growth and accompanying increases in vehicle miles traveled on their ability to provide for reasonable progress. The EPA agrees with commenters that national mobile source emission standards also will be an important factor in projecting mobile source emissions. The EPA intends to support States in their efforts to estimate mobile source emissions (including the effects of Federal rules) of pollutants that lead to regional haze.

Area sources. States also need to develop emission inventories and conduct analyses to understand the importance of area sources. For example, the GCVTC report cited emissions from road dust as a possible contributor to impairment. Depending on the nature of the visibility problem, road dust and other area sources may at times make a significant contribution to visibility impairment. States should include area sources in emission inventories and control strategy analyses as warranted.

Fire. Commenters expressed a number of concerns with respect to the appropriate consideration of emissions from fire in the development of long-term strategies.

The EPA notes that fire emissions have both a natural and a manmade component. In addressing fire emissions in long-term strategies, EPA believes that States must take into account the degree to which fire emissions cause or contribute to ''manmade'' visibility impairment and its contribution to natural background conditions. Reducing ''manmade'' visibility impairment is the focus of sections 169A and 169B of the CAA. The EPA recognizes the natural role of fire in forest ecosystems, and the fact that forest fuels have built up over many years due to past management practices designed to protect public health and safety through fire suppression. Research has shown that these practices have led to an increased risk of catastrophic wildfire as well as reduced forest health. In response to this situation, the Federal land management agencies, as well as some States and private landowners, have recommended the increased use of prescribed fire in order to return certain forest ecosystems to a more natural fire cycle and to reduce the risk of adverse health and environmental impacts due to catastrophic wildfire.

The EPA also recognizes that fire of all kinds (wildfire, prescribed fire, etc.) contributes to regional haze, and that there is a complex relationship between what is considered a natural source of fire versus a human-caused source of fire. For example, the increased use of prescribed fire in some ecosystems may lead to PM emissions levels lower than those that would be expected from catastrophic wildfire. Given that the purpose of prescribed fire in many instances is to restore natural fire cycles to forest ecosystems, it would be appropriate to consider some portion of prescribed fire as ''natural.'' Consequently, in determining natural background for a Class I area, EPA believes States should be permitted to consider some amount of fire in the calculation to reflect the fact that some prescribed fire effects serve merely to offset what would be expected to occur naturally. The EPA will work with the FLMs, States and other stakeholders to develop guidance on ways in which fire can be considered in the determination of natural background, and in the determination baseline and current conditions.

Commenters asserted that in the proposed rule, EPA ignored the contribution of fires and thus overlooked the most important haze-contributing emission source in many Class I areas. The EPA agrees that fire is an important emission source to include in the analysis, but current data do not show that fire is the predominant source of visibility impairment in any Class I area. Annual data from the IMPROVE network show that elemental carbon (which we generally use as the main indicator of emissions from fire and other combustion sources such as diesel emissions), accounts for only about 3–7 percent of $PM_{2.5}$ mass on the worst visibility days in eastern sites. In western sites, elemental carbon accounts for about 4–7 percent of total $PM_{2.5}$ mass on the worst days. The contribution from fires can be substantial over short-term periods, but fires occur relatively infrequently and thus have a lower contribution to long-term averages. Fire events making substantial contributions to haze in a given Class I area have occurred relatively infrequently, and as a practical matter will contribute less than sources for which emissions are more continuous. As noted previously, the final rule requires States to develop long-term strategies for regional haze that address 5-year averages of the 20 percent worst days. These 5-year averages will also be used in evaluating monitoring results. The frequency with which fires occur will effect the importance of their emissions on predicted future 5-year averages for visibility conditions on the 20 percent worst days.

Commenters expressed concerns with the expected increase in emissions from prescribed burning on Federal lands. Specifically, the commenters asserted that States would not be able to address emission increases from these prescribed burns, and that stationary sources would be required to compensate for the increased amount.

The EPA believes these commenters are mistaken in their view of State's authority to address emissions from prescribed Federal burns. Pursuant to section 118 of the CAA, when States impose requirements on sources, Federal agencies must comply with those requirements in the same manner, and to the same extent, as any nongovernmental entity. States therefore have the authority to address emissions from prescribed Federal burns in the same manner, and to the same extent, they regulate prescribed fires generally. Additionally, to the degree that States determine in the development of long-range strategies that the manmade component of fire is a significant contributor to regional haze, States have a substantial degree of flexibility under the CAA and in the final rule. The final rule provides States flexibility in determining the amount of progress that is ''reasonable'' in light of the statutory factors, and also provides flexibility to determine the best mix of strategies to meet the reasonable progress goal they select. Nothing in the final rule requires States to develop long-term strategies that reduce emissions from other sources by amounts equivalent to any increases from the manmade fraction of prescribed fires. We do expect that States consider and analyze the full range of available control measures and that they consider the causes of visibility impairment when evaluating the potential measures to include in their long-term strategies.

The EPA encourages the development of smoke management programs between air regulators and land managers as a means to manage the impacts of wildland and prescribed burning. The sources of information described above, as well as other developmental efforts currently underway, provide effective, flexible approaches to smoke management. Where smoke impacts from fire are identified as an important contributor to regional haze, smoke management programs should be a key component of regional and State regional haze planning efforts and long-term strategies.

There are a number of sources of information on mitigation approaches for fire emissions, including: (1) The EPA Interim Air Quality Policy on Wildland and Prescribed Burning, (2) fire-related strategies developed by the GCVTC and (3) the best available control methods (BACM) document for prescribed burning. In the Interim Air Quality Policy on Wildland and Prescribed Burning, EPA, in collaboration with a national stakeholder group comprised of Federal, State, and private land managers, State air regulators, environmental groups, tribes, and others, developed a framework for managing the impacts of smoke from increased prescribed fire programs across the country. This policy describes the elements and process of smoke management planning that air regulators and land managers can use to reach agreement on development of smoke programs. The GCVTC included a number of long-term strategies for fire in its report and recommendations, including emissions tracking and emission goals for fire, smoke management programs, and full consideration for alternatives to fire. The GCVTC's strategy is illustrative of the available mitigation approaches for emissions from fire that other States may consider. The GCVTC's approach is contained in section 51.309(d)(6) of the final rule and discussed further in unit IV.C of this notice. The BACM document, Prescribed Burning Background Document and Technical Information Document, EPA–450/2–92–003, is organized to discuss various aspects of State smoke management programs. The document includes information on how States administer and enforce programs for burn/no-burn days, and information on various topics including emission inventories, cost estimation, and public information programs.

Transboundary emissions from sources outside the United States. Some Class I areas located near international borders are particularly prone to influence by emissions beyond the United States border. Commenters expressed concerns that EPA should take into account that States are not able to control international sources in reviewing a State's proposal for a reasonable progress target. Additionally, commenters urged EPA to work with Mexico and Canada to reduce emissions from sources that States determine to be significant contributors to regional haze in their Class I areas.

The EPA agrees that the projected emissions from international sources will in some cases affect the ability of States to meet reasonable progress goals. The EPA does not expect States to restrict emissions from domestic sources to offset the impacts of international transport of pollution. We believe that States should evaluate the impacts of current and projected emissions from international sources in their regional haze programs, particularly in cases where it has already been well documented that such sources are important. At the same time, EPA will work with the governments of Canada and Mexico to seek cooperative solutions on transboundary pollution problems.

Factors to consider for long-term strategies. In section 51.308(d)(3)(v) (A) through (G) in the final rule, we have incorporated a list of seven factors that States must consider in developing long-term strategies. The final rule includes six factors in the July 1997 proposal that are derived from section 51.306(e) of the existing rule, and the additional item, ''the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy'' that was specifically added by the July 1997 proposal. We have decided not to include the five proposed items that are derived from section 51.306(g), because four of these items are included on the list of ''reasonable progress'' factors in section 51.308(d)(1)(i)(A) of the final rule, and because we believe that the fifth factor ''effect of new sources'' is part of ''projected changes in point source emissions.''

In their regional haze SIP submissions, States must describe how each of these seven factors is taken into account in developing long-term strategies. We believe it is useful to clarify several of these factors, and EPA's expectations on how SIPs can address them.

Item (A): Emissions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment.

It is expected that for some areas of the country, such as parts of the eastern United States, emissions achieved for the acid rain program and for meeting the $PM_{2.5}$ NAAQS, will lead to substantial improvements in visibility as well. Item (A) makes clear that States must take these other emissions into account in developing their long-term strategies for regional haze. We expect that some States may be able to demonstrate reasonable progress based on these emissions alone, particularly for the first 10-year period.

Item (B): Measures to mitigate the impacts of construction activities.

Item (B) requires that in developing long-term strategies, States must consider the impacts of construction activities. States, for example, should include these activities in emission inventories used for long-term strategy development.

Item (C): Additional measures and limitations and schedules for compliance to achieve the reasonable progress goal.

Where emissions from ongoing requirements, addressed by item (A), are not sufficient to achieve the reasonable progress goal, States must identify additional measures that will ensure that the goal will be met. Schedules for compliance for these additional measures must be included in the SIP, and measures considered for inclusion must be identified in the SIP submission.

Item (D): Source retirement and replacement schedules.

Item (D) requires the consideration of source retirement and replacement schedules in developing the long-term strategies, particularly, where these schedules would have a significant impact on regional emission loadings and on a State's ability to achieve reasonable progress.

Item (E): Smoke management techniques for agricultural and forestry management purposes including plans as they currently exist within the State for these purposes.

Item (E) highlights the widely recognized importance of prescribed burning programs on regional haze. Issues related to fire and forestry management practices are discussed above.

Item (F): Enforceability of emissions limitations and control measures.

States must ensure that control measures are written in a way that EPA and citizens may enforce as a practical matter. Guidance on practical enforceability issues is readily available in EPA policy guidance memoranda, for example Guidance on Limiting Potential to Emit in New Source Permitting, June 13, 1989.

Item (G): The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the next 10 years.

Item (G) requires that States must address the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the next 10 years when developing emissions strategies that will meet the reasonable progress requirements. In some areas, these changes in emissions would be expected primarily from population growth, while in others, emissions changes may result from potential new industrial, energy, natural resource development, or land management activities. These changes in emissions would also include the changes due to measures developed specifically for the regional haze program.

Relationship to long-term strategies under the existing rule. The final rule provides for coordination of the long-term strategies to address regional haze impairment with any existing long-term strategies under the 1980 visibility rule. Some long-term strategies are already in place to address reasonably attributable visibility impairment under the existing 1980 regulation. Coordination of the two programs is addressed in section 51.306(c) of the final rule. This section clarifies two points. First, that the provisions of existing long-term strategies will continue to apply until regional haze strategies are in place. Second, once the first regional haze strategy is in place, the final rule, in section 51.306(c) requires the State to develop a coordinated long-term strategy which address both reasonably attributable impairment and regional haze.

H. Best Available Retrofit Technology (BART)

Background. One of the principal elements of the visibility protection provisions of the CAA is the provision in section 169A addressing the installation of BART for certain existing sources. The conference committee report accompanying the 1977 CAA amendments indicates that a major concern motivating the adoption of the visibility provisions was ''the need to remedy existing pollution in the Federal mandatory class I areas from existing sources.''[88] The BART provision in section 169A(b)(2)(A) demonstrates Congress' intention to focus attention directly on the problem of pollution from a specific set of existing sources. This provision provides that EPA's regulations to protect visibility must require States to revise their SIPs to contain such measures as may be necessary to make reasonable progress toward the national visibility goal, including a requirement that certain existing stationary sources procure, install, and operate the ''best available retrofit technology.''

The CAA defines the sources potentially subject to BART as major stationary sources, including reconstructed sources, from one of 26 identified source categories which have the potential to emit 250 tons per year or more of any air pollutant, and which were placed into operation between August 1962 and August 1977.[89] This set of sources potentially subject to BART was defined in the 1977 CAA and will not be modified by rule. The 26 source categories are:

(1) Fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input,

(2) Coal cleaning plants (thermal dryers),

(3) Kraft pulp mills,

(4) Portland cement plants,

(5) Primary zinc smelters,

(6) Iron and steel mill plants,

(7) Primary aluminum ore reduction plants,

(8) Primary copper smelters,

(9) Municipal incinerators capable of charging more than 250 tons of refuse per day,

[88] H.R. Rep. No. 564, 95th Cong., 1st Sess. at 155 (1977) (emphasis added).

[89] See CAA sections 169A (b)(2)(A) & (g)(7).

(10) Hydrofluoric, sulfuric, and nitric acid plants,
(11) Petroleum refineries,
(12) Lime plants,
(13) Phosphate rock processing plants,
(14) Coke oven batteries,
(15) Sulfur recovery plants,
(16) Carbon black plants (furnace process),
(17) Primary lead smelters,
(18) Fuel conversion plants,
(19) Sintering plants,
(20) Secondary metal production facilities,
(21) Chemical process plants,
(22) Fossil-fuel boilers of more than 250 million British thermal units per hour heat input,
(23) Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels,
(24) Taconite ore processing facilities,
(25) Glass fiber processing plants, and
(26) Charcoal production facilities.

In section 51.301(e) of the 1980 visibility regulations, a source meeting the above criteria was defined as an ''existing stationary facility.'' In today's regional haze rule, EPA has added the definition of a ''BART-eligible source'' in section 51.301(hh) that is identical to the definition of ''existing stationary facility.'' This new definition is used throughout the regional haze rule and preamble in order to avoid the potential misinterpretation of the ''existing stationary facility'' definition as representing a collection of sources broader than the subset of sources potentially subject to BART.

The regulations issued in 1980 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 a BART eligible facility.[90] The BART emission limitation must be established, on a case-by-case basis, taking into consideration the following factors:

- The technology available,
- The costs of compliance,
- The energy and nonair environmental impacts of compliance,
- Any pollution control equipment in use at the source,
- The remaining useful life of the source, and
- The degree of improvement in visibility which may reasonably be anticipated from the use of such technology.[91]

The EPA published guidelines in 1980 which outline the general procedures for States to follow in analyzing sources and establishing BART emission limits.[92] These guidelines apply to situations in which visibility impairment in the Class I area is determined to be ''reasonably attributable'' to a single source or a small group of sources.

Proposed rule. The proposed regional haze rule discussed a process for addressing BART in the context of regional haze and requested comment on how the requirement should be implemented. The first step in this process was a requirement that the State identify all sources potentially subject to BART early in the planning process. The second step required the State to submit a plan and schedule for evaluating BART and the corresponding potential emissions for those existing sources which may reasonably be anticipated to contribute to regional haze visibility impairment. The notice proposed to provide 3 years for completing this evaluation so that the results could be taken into consideration by States as they develop coordinated strategies for attaining the $PM_{2.5}$ and ozone NAAQS.

In setting out the proposed approach to the BART requirement, EPA proposed that the test for determining whether a BART-eligible source ''may reasonably be anticipated to contribute'' to regional haze should be evaluated in the context of the overall emissions reduction strategy. The EPA also noted that it believed that a similar approach should be taken in addressing ''the degree of improvement in visibility which may reasonably be anticipated'' from the imposition of BART controls. The EPA proposed a cumulative approach because of the nature of the regional haze problem (i.e., the cumulative product of emissions from many sources over a broad area) and because of the time and expense necessary to try to determine, one source at a time, the percentage contribution of each BART-eligible source to regional haze. In addition, EPA noted the substantial technical difficulties associated with estimating the degree of visibility improvement resulting from a single source. The EPA broadly requested comments on effective approaches for States and sources to meet the BART requirement under the regional haze program in the most appropriate manner, and in particular how BART, once determined, should be implemented.

Comments received. Commenters identified a number of issues concerning how EPA should address the BART requirement under the regional haze program. Some commenters asserted that the BART requirement simply should not apply under the regional haze program. These commenters argued that the procurement, installation, and operation of BART is not explicitly required under section 169B, and that section 169B is the primary statutory authority for the regional haze program. Other opponents of the BART requirement contended that the proposal placed too much emphasis on stationary sources, and on BART sources in particular, as opposed to other sources of visibility-impairing pollutant emissions, such as mobile and area sources. The commenters contended that BART should not be the principal control strategy employed under the regional haze program.

Another group of commenters supported EPA's proposed approach for addressing the BART requirement. Some pointed out that while existing stationary sources are not the only contributors to regional haze, controlling these sources is an essential element of a national regional haze program. These commenters also supported the approach of evaluating BART-eligible sources collectively to determine their overall contribution to visibility impairment within a given airshed. Several commenters recommended that BART be equivalent to, or more stringent than, new source performance standards (NSPS) for sulfur dioxide and nitrogen oxides. Some commenters suggested allowing an emissions cap-and-trade program to meet the BART requirement. One commenter described a process whereby States would conduct an assessment of the availability of retrofit controls for all BART-eligible sources in a region, calculate the cumulative emissions possible from application of BART to eligible sources, establish a cap for each visibility-reducing pollutant, and implement a 10-year program to achieve emissions equivalent to the emissions cap.

Response to comments. The EPA disagrees with the commenters who argued that the BART requirements should not apply to the regional haze program. The statutory authority for developing a regional haze program emanates from section 169A of the CAA, and any SIPs that are to be developed under a regional haze program must include provisions that meet the requirements of this section, including the requirement that certain sources procure, install, and operate BART.

[90] Section 51.301(c).

[91] *Id.*

[92] See EPA, Office of Air Quality Planning and Standards, Guidelines for Determining Best Available Retrofit Technology for Coal-Fired Power Plants and Other Existing Stationary Facilities, EPA–450/3–80–009b, November 1980.

Since 1977, section 169A of the CAA has authorized EPA to address regional haze. Section 169A(a)(1) of the CAA establishes as the national visibility protection goal ''the prevention of any future, and the remedying of any existing, impairment of visibility in Class I areas which impairment results from manmade air pollution.'' Visibility impairment is defined broadly in the CAA and includes that caused by regional haze.[93] This language does not distinguish between reasonably attributable impairment and regional haze, but provides for visibility protection generally. This reading of the statute is consistent with the legislative history; in adopting section 169A, Congress evinced its intent to address impairment caused by ''hazes'' and the potential corresponding need to control a ''variety of sources'' and ''regionally distributed sources.'' [94] While EPA deferred addressing regional haze in 1980 when it promulgated the first phase of visibility regulations, it did so because of technical obstacles, not because of a limitation on its legal authority.[95] Indeed, in the 1980 rule, EPA expressed its intent to address regional haze in a future rulemaking under section 169A. Thus, EPA's decision to address visibility impairment in separate phases does not change the fact that the BART requirement is an integral part of the statutory scheme in section 169A.

The provisions in section 169B of the CAA, adopted in 1990, do not override EPA's statutory authority to require State plans to remedy regional haze. These provisions grew out of Congress' frustration that EPA had not more expeditiously addressed regional haze under its section 169A delegated rulemaking authority. Thus, section 169B(e) explicitly requires EPA to carry out its ''regulatory responsibilities under section [169A]'' within a set time period. The legislative history confirms that Congress did not intend section 169B to impinge upon EPA's long-standing authority to address regional haze visibility impairment,[96] including the authority to require BART.

The EPA believes that commenters asserting that EPA overemphasized the control of stationary sources and, in particular, the role of BART in the regional haze program misinterpreted the proposal. The EPA did not intend to emphasize controls on BART-eligible sources over, or to the exclusion of, other sources. While the BART requirement is limited to a specified population of major stationary sources, States will need to consider measures addressing a wide range of sources and activities, including mobile sources, area sources, activities involving fire, and other major and non-major stationary point sources in their long-term strategies. The unit on long-term strategies includes further discussion of this point.

Final Rule. The final rule requires each implementation plan to be revised to contain two basic elements related to BART. The first is the requirement that the States submit a list of the ''BART-eligible sources'' in the State. Second, the State must determine and include in the plan the ''best available retrofit technology,'' taking into account certain factors identified in section 169A(g)(2) of the CAA, for each BART-eligible source in the State reasonably anticipated to cause or contribute to any impairment of visibility.

In recognition of the control and cost efficiencies that can be achieved through trading programs and other alternative measures, EPA is providing States with the opportunity to adopt alternative measures in lieu of BART where such measures would achieve even greater reasonable progress toward the national visibility goal. The overarching requirement of the visibility protection provisions of section 169A is to make reasonable progress toward the national goal of eliminating visibility impairment. If greater reasonable progress can be made through an approach that does not require source specific application of BART, EPA believes that approach would comport with this statutory goal. The EPA reached this conclusion in determining the appropriate measures to address visibility impairment in the Grand Canyon National Park resulting from the Navajo Generating Station.[97] In that case, EPA ultimately chose not to adopt the emission control limits indicated by its BART analysis.[98] Instead, as explained by the Ninth Circuit in upholding EPA's final decision, EPA acted within its discretion in adopting an alternative emission control standard ''that would produce greater visibility improvement at a lower cost. Congress's use of the term 'including' in [section 169A(b)(2)] prior to its listing BART as a method of attaining 'reasonable progress' supports EPA's position that it has the discretion to allow States to adopt implementation plan provisions other than those provided by source-specific BART analyses in situations where the agency reasonably concludes that more 'reasonable progress' will thereby be attained.'' [99] Under today's final rule, States may elect to adopt an emissions trading program or other alternative measures in lieu of BART so long as greater reasonable progress is made.

List of BART-eligible sources. To ensure adequate time for developing long-term strategies to ensure reasonable progress, we recommend that States begin identifying and evaluating the list of potential BART sources as soon as possible after promulgation of the final rule. Identifying the BART-eligible sources will require States to collect information as to the dates that emission units at stationary sources were placed into operation, the pollutants emitted, and the potential to emit of these units. We suggest that, at the same time that they begin refining their emissions inventories for $PM_{2.5}$ and its precursors, States request that stationary sources provide them with these dates. While such information is generally available for electric utilities through data bases maintained by the Energy Information Administration, this information is not normally maintained in national data bases for the other 25 source categories subject to BART. However, EPA believes that much of this information is likely to be available in States permitting data bases or other inventories. To assist the States in this task, we will continue efforts to identify other helpful sources of information.

Determination of sources subject to BART. After the State has identified the BART-eligible sources, the next step is determining whether these sources emit any air pollutant ''which may reasonably be anticipated to cause or contribute'' to any visibility impairment in a Federal Class I area. As noted in the proposal, EPA believes that this determination should not require extremely costly or lengthy studies of the contribution of specific sources to regional haze. Unlike the 1980 regulatory program, which addresses the

[93] *See* CAA section 169A(g)(6); see *also Maine* v. *Thomas,* 874 F.2d.883, 885 (1st Cir. 1989) (''EPA's mandate to control the vexing problem of regional haze emanates directly'' from CAA section 169A).

[94] H.R. Rep. No. 294, 95th Cong., 1st Sess. 204 (1977).

[95] 45 FR 80084 (Dec. 2, 1980).

[96] *See* 136 Cong. Rec. S2878 (daily ed. March 21, 1990) (statement of Sen. Adams) (''[t]he authority to establish visibility transport regions and commissions is a supplement to the administrators [sic] obligation under current law. * * * The Administrator may not delay requirements under section 169A because of the appointment of a commission for a region under section 169B'') (daily ed. Oct. 26, 1990) (statement of Rep. Wyden) (''[n]either the original House language nor the Senate language adopted in conference repealed or lessened EPA's obligations under the 1977 law'').

[97] See *Central Arizona Water Conservation District* v. *EPA,* 990 F.2d 1531, 1543 (1993).

[98] See 56 FR at 50178.

[99] Central Arizona Water Conservation District v. *EPA,* 990 F.2d 1531, 1543 (1993).

visibility impairment that is reasonably attributable to a specific source or small group of sources, today's final rule addresses the problem of visibility impairment resulting from emissions from a multitude of sources located across a wide geographic area. As the regional haze rule is not limited to addressing visibility impairment that can be attributed to a specific source or small group of sources, EPA believes it would be inappropriate to focus on the contribution of one source or a small group of sources. First, the States will not face the same need to define the precise contribution from one particular source to the visibility problem. Second, establishing the contribution from one particular source to the problem of regional haze would require lengthy and expensive studies and pose substantial technical difficulties. The EPA has thus concluded that a detailed source-receptor analysis would not be appropriate in determining whether a source ''may reasonably be anticipated to contribute'' to regional haze in a Class I area.

In implementing today's final rule, a State should find that a BART-eligible source is ''reasonably anticipated to cause or contribute'' to regional haze if it can be shown that the source emits pollutants within a geographic area from which pollutants can be emitted and transported downwind to a Class I area. The EPA believes that this test is an appropriate one for determining whether a source can reasonably be anticipated to cause or contribute to the problem of regional haze. As the Ninth Circuit stated in considering this language:

> Congress mandated an extremely low triggering threshold, requiring the installment of stringent emission controls when an individual source ''emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility'' in a Class I Federal area. 42 U.S.C. sec. 7491(b)(2)(A). The NAS correctly noted that Congress has not required ironclad scientific certainty in establishing the precise relationship between a source's emission and resulting visibility impairment.* * * [100]

The approach taken here is consistent with that taken in the programs for acid rain and ozone, programs which also address regional air quality problems caused by transported pollutants. These programs do not require a specific demonstration of each source's contribution to the overall problem, but instead focus efforts on developing cost-effective solutions to reducing emissions over a broad area that is regional or national in scope. For example, in the recent NO_X SIP call addressing the regional transport of NO_X emissions (an ozone precursor) in the Eastern United States, EPA adopted a ''collective contribution'' approach to determining whether sources ''contribute'' to ozone nonattainment in downwind areas. In this rulemaking, EPA concluded that because ozone nonattainment results from the collective contribution of many entities over a broad geographic area, even relatively small (in an absolute sense) contributions from upwind entities should be considered to be ''significant.'' [101]

The EPA has concluded that a similar approach in the regional haze program is appropriate. Where emissions from a region are considered to contribute to regional haze in a Class I area, any emissions from BART-eligible sources in that region should also be considered to cause or contribute to the regional haze problem. The EPA will issue and update guidance, including EPA modeling guidelines,[102] to assist the States in analyzing whether sources contribute to regional haze.

Establishing source-specific BART emission limits. The second element of the BART requirement is for the States to establish emission limitations for those BART-eligible sources which may reasonably be anticipated to cause or contribute to regional haze. To meet this requirement, the State must develop source-specific emission limits which reflect the application of the best system of continuous emission reduction for each pollutant which is emitted by a source subject to BART.[103] As stated above, the State can also choose to develop an emissions trading program, or other alternative measure, that achieve greater reasonable progress rather than require source specific BART emission limits on each source subject to BART.

In developing source specific emission limits for BART, the State must take into consideration the technology available and a number of specific factors set forth in the statute. These factors are the costs of compliance, the energy and nonair environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated from the use of such technology. Taking these factors into account, the State may conclude that BART is the best level of emissions reduction that can be achieved by available retrofit technology or some other level of control. In some cases, the State may determine that a source has already installed sufficiently stringent emission controls for compliance with other programs (e.g., the acid rain program), such that no additional controls would be needed for compliance with the BART requirement. In establishing BART for a particular facility, the State must make available during public review of the SIP at the State level the materials supporting its BART determination. The State must also include this documentation in the technical support materials accompanying the SIP.

In establishing source specific BART emission limits, the State should identify the maximum level of emission reduction that has been achieved in other recent retrofits at existing sources in the source category. As noted above, the visibility 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.'' Recent retrofits at existing sources provide a good indication of the current ''best system'' for controlling emissions. Thus, for example, recent retrofits for large utility sources (e.g., sources under the acid rain program and the Navajo Generating Station) have commonly achieved a 90 percent or better rate of SO_2 emissions (at an average cost of \$265 per ton of SO_2 removed).[105] For source categories with recently promulgated NSPS, that standard may also provide a good indication of the current ''best system'' for controlling emissions. In addition, current information concerning control technology performance for many source categories is available from EPA's Clean Air Technology Center, http://www.epa.gov/ttn/catc. EPA plans to issue revised BART guidance to provide updated guidance to the States on how to calculate BART for purposes of regional haze within a year of promulgation of this rule. The EPA will be developing this guidance through a national stakeholder process.

Once the State has identified the retrofit technology that provides the maximum degree of continuous

[100] *Central Arizona Water Conservaiton District* v. *EPA*, 990 F.2d 1531, 1541 (9th Cir. 1993).

[101] 63 FR 57356, 57376 (Oct. 27, 1998).

[102] See 40 CFR part 51, appendix W for information on EPA's modeling guideline for conducting regional-scale modeling for particulate matter and visibility.

[103] See section 51.301(c).

[104] See CAA section 169A(g)(2).

[105] Ellerman A. Danny et al., Emissions Trading Under the U.S. Acid Rain Program: Evaluation of Compliance Costs and Allowance Market Performance, Massachusetts Institute of Technology, Center for Energy and Environmental Policy Research, 1997.

emission reduction, it should take into consideration the costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control equipment in use at the source, and the remaining useful life of the source. Taking these factors into account allows the State to arrive at an estimate of the ''best system'' of retrofit control technology for a particular source and a corresponding estimate of the likely emissions which would be achieved by the imposition of BART. These factors should be taken into account for each source subject to BART in order to compare tradeoffs between the control efficiencies and costs associated with various control alternatives.

The remaining factor which the States must take into account in determining BART is ''the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.'' In applying this factor in the context of the regional haze program, a State should use the degree of improvement in visibility that would be expected at each Class I area as a result of imposing BART, as determined through the application of the factors discussed above, on all sources subject to BART. For the same reasons that the determination of whether a BART-eligible source may be reasonably anticipated to cause or contribute to a visibility problem should be made on a cumulative basis, EPA believes that a regional analysis is appropriate for determining the degree of visibility improvement that can be achieved through application of BART. Moreover, the statute requires the States to consider ''the degree of improvement in visibility which may reasonably be anticipated to result *from the use of such technology*.'' [106] EPA interprets the language ''from the use of such technology'' to refer to the application of BART level controls to all sources subject to BART. As a result, EPA believes that it is reasonable to interpret this provision as requiring the State to consider, as part of its source-specific analysis, the cumulative impact of applying retrofit controls to all sources subject to BART to estimate the degree of visibility improvement which may reasonably be anticipated to result from the use of BART.

The EPA also believes that such a regional analysis provides important information to the State and to the public about the magnitude of potential emissions from sources subject to BART. This information could be used to help inform the public debate in developing reasonable progress goals, in setting a regional emissions target for a trading program, and in developing the overall long-term strategies for making reasonable progress.

To calculate the degree of improvement in visibility that would be expected at each Class I area as a result of imposing BART on all sources subject to BART, the State should estimate the possible emissions reductions resulting from the application of BART at all subject sources located within the region that contributes to visibility impairment in the Class I area. The State should work on its own or in conjunction with other States, such as in a regional planning body, to determine the geographic scope of the region that contributes to each Class I area. The States should consult with one another to determine the emission reductions achievable from sources subject to BART in other States.

The estimate of possible emission reductions from sources subject to BART should be based on the application of the technology, cost, time for compliance, energy and nonair environmental impacts, and remaining useful life factors discussed above. Using this estimate, the State will then need to calculate the resulting degree of visibility improvement that would be achieved at Class I areas. The EPA expects that this exercise will be in the form of a regional modeling analysis. The State should use this estimated degree of visibility improvement in determining the appropriate BART emission limitations for specific sources.

Unless a State commits to regional planning, a State must include its source-specific BART determinations in its initial SIP revision for the area in which the source is located.[107] Where the State commits to regional planning, a State may defer submitting its source-specific BART determinations consistent with the timing requirements described in unit III.B. However, the State must submit its list of BART-eligible sources at the same time it submits its committal SIP.

The SIP revision must include the emission limitations determined to be BART for sources subject to BART and a compliance schedule for each source. Each source subject to the BART requirement will have to meet the BART emission limitation within 5 years of SIP approval, as required under the CAA. As noted above, within a year, EPA will be issuing revised BART guidance to provide States with assistance in determining BART for regional haze.

Alternative Measures in Lieu of BART. In today's final rule, States may elect to adopt alternative measures, such as a regional emissions trading program, in lieu of BART so long as the alternative measures achieve more reasonable progress than would application of source-specific BART. The EPA believes that a regional emissions trading program would be the most efficient means of achieving BART-level emission reductions and the emission reductions needed to meet the States' reasonable progress goals as implemented through the States' long-term strategies.

The EPA believes that this approach is consistent with the Ninth Circuit's decision in *Central Arizona Water Conservation District* v. *EPA*.[108] In this case, the court upheld EPA's exercise of discretion to adopt an alternative emission standard that achieved greater reasonable progress than would have been achieved through the imposition of BART. Allowing States to adopt alternative measures such as an emissions trading program rather than to require BART will provide the States with the flexibility to achieve greater reasonable progress towards the national goal at a lower cost, while still addressing the Congressional concern that existing sources contributing to visibility impairment be required to control emissions appropriately. The EPA believes that this best fulfills the overarching statutory requirement in section 169A(b) that States make reasonable progress toward the national visibility goal, but also ensures that, at a minimum, the degree of visibility impairment attributable to BART sources is addressed by the States during the first long-term strategy. Moreover, while an appropriately designed alternative might result in differing levels of control at particular sources than a source-by-source BART requirement, the environment will benefit through the achievement of greater reasonable progress.

As noted above, to take advantage of the flexibility offered by this provision, the State must demonstrate that the alternative measures adopted in lieu of meeting the BART requirements achieve greater reasonable progress than would result from the installation of source-specific BART. One way of making this showing is for a State to show in its SIP demonstration that the alternative

CAA section 169A(g)(2) (emphasis added).

[107] For areas designated attainment or unclassifiable for $PM_{2.5}$, this SIP will be due 12 months after the areas are designated. For areas designated as nonattainment, this SIP will be due no later than 3 years after the area is designated nonattainment.

[108] 990 F.2d 1531, 1543 (1993).

measures will achieve greater emission reductions and visibility improvement than would result from meeting the BART requirements.

In making this showing, States may rely on the assessments and analyses developed by regional planning groups that are formed to address regional haze. To compare the emissions reductions and visibility improvement that would result from application of source specific BART to that resulting from implementation of alternative measures, such as a regional emissions trading program, the State must estimate the emissions reductions that would result from the use of BART-level controls. To do this, the State could undertake a source-specific review of the sources in the State subject to BART, or it could use a modified approach that simplifies the analysis.

To simplify the process of arriving at an estimate of emissions, EPA believes that one approach that would be acceptable in place of a source by source BART analysis would be to consider some of the BART factors on a category-wide basis. For example, the average cost per ton of complying with alternate control technologies and associated energy and nonair environmental impacts could be considered on a category-wide basis. It may be more appropriate to consider other factors on a source-by-source basis. For example, the State could identify the current control technology in operation at each source and calculate the emissions that would be achieved at each source with a given retrofit control technology or determine and consider the remaining useful life of individual sources.

Alternatively, EPA believes it may be appropriate for the State to combine a category-wide BART assessment with a source-specific assessment for certain sources. For example, if a State can verify that a source will be retired within a short period of time, it could take this into account in determining BART-level emissions reductions for that facility while assessing the remaining sources subject to BART on a category-wide basis.

The States accordingly have flexibility in developing a method to determine the emission reductions that could be achieved through the application of BART. Whatever methodology is chosen by the State to evaluate possible emissions reductions from BART, the estimate must reflect at least the minimum level of emissions reductions that can be expected. This estimate becomes the point of comparison for determining whether an alternative measure, such as an emission trading program, achieves greater reasonable progress toward visibility improvement. Once the State has arrived at an estimate of the emissions that would result from application of source-specific BART, it should then compare the degree of visibility improvement expected to be achieved in Class I areas through the application of BART to the degree of visibility improvement projected to be achieved by the alternative measures proposed by the State.[109] It is not necessary to go through an additional analysis of the BART factors in considering the effects of alternative measures.

The EPA believes that the most likely alternative measures adopted by the States will be an emissions trading program. There are several advantages associated with a regional trading approach in lieu of meeting a source-specific BART requirement. First, it provides flexibility to participating sources in deciding whether to purchase credits or to implement on-site emission reduction strategies, while being designed to achieve an equivalent level of emissions. Many commenters felt the proposal did not provide this type of flexibility. Second, trading allows sources to assess the costs of control technology, alternative fuels, and process changes across a broad array of sources and source categories. Thus, a trading program typically will result in lower cost per ton of pollutant reduced than a program which mandates plant-specific technological control. For example, EPA's experiences in the acid rain program have shown that sulfur dioxide reductions achieved through market-based programs within the electric utility sector continue to be quite cost effective, in the $170—320 per ton range.[110] A program which allows broader trading among sources in other industrial categories as well would likely lead to even greater cost effectiveness for individual sources.

In designing emissions trading programs that will achieve the requisite improvement in visibility, States must ensure that such programs meet several criteria. First, as noted above, the legislative history demonstrates Congress' recognition of the need to control emissions from a specific set of existing sources. Because of the Congressional focus on control of these sources, any emissions trading program must include, at a minimum, the sources within the trading region subject to BART. The one exception to this is where a source has already installed BART-level pollution control technology and the emission limit is a federally-enforceable requirement. In that case, States may elect to allow a source the option of not participating in the trading program.

Second, a trading program adopted in lieu of BART must be fully implemented within the period of the first long-term strategy. To ensure this, States must provide schedules for implementing emissions trading programs with their SIP submittal. While EPA is allowing States to fully implement a trading program within the period addressed by the State's first long-term strategy, under section 169A, BART emission limits are to be implemented within 5 years. To provide States with the additional flexibility they may need to implement a trading program, EPA has concluded that it is appropriate for States to have the full period of the long-term strategy to achieve the full measure of necessary emissions. The basis for allowing this longer implementation period is the provision that the trading program achieve greater reasonable progress than would be achieved by source-specific application of BART within 5 years of plan submittal. The EPA will consider the estimated period of time to implement the program in determining whether the alternative measures ''achieve more reasonable progress.'' In any event, a trading program adopted in lieu of BART must be implemented during the period of the first long-term strategy.

Third, the reductions in emissions required of BART sources must be surplus to other Federal requirements as of the baseline date of the SIP, that is, the date of the emissions inventories on which the SIP relies. In addition, sources must be required to monitor their emissions in a way that allows States and EPA to assure that the reductions are being achieved. The basic concept of an emission trading program is to allow for alternative, cost-effective ways of achieving equal or greater overall emissions. To ensure that the trading program does achieve a greater overall emission reduction, it is important that the emission credits are created by genuine reductions in emissions. We will be issuing further guidance to assist States in designing

[109] The State should be able to compare the degree of visibility improvement through modeling. For example, for an emissions trading program, the State may undertake a regional modeling analysis that simulates least-cost market trades to predict the geographic distribution of the emission reductions that could be achieved through a market trading program and the resultant improvement in visibility at different Class I areas.

[110] U.S. Department of Energy, Energy Information Administration, ''The Effects of Title IV of the Clean AIr Act Amendments of 1990 on Electric Utilities: An Update,'' DOE/EIA–0582(97), March 1997.

their trading programs to ensure that programs provide such accountability.

Fourth, the regional trading program may include sources not subject to BART. Inclusion of such sources provides for a more economically efficient and robust trading program. The EPA believes the program can include diverse sources, including mobile and area sources, so long as the reductions from these sources can be accurately calculated and tracked.

Fifth, EPA encourages States wishing to develop such programs to consider the emission reduction requirements of other air quality programs. To implement reductions in a fully integrated fashion, the State should consider the extent to which some sources should be limited in their ability to trade. Examples of such factors include the significant contribution to a local nonattainment situation and the extent to which trading may assist or undermine the achievement of greater progress toward attainment of the NAAQS or the national visibility goal.

A related issue is the connection between determinations of BART under the reasonably attributable regulations and a trading program adopted in lieu of BART. The EPA has adopted a provision in the final rule that allows States to include a geographic enhancement in such a trading program to accommodate reasonably attributable BART. The purpose for including this provision is to address concerns regarding ''hot spots''—the concern that some part of visibility impairment in a specific Class I area is attributable or uniquely attributable to a single source or small group of sources because of the nature and location of the pollution from the source(s). Should action be taken by a State (or EPA) to address reasonably attributable impairment, these provisions would allow the State to incorporate methods, procedures, or processes in a market-based strategy to accommodate such action.

Sixth, interpollutant trading should not be allowed until the technical difficulties associated with ensuring equivalence in the overall environmental effect are resolved. Some other emissions trading programs (e.g., trading under the acid rain program) prohibit emission trades between pollutants. An emissions trading program for regional haze might also need to restrict trades to common pollutants. Each of the five pollutants which cause or contribute to visibility impairment has a different impact on light extinction for a given particle mass, making it therefore extremely difficult to judge the equivalence of interpollutant trades in a manner that would be technically credible, yet convenient to implement in the timeframe needed for transactions to be efficient. This analysis is further complicated by the fact that the visibility impact that each pollutant can have varies with humidity, so that control of different pollutants can have markedly different effects on visibility in different geographic areas and at different times of the year. Despite the technical difficulties associated with interpollutant trading today, EPA would be willing to consider such trading programs in the future that demonstrate an acceptable technical approach.

Application for Exemption from BART. Even where a source may reasonably be anticipated to cause or contribute to visibility impairment, section 169A(c) allows for the exemption of any source from the BART requirements if it can be demonstrated that the source, by itself or in combination with other sources, is not reasonably anticipated to cause or contribute to significant visibility impairment. In addition, as specified in section 169A(c)(2) of the CAA, any fossil-fuel fired power plant with a total generating capacity of 750 megawatts or more may receive an exemption only if the owner demonstrates that the power plant is located at such distance from all Class I areas that it does not, or will not, in combination with other sources, emit any pollutant which may be reasonably anticipated to contribute to significant visibility impairment.

As with the question of whether a source can be reasonably anticipated to cause or contribute to any visibility impairment, EPA believes that the question of whether a source causes or contributes to significant visibility impairment requires an analysis of the cumulative effects of emission sources on a region. Regional modeling will be one appropriate method to determine whether a source could qualify for the exemption from the BART requirements. If a significant cumulative impact is demonstrated from the sources across the relevant regional modeling domain, then any BART-eligible source in the region would most likely be found to be reasonably anticipated to cause or contribute to significant visibility impairment.

The proposed regional haze rule was structured such that the BART exemption provisions in section 51.303 of the existing visibility regulations would also apply to sources subject to BART under the regional haze regulation. In the final rule, EPA has taken the same approach. Consistent with section 51.303, a source may apply to EPA for an exemption from the BART requirement. The EPA will grant or deny an application after providing notice and opportunity for a public hearing. Any exemption granted by EPA must have the concurrence from all affected Federal land managers.

Timing for Submittal of BART Elements. Because TEA–21 changed the schedule for submittal of visibility SIPs, EPA is not requiring States to submit a list of BART-eligible sources to EPA within 12 months, as proposed. Under the final rule, the emission limits or other measures to address BART under the regional haze program must be included in the State's initial SIP submittal(s), as discussed further in unit III.B of this notice, except where the State commits to regional planning. In the case where a State opts to work with other States to develop a coordinated approach to regional haze by participating in a regional planning process, SIP revisions containing the BART emission limits or alternative measures in lieu of BART will be due generally at the time $PM_{2.5}$ nonattainment SIPs are submitted, but in no case later than December 31, 2008. As discussed in unit III.B, States that submit a commitment to participate in regional planning are required to submit the list of BART-eligible sources as part of that submittal.

I. Monitoring Strategy and Other Implementation Plan Requirements

Monitoring Strategy

Proposed rule. In the proposed rule, we included a requirement for States to develop a monitoring strategy. We believe that actual monitoring data are a critical component of any air quality management approach to visibility impairment. Data on individual components of PM (nitrates, sulfates, elemental carbon, organic carbon, crustal material) are crucial to understanding the causes of visibility impairment at a given location, and accordingly are necessary for long-term strategy development. Reviewing these data with time, and additional data provided by monitoring sites, are necessary to understand whether the long-term strategies are effective.

Under the proposed rule, an initial monitoring strategy was due 12 months after promulgation, with periodic updates every 3 years thereafter. Requirements for visibility monitoring are authorized under section 110(a)(2)(B), requiring SIPs to provide for the monitoring of ambient air quality, and under section 169A(b)(2), which authorizes EPA to establish regulations requiring SIPs to address ''other measures as may be necessary.''

Four separate provisions were included in the monitoring strategy requirement: (1) a requirement for States to provide for additional that is monitoring ''representative of all Class I areas,'' (2) a requirement for States with Class I areas to assess the relative contributions of sources within and outside the State to any Class I area within the State, (3) requirements for States without Class I areas to include a procedure by which monitoring data will be used to determine the contribution of emissions from within the State to Class I areas outside the State, and (4) a requirement to report all visibility monitoring data to EPA at least annually, in accordance with EPA guidance.

Comments received. Commenters on this requirement raised a number of concerns. One concern raised by State and local agencies was that the costs of monitoring could be substantial and urged EPA to provide funding. Other commenters urged EPA to exercise flexibility in determining the degree to which monitors in one Class I area could be considered representative of other nearby areas. Other commenters raised concerns about the feasibility of monitoring in remote areas and for areas with difficulty in gaining access to monitors during the winter. Commenters also expressed concerns over the timetable for the monitoring plan and the requirement for updating the strategy.

Final rule. Section 51.308(d)(4) of the final rule includes the requirement for a monitoring strategy. Under the final rule, this monitoring strategy is due with the first regional haze SIP, and it must be reviewed every 5 years.

Additional sites. Since the 1980's, EPA has cooperatively managed and funded the IMPROVE network with FLMs and States. Today, the IMPROVE network of 30 Class I sites (and an additional network of about 40 sites that use the IMPROVE methods) collects data on fine particle concentrations and on individual particle species. These individual species (sulfates, nitrates, elemental carbon, organic carbon, crustal material) are important for understanding causes and trends of visibility impairment at a given location. The network also employs optical monitoring methods for the direct measurement of light extinction, and scene monitoring methods using 35 millimeter photography.

The EPA is funding the deployment of several hundred $PM_{2.5}$ monitors by the end of calendar year 1999. In order to meet the requirements for some monitors to characterize background conditions and transport patterns, as well as to more broadly characterize visibility impairment in Class I areas for implementation of the regional haze program, EPA is funding the deployment of an additional 78 IMPROVE sites for Class I areas by the end of 1999. As a result of this anticipated network expansion, we expect that few, if any, State-funded monitors will be needed in implementing today's final rule. The IMPROVE Steering Committee is coordinating closely with the States on the selection of sites for the expanded network to help ensure that the new sites will meet States' needs for SIP development. The EPA expects that as a result of the IMPROVE Steering Committee process, the expanded network should provide for data that can be considered representative of most if not all Class I areas.

The monitoring strategy must, however, provide for additional monitoring sites if the IMPROVE network is not sufficient to determine whether reasonable progress goals will be met. This provision requires States with Class I areas to work with EPA and the FLMs to ensure that monitoring networks provide monitoring data that are representative of visibility conditions in each affected Class I area within the State. We want to clarify that this provision does not require a monitor in each Class I area, only that a monitor be representative of a Class I area. Accordingly, a monitor in or adjacent to one Class I area can be representative of one or more other Class I areas, based on certain criteria. Additionally, EPA agrees with commenters that a few Class I areas may have severe accessibility problems for which monitoring may not be feasible.

Use of Monitoring Data to Understand Contributions to Class I Areas. States with Class I areas are required to include in the regional haze SIP a monitoring strategy that is tailored to a given representative site. The strategy must identify the ways that the visibility monitoring and chemical composition analysis will be used to understand the emission sources that contribute to visibility impairment at a given monitoring site. Additionally, the monitoring strategy should identify the procedures for reviewing monitoring data and coordinating with other technical experts. We believe that continued coordination of visibility monitoring and chemical composition analysis among States, FLMs, and EPA will be important for future regional planning activities. Analysis of trends in emissions of those constituents can assist States in the development of long-term strategies for making reasonable progress.

The rule also requires monitoring strategies for States without Class I areas. We believe it is equally important for those States to understand and describe the implications of monitoring data. First, it is important for those States to review monitoring information, including data on the chemical composition of individual species concentrations, to help understand the relative contribution of emissions from their State to Class I areas in other States. Second, it is important for these States to understand and describe how they will use the monitoring data to review progress and trends.

Periodic Updates to Strategy. The rule requires an initial monitoring strategy and periodic updates. The initial monitoring strategy is due with a State's first SIP submission. Additionally, the rule requires that the monitoring strategy be reviewed every 5 years. We believe that when progress is reviewed and control strategies are updated, it will be important to review the monitoring strategy. For the periodic updates, States should review the existing monitoring strategy with the FLMs and other participating agencies to assess the need for additional monitoring sites or modifications to existing sites, as well as the need for updated guidance on monitoring protocols.

Monitoring Guidance. The EPA plans to issue a visibility monitoring guidance document soon after promulgating this rule that will be designed to assist the States in developing monitoring strategies. The document will include technical criteria and procedures for conducting aerosol, optical, and scene monitoring of visibility conditions in Class I areas. The protocols of the IMPROVE network will be included in this guidance.

Reporting of Monitoring Data

Proposed Rule. The proposed rule required States to report all visibility monitoring at least annually for each Class I area having such monitoring. We proposed that States report data in accordance with EPA guidance and through electronic data transfer techniques to the extent possible. There were no adverse comments on this reporting requirement.

Final Rule. We have retained a general requirement in section 51.308(d)(4) that States submit as part of the SIP a monitoring strategy that addresses the reporting of visibility monitoring data to EPA. As noted above, EPA expects that few, if any, additional State-funded sites will be necessary to fully implement the regional haze rule. Where States do choose to fund additional sites, however, EPA believes it is important for the States to make data from these sites available to EPA and other agencies.

For monitoring sites in the IMPROVE network, the IMPROVE Steering Committee oversees network contractors who quality assure and consolidate data from chemical composition analysis of filter samples. Such data are made available to all interested parties through various electronic formats and online websites. Assuming this practice continues with the IMPROVE Steering Committee, States will experience little or no burden in meeting this requirement for reporting to EPA.

Annual consolidation of these data will serve several purposes. First, a central data base will allow the States and other interested parties to track progress over time in relation to reasonable progress goals. It will also assist the States in understanding current visibility conditions as well as past trends. Consolidation of the data will assist EPA, the State, other agencies, and the public in reviewing the effectiveness of the State's long-term strategy for regional haze. Additionally, consolidation of the data will enable EPA to better characterize national and regional visibility trends in its annual air quality trends report. Finally, a centralized data base will provide for the integration of monitoring data from the new $PM_{2.5}$ monitoring network and the visibility monitoring network, both of which will include $PM_{2.5}$ and PM_{10} mass, as well as compositional analysis by aerosol species. Class I area particle mass and chemical composition data can fill important data gaps in defining regional concentrations for air quality modeling analyses.

Requirements Under Section 110(a)(2) of the CAA. Visibility SIP submittals must document certain program infrastructure capabilities consistent with the requirements of section 169B(e)(2) and section 110(a)(2) of the CAA. Section 169(B)(e)(2) requires States to revise their section 110 SIPs to ''contain such emission limits, schedules of compliance, and other measures as may be necessary'' to carry out regulations promulgated pursuant to this section. The EPA believes that this language authorizes EPA to ensure that States review their existing program infrastructures to ensure that the types of elements required by section 110(a)(2) for programs addressing the NAAQS are also sufficient for adoption and implementation of SIP measures for regional haze. The final rule does not include specific provisions addressing all elements of section 110(a)(2). However, section 51.308(d)(4)(iv) of the final rule requires the State to maintain and update periodically a statewide inventory of emissions of pollutants that contribute to visibility impairment.

Where a State is also revising its SIP to incorporate changes to address the $PM_{2.5}$ NAAQS, many of these revisions may be sufficient to address both $PM_{2.5}$ and regional haze. The EPA encourages States to consider the needs of both programs when updating the provisions required by section 110 of the CAA to minimize any administrative burdens.

J. Periodic SIP Revisions and 5-year Progress Reports

Proposed Rule. The proposed rule required States to periodically review and revise their SIPs every 3 years. The preamble to the proposal stated that ''[t]he EPA believes that a requirement for regular SIP revisions will result in a more effective program over time and provide a focus for demonstrating ongoing progress and making mid-course corrections in emission strategies.'' [111] Each SIP revision would include a comprehensive review of the long-term strategy, and a review of emissions reductions estimates relied on in the previous plan if the State does not achieve any reasonable progress target.

The proposal also requested comment on whether SIP revisions should instead be required every 5 years. Regarding this option, EPA also took comment on whether it should revise the existing requirement in the ''reasonably attributable'' regulations for long-term strategy reviews from every 3 years to every 5 years, such that SIP revision schedules for both regional haze and reasonably attributable impairment would be coordinated.

Public Comments. Some commenters stated that the CAA does not allow EPA to require periodic SIP revisions. Several commenters felt that a requirement to submit comprehensive SIP revisions every 3 years would be overly burdensome, and would not provide enough time to properly evaluate changes in air quality and emissions resulting from implementation of strategies to meet reasonable progress targets. For this reason, a number of commenters supported a 5-year period between SIP revisions. Several participants in the GCVTC supported a 5-year review of progress that meets the procedural requirements of a SIP revision, but that also allows for the State to make a negative declaration if current strategies are deemed adequate for making reasonable progress at that time.

Other commenters supported SIP revisions every 3 years, citing EPA's preamble language, which noted that implementing mid-course corrections after the 5-year mark may in fact be too late to correct situations where impairment is steadily increasing. Some of these commenters also supported the 3-year cycle for regional haze SIPs since it would be consistent with the requirement for 3-year reviews of long-term strategies in the existing 1980 visibility rules.

Authority for Periodic Updates. The EPA does not agree with commenters that it lacks the authority to require periodic SIP revisions. Section 110(a)(2)(F) of the CAA provides that SIPs are to require ''periodic reports on the nature and amounts of emissions and emissions-related data'' and ''correlation of such reports * * * with any emission limitations or standards established pursuant to this chapter.'' Moreover, section 110(a)(2)(H) requires SIPs to provide for revision when found to be substantially inadequate to ''comply with any additional requirements established under * * * [the CAA].'' Both of these provisions provide EPA with the authority to require periodic SIP revisions.

The CAA calls for regulations to protect visual air quality in the Class I areas in a way that assures prevention of future impairment in addition to remedying existing impairment. A one-time review of impairment and development of strategies to address that impairment cannot provide such continuing assurance and, at best, can only focus on remedying currently known manmade visibility impairment within the limits of resources and technology. A program that did not anticipate and provide for the need for future periodic review and revisions, would not be responsive to the national goal of preventing any future manmade visibility impairment.

The requirement for periodic review of SIP measures also directly responds to the CAA goal for States to develop strategies to ensure reasonable progress toward the national goal of no human-caused impairment. Given that the statutory factors which States must consider in determining a reasonable progress goal include costs of control and availability of controls, among others, and given that technology changes can affect costs and availability of controls over time, EPA believes that the requirement for a periodic SIP revision is appropriate. The periodic revisions will assure that the statutory requirement for reasonable progress will

[111] 62 FR 41151.

continue to be met. The EPA believes that the need for periodic updates is also clear from the NAS conclusion that ''achieving the national visibility goal will require a substantial *long-term* (emphasis added) program.'' [112]

Three-year versus 5-year period. In considering the public comments, EPA also took into account the body of evidence indicating a need for multistate regional planning efforts under the regional haze program. Past experience with regional air quality planning efforts, such as the GCVTC or the Ozone Tranport Assessment Group (OTAG), has shown that regional air quality planning efforts often take 2 or more years to complete, with additional time needed for State adoption of measures and for review and approval by EPA.

After consideration of the comments described above, and the timeframes needed for regional planning, EPA concluded that a 5-year progress review and SIP revision cycle is more appropriate than a 3-year cycle. The EPA determined that the States will be better able to assess the effectiveness of emission management strategies by considering 5 years of data rather than 3 years since a 5-year period provides for more stable trend lines for emissions and air quality changes than a 3-year period. The EPA also concluded that a 5-year period should result in significantly less administrative burden on the States than a 3-year period.

Final rule requirements for comprehensive plan revisions and progress reports. The EPA has included in the final rule, two main requirements for comprehensive periodic plan revisions (section 51.308(f)) and progress reviews (section 51.308(g)). Section 51.308(f) requires the States to submit a comprehensive SIP revision in 2018 and every 10 years thereafter. It must meet all of the core requirements of section 51.308(d). The BART provisions of section 51.308(e), as noted above, apply only to the first implementation period. Section 51.308(g) requires progress reports for each Class I area in the State in the form of SIP revisions every 5 years.

Requirements for comprehensive periodic plan revisions. Comprehensive SIP revisions under section 51.308(f) must include all of the implementation plan elements found in section 51.308(d) of the final rule. These elements include, but are not limited to, the following: (1) reasonable progress goals for the next 10-year implementation period, (2) determination of current conditions and review of estimates for natural conditions, (3) a revised long-term strategy, as necessary to achieve the reasonable progress goal for the next 10-year implementation period, and (4) revised emission inventories, technical analyses and monitoring strategies. The EPA wishes to clarify the following points with respect to the basic core provisions of section 51.308(d) for the purpose of periodic comprehensive plan updates.

Reasonable progress goals. For purposes of the periodic plan revisions, the State must select a reasonable progress goal based upon the statutory factors discussed above in unit III.F. In determining the goal for the next implementation cycle, the State must include an analysis of the rate of improvement needed to reach natural conditions by the year 2064 as an analytical framework for the plan revision. To conduct this required analysis, the State must follow the same four steps discussed in unit II.F for the initial plan revision, that is (1) identification of the difference between baseline conditions and natural conditions (noting any updates to the estimate of natural conditions based upon technical refinements), (2) identification of the uniform rate of progress over the 60-year period that would be needed to attain natural conditions by the year 2064, (3) identification of the amount of progress that would result if this uniform rate of progress were achieved during the period of the regional haze implementation plan,[113] and (4) identification of reasonable progress goals in light of the statutory factors, taking the 60-year analysis into account. The State must also calculate 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 required in section 51.308(d)(1)(ii).

Reporting of Baseline and natural visibility conditions. In the SIP submission for the comprehensive periodic plan updates, the State must identify (1) the visibility change from baseline conditions, (2) the visibility change since the last SIP revision 10 years ago, and (3) the difference between current and natural conditions.

Visibility Change from Baseline Conditions. Section 51.308(f) calls for States to consider, at the time of any future SIP revision after the initial implementation plan, the amount of visibility improvement achieved from baseline visibility conditions (established over the period 2000-2004) in developing future reasonable progress goals and associated strategies. The final rule requires the State to do this by comparing ''current conditions'' for the 5 years of most recent visibility data with baseline conditions. (See discussion in unit III.E on definition of ''current.'') Any lack of progress in improvement of visibility from baseline conditions will need to be explained in the SIP revision and considered by the State in the establishment and/or revision of new reasonable progress goals and/or emission management strategies. Similarly, greater than expected improvements should be considered by the State in setting new visibility goals and emission management strategies.

If little or no perceptible visibility improvement has occurred in comparison to baseline conditions, or if conditions have actually degraded, then the State will need to explain the reason for this degradation in the SIP, and should seriously consider establishing more ambitious goals and additional enforceable measures to achieve these goals. The EPA will take into account the amount of progress achieved to date from the baseline period in determining whether any future strategy would ensure ''reasonable progress.'' If significant visibility improvement has occurred from baseline conditions, then EPA can also take this into account in reviewing future reasonable progress goals and strategies.

Visibility Change Since Last SIP Revision. Section 51.308(f) also calls for States, in developing reasonable progress goals for the next 10 years, to take into account how visibility conditions have actually changed since establishment of the previous reasonable progress goal. (This provision would apply beginning in the second SIP revision cycle under the regional haze program.) If conditions degraded or failed to meet reasonable progress goals, the State would be required to analyze the cause of the shortfall, and address it as appropriate in future strategies. If the State has failed to achieve its reasonable progress goal for the prior implementation period, the State would be required to include in its revision a comparison of the visibility improvement the State

[112] National Research Council, NAS Committee on Haze in National Parks and Wilderness Areas, Protecting Visibility in National Parks and Wilderness Areas, National Academy Press, 1993, page 10.

[113] Referring to the example in unit III.F, if the second implementation plan covers a 10-year period from 2019 through 2028, then the State would identify a 3 deciview rate of improvement, and the amount of visibility improvement that must be analyzed for the year 2028 would be the 3 deciview improvement for the years 2019 through 2028, plus the 4.2 deciviews of improvement for the years 2004 through 2018.

expected to achieve to the visibility improvement the State actually achieved.

Difference between current and natural conditions. Section 51.308(f) of the final rule requires the State, at the time of any comprehensive SIP revision, to calculate the difference between current conditions and natural conditions for the most impaired and least impaired days. ''Current conditions'' means the conditions for the most recent 5-year period preceding the required date of the implementation plan submittal. This calculation is needed to determine the total amount of improvement that States will ultimately need to address in their long-term strategies.

Long-term strategies. As for the first implementation plan, subsequent comprehensive updates must identify the enforceable emissions reductions that will provide for meeting the reasonable progress goal for Class I areas within the State and for Class I areas outside the State which may be affected by emissions from the State. Unit III.G provides additional detail on the requirements of the long-term strategies.

Update of monitoring strategies and other requirements. The comprehensive updates are also required to meet the requirements of section 51.308(d)(4) for updated monitoring strategies, updated emission inventories, and other required technical analyses.

Requirements for 5-year progress reports. Section 51.308(g) describes the required elements for progress reports due every 5 years. For States that participate in regional planning and submit initial SIPs in 2008, the first progress report will be due in 2013. If a State submits its initial SIP in the 2004–2008 timeframe, its first progress report would be due before 2013. These progress reports must follow the same procedural requirements required for implementation plan revisions, and the State must provide the opportunity for public review and comment. However, the rule also allows the State to submit this progress report in the form of a negative declaration if the State finds that emission management measures in the SIP are being implemented on schedule, and visibility improvement appears to be consistent with existing reasonable progress goals. The EPA intends for progress reports to involve significantly less effort than a comprehensive SIP revision.

Each 5-year progress report must contain the following elements as specified in section 51.308(g):

- The status of implementation, and summary of the emissions reductions achieved, for all emission management measures implemented within the State in order to achieve reasonable progress goals for Class I areas within and outside the State.
- For each Class I area located in the State, the report must include calculations of the following parameters:
  —Current visibility conditions for the most impaired and least impaired days.
  —The difference between current conditions and baseline conditions for the most impaired and least impaired days.
  —The change in visibility for the most impaired and least impaired days over the past 5 years.
- An emissions tracking report that analyzes the change over the past 5 years in emissions of pollutants contributing to visibility impairment, disaggregated by source category and emissions activity, for significant categories of sources or activities.
- An assessment of whether current implementation plan strategies are sufficient for the State or affected States to meet their reasonable progress goals.

Based on the required calculations and assessments in the progress report, the State must take one of four actions as specified in section 51.308(h). If the State finds that an additional substantive SIP revision is not required, then it may submit a ''negative declaration'' to EPA after opportunity for public review and comment. The EPA anticipates that if the State is implementing a reasonable set of strategies according to the schedule as developed in the previous comprehensive SIP revision, and that visibility trends show that reasonable progress goals should be achieved over the 10-year long-term strategy period, then the State should be able to certify, through a negative declaration, that no additional control measures are needed at the time of this mid-course review.

If the State finds that over the past 5 years there has been a substantial increase in emissions by intrastate sources, or there has been a deficiency in plan implementation, the final rule requires the State to revise the SIP within 1 year, rather than waiting for the next 10-year comprehensive review. Such a mid-course correction would be designed to achieve the existing reasonable progress goal for the relevant Class I area. The EPA believes that it is appropriate for the State to take prompt action to address intrastate problems since they would not need to participate in further regional planning.

If the State finds that there is a substantial increase in emissions or a deficiency in plan implementation resulting primarily from interstate emissions, section 51.308(h)(2) calls for the State to re-initiate the regional planning process with other States so that the deficiency can be addressed in the next comprehensive SIP revision due in 5 years. If the State finds that international emissions sources are responsible for a substantial increase in emissions affecting visibility conditions in any Class I area or causing a deficiency in plan implementation, the State must submit a technical demonstration to EPA in support of its finding. If EPA agrees with the State's finding, EPA will take appropriate action to address the international emissions through available mechanisms. Appropriate mechanisms for addressing visibility-impairing emissions from international sources are further discussed in unit III.G on the long-term strategy.

If EPA finds that the State has not been implementing certain measures adopted into its SIP, or that the State has submitted a SIP that is not approvable, or that the State has failed to submit any required progress report or SIP revision at all, the State could be subject to sanctions in accordance with sections 179(b) and 110(m) of the CAA. If the State does not resolve the situation expeditiously, EPA may be obligated to take further appropriate action to resolve the situation, including promulgation of a FIP within 2 years in accordance with section 110(c) of the CAA. The EPA believes that in this regionally-oriented program, it will be important for States to implement measures designed to improve visibility for Class I areas outside of their State, as well as to improve visibility within the State. The EPA will exercise its FIP authority as appropriate and necessary to ensure that States fulfill their obligations such that Class I areas make reasonable progress toward the national visibility goal.

K. Coordination With Federal Land Managers

Section 51.308(i) of the final rule requires that States consult with FLMs before adopting and submitting their regional haze SIPs. This requirement is consistent with the proposed regional haze rule and the 1980 regulation for ''reasonably attributable'' visibility impairment. A number of commenters expressed a concern that this provision was not equitable, in that States are required to consult with FLMs, but the rule does not require FLMs to consult with States before they take action, even when actions such as prescribed burning could have a significant impact on a State's visibility program. These commenters recommended that the proposed rule be amended to mandate a two-way communication.

The EPA agrees that it is important and necessary for FLMs to consult with States on visibility-related issues. Land-use activities on Federal lands can have impacts on nearby areas of a State, and there have been significant air quality issues related to these activities. In recent years, FLMs have undertaken activities to improve communications with States. There are a number of examples of these efforts. The IMPROVE steering committee, the group that oversees FLM efforts to monitor visibility in Class I areas, includes representation from State agencies. Recently, State representation on this committee was expanded by adding two more State members. Another example are the memoranda of understanding that FLMs have entered into with States to coordinate prescribed burning activities. The EPA believes that the FLM agencies generally recognize the importance of involving States in the development and implementation of land use policies and other actions that affect States' abilities to make air quality improvements.

The EPA believes that it is unnecessary to impose an administrative requirement on another agency of the sort requested by commenters in a Federal rule, because Federal agencies are already subject to compliance with SIP requirements in the same manner, and to the same extent as any nongovernmental entity through section 118, as discussed below. The EPA will, however, be working with FLMs and States to assist in their communications over air quality issues.

Commenters also expressed concerns that emissions from Federal agencies are beyond their jurisdiction. These commenters felt that if States were not able to regulate such emissions, then other sources within the State would be treated inequitably under the final rule. The EPA does not agree that Federal sources are beyond a State's jurisdiction. As required by section 118 of the CAA, if a State air quality regulation affects a given type of source within its jurisdiction, Federal facilities having that type of source must comply with the State regulations in the same manner, and to the same extent as any nongovernmental entity. Thus, FLMs having emission sources of the type that are covered by State air quality regulations are subject to the same extent as private sector entities.

IV. Treatment of the GCVTC Recommendations

A. Background

The EPA established the GCVTC on November 13, 1991.[114] The purpose of the GCVTC was to assess information about the adverse impacts on visibility in and around 16 Class I areas on the Colorado Plateau region and to provide policy recommendations to EPA to address such impacts. Section 169B of the CAA called for the GCVTC to evaluate visibility research as well as other available information ''pertaining to adverse impacts on visibility from potential or projected growth in emissions from sources located in the region.''

The GCVTC was required to issue a report to EPA recommending what measures, if any, should be taken to protect visibility.[115] The CAA required that, at a minimum, this report was to consider: (1) The establishment of clean air corridors,[116] (2) the need to impose additional new source review requirements in any clean air corridors, and (3) additional restrictions on increases in emissions which may be appropriate to protect visibility in affected Class I areas. The GCVTC was also required to address the promulgation of regulations addressing long-range strategies to address regional haze in the region. In June 1996, the GCVTC issued its recommendations to EPA.

The GCVTC recommendations covered a wide range of control strategy approaches, planning and tracking activities, and technical findings. The primary recommendations of the GCVTC covered nine categories of activities:[117]

- Air pollution prevention and reduction of per capita pollution as a high priority, including non-binding targets on production of electricity from renewable energy sources;
- Tracking the effect of new sources of emissions on clean air corridors;
- Closely monitoring stationary source emissions, establishment of regional targets for sulfur dioxide emissions for the year 2000 and the year 2040 with interim targets to be established in the future, exploration of a similar tracking system for other pollutants, and the development of market-based regulatory programs if emissions targets are not met;
- Emissions reductions in and near Class I areas;
- Capping of mobile source emissions for areas contributing to visibility impairment, and State support for national measures aimed at further reducing tailpipe emissions;
- Further assessment of the contribution of road dust to visibility impairment;
- Future binational collaboration to resolve technical and policy concerns about contributions to visibility impairment on the Colorado Plateau resulting from emissions from pollution sources in Mexico;
- Implementation of smoke management programs to minimize effects of all fire activities on visibility; and
- The need for a future regional coordinating entity to follow through on implementing the recommendations.

Proposed rule. In the July 31, 1997 proposal of the regional haze rule, EPA included an extensive review of the recommendations of the GCVTC.[118] The preamble discussed how several concepts from the GCVTC's recommendations were incorporated into the proposed framework for the national regional haze program. For example, EPA proposed an approach for tracking reasonable progress, based on improving conditions on the worst visibility days and not allowing conditions on the best days to degrade, that was consistent with both the GCVTC's definition of ''reasonable progress'' and with the CAA national visibility goal of remedying any existing impairment and preventing any future impairment. The proposal also called for tracking of continuous emissions to inform State control strategy decisions on a periodic basis.[119]

However, in its proposal, EPA chose not to incorporate the GCVTC's specific emission management strategies as direct requirements for SIPs. The EPA followed this approach because the proposed rule was designed to establish a national framework for development of SIPs to remedy regional haze visibility impairment in all Class I areas nationwide. In addition, it was not clear how the various elements of the GCVTC's report were to be translated into SIP requirements. The EPA noted in the proposal that the ''Commission's recommendations have components that contemplate implementation through a combination of actions by EPA, other Federal agencies, States and Tribes in the region, and voluntary measures on the part of the public and private

[114] See 56 FR 57522, Nov. 12, 1991.

[115] CAA Section 169B(d).

[116] A Clean air corridor is defined as a region that generally brings clear air to a receptor region, such as the Class I areas of the Golden Circle.

[117] See GCVTC Report, pp. i–iii.

[118] 62 FR 41141.

[119] 62 FR 41146.

entities throughout the region.'' [120] The EPA indicated that such a mixture of activities made it difficult for EPA to directly require States to implement all of these measures in their SIPs. Instead, the EPA specifically sought public comment on the manner in which the national regional haze program framework, as proposed, would allow for implementation of the GCVTC's recommendations.[121] The EPA also solicited comment on whether to adopt the GCVTC's stationary source strategies with or without modification.[122]

The EPA also reiterated its position in testimony before the United States Congress, stating that ''we specifically designed the regional haze rule to allow for implementation of the GCVTC's recommendations to address the environmental goal of improving visibility.'' [123]

In public meetings and written comments following the proposal, interested parties expressed concern that the proposed rule did not specifically endorse or incorporate the GCVTC's recommendations. Some commentors asserted that the rule ''ignored'' the recommendations. The EPA also received numerous comments that supported adoption of the GCVTC recommendations as part of the national regional haze rule. In particular, several commentors who believed that EPA's proposed rule did not adequately support the GCVTC's recommendations asserted that EPA's participation in the GCVTC implied that strategies developed to address visibility in Class I areas of the Colorado Plateau would be taken into account within the structure of the rule. Commentors also noted that EPA's proposal of a visibility target and requirements to address BART left a high degree of uncertainty as to whether the GCVTC recommendations could form the basis for SIPs.

On June 29, 1998, after the close of the public comment period on the proposed regulations, the WGA sent to EPA additional comments on the proposed regional haze rules. These comments contained specific new language for addressing the recommendations of the GCVTC. The comments offered provisions to be included in the national regional haze rule to allow certain western States to submit SIPs to assure reasonable progress in addressing regional haze impacts on the Colorado Plateau based upon the technical work and policy recommendations of the GCVTC.[124] The transmittal letter signed by Michael O. Leavitt, Governor of the State of Utah, reemphasized the commitment of Western governors to the GCVTC recommendations, and requested that EPA take public comment on their suggested preamble and rule language as part of the EPA process in reaching decisions on a final regional haze rule. In response to this submittal, on September 3, 1998, EPA published a notice of availability in the **Federal Register**.[125] The notice solicited public comment on the contents of the WGA letter and EPA's translation of the letter's requirements for SIPs into draft regulatory language. The comment period for the notice of availability closed on October 5, 1998 and EPA received approximately 125 comments. In summary, most of the commentors supported the adoption of provisions to directly address the GCVTC recommendations in the national rule, although many requested changes to the draft regulatory language. Some commentors expressed concern over how these provisions would relate to the national rule, in particular to the national provisions for BART. Other commentors addressed the way in which the WGA letter and EPA's draft regulatory language translated the GCVTC's recommendations. In addition, some commentors expressed concern over the timing of the SIP submittals both over the linkage to timing of SIP submittals for ozone and $PM_{2.5}$ SIPs and the requirements of TEA–21. Commentors also requested EPA to commit to consider the national transportation measures noted by the GCVTC as part of EPA's responsibility toward helping the States make reasonable progress.

In the final rule, EPA is establishing specific SIP requirements which may be used by the States and tribes that participated in the GCVTC to satisfy the national regional haze rule. These SIP requirements will form a basis for these States to meet the CAA requirements for reasonable progress in the 16 Class I areas addressed by the GCVTC Report. These SIP requirements acknowledge and give effect to the substantial body of work already completed by the States and tribes participating in the GCVTC. The Agency, therefore, and for reasons explained in more detail below, provides these SIP requirements as an optional way for these States and tribes to implement the national rule based on the merits of the work of the GCVTC completed before establishment of the national framework. The EPA finds that the GCVTC actions to date address, or provide a mechanism to address, the statutory factors for assessing reasonable progress required by the CAA. The EPA is satisfied that the GCVTC's strategies as set forth in section 51.309, when supplemented by the annex process discussed below, will provide for ''reasonable progress'' toward the national visibility goal for the 16 parks and wilderness areas addressed by the GCVTC. Consequently, if a State submits a plan that addresses the requirements of section 51.309, including the requirements related to the annex, as described below, that plan will be considered to comply with the national rule's requirement for reasonable progress for the period from plan approval to 2018.

Today's final rulemaking, including section 51.309, is directly responsive to the western States' and tribes' comments calling for recognition of the policy development efforts of the GCVTC. At the same time, the rule allows for future cooperative efforts among the GCVTC States, so that the national requirements for ensuring reasonable progress are fully addressed. This action exemplifies how the regional haze protection provisions can be flexible and allow for a broad range of emissions control strategies tailored to a specific region. This action fully recognizes the GCVTC and its follow-up body, the WRAP, as a valid regional planning process to address, at a minimum, the 16 Class I areas that were the focus of the GCVTC. Section 51.309 provides for continued work of the GCVTC, which may be accomplished through the WRAP, to establish a complete framework which can be adopted in the SIPs for addressing all sources of visibility impairment in the 16 Class I areas. The section also sets forth provisions for addressing additional Class I areas that were not directly addressed in the GCVTC report.

Section 51.309 does not preclude States from developing and adopting their own control strategies. Rather, it provides an expedited process whereby a State choosing to follow the GCVTC's recommendations in its SIP can rely fully on the technical analyses, policy recommendations, and agreements reached by the GCVTC members, thereby significantly reducing the effort required to establish federally approvable SIPs. A State remains free to develop and submit a SIP to EPA which does not rely on the GCVTC's work or

[120] 62 FR 41142.

[121] 62 FR 41143.

[122] 62 FR 41143.

[123] Written Testimony of John S. Seitz, Director, Office of AIr Quality Planning and Standards, U.S. Environmental Protection Agency, before the Subcommittee on Forest and Public Land Management of the Committee on Energy and Natural Resources, United States Senate, October 28, 1997.

[124] Docket A–95–38, Item # VIII–G–76.

[125] 63 FR 46952.

section 51.309. Such a State will be fully subject to the requirements and schedules set forth in section 51.308, in the same manner and to the same extent as the States and tribes throughout the United States that did not participate in the GCVTC process.

B. General Requirements of Section 51.309

Section 51.309 requires specific emissions control strategies for a broad region of the Western United States and includes measures which address different types of emissions sources, including stationary, area and mobile sources. Some of these strategies are already in place while others, such as mobile source provisions and the structure of a market trading system to assure compliance with stationary source emissions goals, will require development of additional regulatory measures. A review of each element of section 51.309 is found in unit IV.C below.

The GCVTC recommended emission reduction targets from stationary sources of SO_2 for the years 2000 and 2040. The GCVTC did not recommend quantitative interim targets between the years 2000 and 2040. Therefore, in addition to provisions for specific emissions strategies, section 51.309 allows for an annex to the GCVTC report which will be considered in establishing specific targets for SO_2 emissions from stationary sources in the region between 2003 and 2018. This annex process and EPA's approval of acceptable interim emissions targets for SO_2 will be key in completing a series of strategies that can be deemed by EPA as meeting reasonable progress for the Class I areas on the Colorado Plateau.

The provisions for adoption of strategies consistent with the GCVTC recommendations do not preclude the States and tribes from developing additional control strategies for achieving reasonable progress in other Class I areas. Nor do they preclude States and tribes which did not participate in the GCVTC, but which may benefit from its strategies due to the geographic proximity of their Class I areas to the State where strategies will be implemented and regional transport throughout the west, from building on these strategies to address reasonable progress for their Class I areas. However, for all Class I areas not on the Colorado Plateau, the States and tribes would need to demonstrate, through the required analyses, that implementation of these strategies would contribute to meeting the requirements of section 51.308. By focusing first on implementation strategies for the 16 Class I areas based on the recommendations of the GCVTC, all western States may reduce the technical and administrative costs of addressing the remaining Class I areas by building on the outcome of existing programs rather than requiring the development of two programs in parallel.

In the national rule, EPA is requiring States to analyze the rate of progress in visibility improvement that would be needed to reach natural conditions within 60 years. The analyses must assess what strategies are available to meet that rate for the period of the long-term strategy. The GCVTC reviewed the period from 1990 to 2040 to assess what strategies were reasonable to achieve visibility improvement in the 16 Class I areas. The GCVTC's Alternatives Assessment Committee developed a modeling system linking emissions control strategies, the costs of such strategies and the degree of visibility improvement that would result from those strategies. While not specifically attempting to reach natural conditions within 60 years, a key emissions control scenario assessed in the GCVTC process was a ''maximum management alternative.'' The GCVTC looked at many source types and their impacts on visibility. This specific assessment applied all known and anticipated control strategies over the time period as an indicator of the maximum amount of improvement in visibility possible in the region. The results of this analysis did not show sufficient emissions to reach natural conditions in any mandatory Class I area by 2040. The analysis of this scenario did, however, demonstrate that the ''maximum management alternative'' is not likely to be achievable based on technological, economic and policy choices made by the Alternates Assessment Committee due to costs, degree of visibility improvement and other factors. Consequently, EPA finds this analysis, plus the management alternatives chosen (i.e., market-based emissions reductions, specific source-sector reductions, etc.) to be an acceptable basis for approvable SIP strategies for the 16 Class I areas for the first long-term strategy period since, in effect, reaching natural conditions by 2040 was shown not to be reasonable in this transport region at this time. In making this finding, EPA concludes that the GCVTC analyses and process provide for an assessment comparable to that called for by section 51.308.

In promulgating section 51.309, EPA is establishing specific SIP requirements for the time period 2003 through 2018 based on demonstrations by the GCVTC. The EPA finds the GCVTC demonstrations satisfy requirements for review of the statutory factors as provided for under subsection 51.308(d).

While the GCVTC's assessment included projections to the 2040, EPA feels that the strategies incorporated in section 51.309 must be re-evaluated in 2018 to assure that they will continue to achieve reasonable progress after a thorough review of the CAA factors. As discussed elsewhere in today's notice, this periodic review and revision of regional haze SIPs is needed because of technological changes and economic factors which are likely to significantly alter both the rate of emissions growth within a region, and the degree to which new technologies can more effectively reduce emissions, both of which can affect the rate of visibility improvement. In addition, the requirement for periodic revisions is consistent with the statutory provisions governing long-term strategies.

The EPA agrees with commentors who noted certain benefits to following the pathway provided through section 51.309 for addressing regional haze impairment. First, there is the benefit that the mixture of required strategies for the 16 Class 1 areas has already been through public comment as part of the GCVTC deliberations and subject to review by many stakeholders. This previous public debate should help ensure broader public support for the State's plans as they are adopted and implemented. As pointed out by commentors, one of the benefits of the GCVTC recommended strategies is that they are aimed at developing cost-effective control strategies and ensuring compliance flexibility for affected sources. For example, the strategy to address emissions from stationary sources uses a milestone and backstop emissions trading program mechanism. This rewards voluntary emissions reductions since a regional emissions trading program would only become effective if regional milestones are exceeded. Given that the provisions for the milestone and backstop emissions trading system may be approvable in lieu of BART, depending on the milestones developed in the annex, full compliance with BART emissions limitations would not be required within 5 years of plan submittal, as would be required of States which submit plans under section 51.308 requiring source-specific BART. In addition, the economies of scale offered by the work of the WRAP in conducting coordinated assessment activities, such as economic and air quality modeling, could be substantial in aiding States in meeting their planning obligations.

Finally, EPA's provisional view that SIPs which meet section 51.309 would satisfy the requirement for reasonable progress minimizes the analyses required of States which adhere to the requirements of section 51.309, compared to States making an independent submittal under section 51.308.

C. Elements of the GCVTC-Based State and Tribal Implementation Plans

1. Time Period

Section 51.309(d)(1) establishes the time period of the plan to cover the 16 parks and wilderness areas for the period 2003 through 2018. The GCVTC's recommended emissions reduction strategies, including the emission reduction approach for stationary sources of SO_2, establish the long-term strategy requirements for plan submittals to EPA until the year 2018. This time period is consistent with the submittals required under section 51.308 which will be due between 2004 and 2008 depending on the classification of State areas with respect to attainment of the recently promulgated NAAQS for $PM_{2.5}$. The time period covered by the plan revision due under section 51.309, 2003–2018, is somewhat different from the timeframe for long-term strategies required by section 51.308 for the Class I areas not on the Colorado Plateau. The differences that exist acknowledge the substantial early work of the GCVTC, on the 16 Class I areas, while at the same time making the strategy review cycle consistent with the timetable established in section 51.308.

The EPA received comment that it should allow the GCVTC recommendations to be the basis of all future strategies to address regional haze for the 16 Class I areas on the Colorado Plateau permanently. The EPA disagrees. No given set of emissions strategies can be determined reliably to achieve reasonable progress into the distant future. While the GCVTC strategies adopted by the States under the provisions of section 51.309 may well continue to be adequate to meet the future long-term strategy requirement, a full review of emissions strategies for all Class I areas of the region is appropriate to assure that ''reasonable progress'' is being achieved and will continue to be achieved during the periods of subsequent long-term strategies. As noted above, the relevant facts concerning costs of controls, availability of control strategies, and other statutory factors will change over time. Advancements in technology and changes in economic factors will likely provide opportunities for implementation of new cost-effective control measures to assure reasonable progress. The structure of EPA's rule is designed to require States, through the SIP process, to review the statutory factors on a periodic basis and determine appropriate changes to their strategies based on that review.

2. Projection of Visibility Improvement

Section 51.309(d)(2) requires the plan to contain a projection of the visibility conditions expected through the year 2018 and to take into account the measures required in the GCVTC report and the provisions of section 51.309. This projection must, at a minimum, be expressed in units of deciview.

The Agency received comment that the GCVTC States should not be required to estimate visibility conditions using the deciview metric, but should be permitted simply to track emissions over time. While EPA encourages States to track emissions in order to evaluate the emission reduction effectiveness of adopted control measures, it is equally important that changes be translated into visibility improvements in order to be responsive to the national goal. As noted earlier in unit III.C of this notice on the deciview metric, EPA's selection of the deciview scale is an appropriate way to do this. The Agency also included this provision to ensure that the public understands the relationship of the SIP to visibility conditions at the Class I areas and to the national goal of no manmade impairment in visibility in these areas. The Agency thus feels that it is appropriate to inform the public on the relationship between chosen emissions control measures and their effect on visibility by requiring States to report on actual and expected changes in visibility to be achieved through implementation of section 31.309. Those changes can be based on monitored data as well as estimated for future conditions based on implementation of emissions strategies. Moreover, the requirement for use of the deciview metric does not prevent the States from using other indicators, in addition to the deciview, for describing regional haze conditions, such as standard visual range or atmospheric light extinction.

3. Treatment of Clean Air Corridors

Section 51.309(d)(3) requires the States to identify a geographic region or regions which will be subject to a comprehensive emissions tracking strategy. The purpose of such comprehensive emissions tracking is to ensure that the frequency of clear days, or days with good visibility, increases or does not decrease at any of the 16 Class I areas addressed by the GCVTC. This section of the rule is designed to make the review of emissions, and their resulting impact on the clear days at the Class I areas, part of the public record through the SIP approval process. It does not mandate any emissions control strategies specifically aimed at improving clear days, but provides for the State to periodically review the need for such strategies. If anthropogenic emissions create visibility impairment above natural conditions, and if overall annual human-caused emissions reductions take place in a region, it is likely that visibility will improve for both the most impaired days and the least impaired days.

The geographic area (or areas) to be covered by the emissions tracking strategy is to be determined initially based on the GCVTC Meteorology Subcommittee's report entitled Clean Air Corridors: A Framework for Identifying Regions that Influence Clean Air on the Colorado Plateau. The geographic area (or areas) can be further refined based on new technical findings over time. The requirement to track emissions will enable States to quickly determine if changes in patterns of emissions will reduce the number of clean air days (defined as the average of the 20 percent clearest days) in any of the 16 Class I areas. The State must analyze the effects of the emissions changes and implement additional measures to protect the clean days if necessary. The States may include the tracking of emissions for the clean air corridors with tracking of emissions for other purposes such as compliance with stationary source emissions targets, if appropriate. The EPA notes that clean air corridors will be protected by other implementation plan requirements, such as other SIP measures that may apply to existing stationary sources. States may wish to rely on technical cooperation now beginning under the WRAP as an efficient means to consolidate efforts on emission inventories and projections needed to monitor clean air corridor emissions and their effects on clear air days.

4. Implementation of Stationary Source Reductions

To achieve the reductions in emissions for stationary sources projected in the GCVTC's strategies, subsection 51.309(f)(1)(i) requires the establishment of SO_2 emission reduction milestones as part of the development of an annex to the GCVTC report. Section 51.309(d)(4) requires monitoring and reporting of stationary source emissions of SO_2 in order to assess compliance with these milestones during the period 2003 to 2018. The SIP must contain criteria and procedures for implementing a market trading program or other program documented in the SIP, consistent with section 51.309(f)(1)(i), if triggered by emissions exceeding the emissions reduction milestones. In particular, the SIPs must provide for implementation of the market-based program or other emissions control strategy as called for by an assessment of SO_2 emissions for the years 2003, 2008, 2013, and 2018. States must fully activate the market system or other program within 1 year after an assessment showing the excessive emissions. In addition, the implementation plan must provide for all affected sources to comply with the market system or other programs allocating emissions within 5 years after the date the program is triggered. The rule also requires States to report on actual emissions reductions and compare them to the established milestones. If a market trading program or other program is triggered, the rule requires States to report whether all sources covered by the market trading or other programs are in compliance with applicable requirements.

In addition to requirements for control of emissions of SO_2, the rule requires the State to explore emission management options for stationary source emissions of PM and NO_X. The States are required to report by 2003 on their consideration of the need for emissions targets for these pollutants to prevent growth in emissions of these pollutants in the region as a whole. The EPA believes that the States should base their decisions on the need for, and levels of, emissions targets for these pollutants on the degree to which such pollutants contribute to regional haze impairment in the Class I areas addressed by their SIPs. The States must report to EPA by 2003 on their decisions whether to develop targets and additional control strategies for PM and NO_X emissions from stationary sources. If the States determine that such targets and controls are needed, they must submit a plan revision to EPA not later than December 31, 2008 containing any necessary long-term strategies and BART or other requirements for stationary sources of PM and NO_X.

In adopting the requirements for stationary source emission reduction milestones in this manner, EPA is indicating that the State's adoption of approvable SO_2 milestones and a backstop market trading program as set forth in section 51.309(f) in addition to the other requirements in section 51.309 would provide for reasonable progress for the 16 Class I areas for the implementation period from 2003 to 2018. The emissions reductions provided for by the milestones and trading program must address the BART provisions in section 51.308(e). For the reasons discussed in the portion of this preamble concerning BART requirements, EPA believes that the GCVTC's adoption of a market based alternative to source-by-source BART will permit the GCVTC States to meet the provisions of the national rule which allow the use of alternative measures in lieu of BART. Implementation of the framework established by subsections 51.309 (d)(4) and (f) will thus satisfy the provisions for an alternative measure in lieu of BART for regional haze impairment set forth in section 51.308(e)(2), provided the interim milestones called for in the annex assure greater reasonable progress than would be achieved by application of BART. The EPA will supplement its actions on the stationary source strategy with future rulemaking on the States' submission of interim milestones for SO_2 emissions as part of the annex. In reviewing the interim milestones, EPA will be informed by the annex to the GCVTC report provided for in section 51.309(f) to be discussed later.

5. Mobile Sources

Section 51.309(d)(5) requires implementation plans to address the contribution to regional haze by emissions from mobile sources. This mobile source provision is based on the finding in the GCVTC Report that reducing total mobile source emissions is an essential part of any long-term strategy for management of visibility on the Colorado Plateau.[126] The GCVTC found that some urban areas will already be developing mobile source emissions budgets and programs to meet other CAA requirements. To the extent that mobile source emissions in these or other areas are found to contribute significantly to visibility impairment in the Class I areas of the Colorado Plateau, the GCVTC recommended that an emissions budget be established for any area with a significant contribution to the regional mobile source emissions total. The GCVTC called for the budgets to be established beginning in the approximate year in which emissions from mobile sources are projected to be at their lowest point during the planning period of 2003 to 2018, which is expected to be in 2005. The emissions budget should serve both as a planning objective and a performance indicator for that area.

Accordingly, today's final rule requires all plans to provide for an inventory of current and projected emissions (VOC, NO_X, SO_2, elemental carbon, organic carbon, and direct fine particles) from mobile sources for the 2003 to 2018 period. Because, as noted in the GCVTC Report, the inventory for the year 2005 is expected to represent the expected lowest total emissions from mobile sources in the planning period, that inventory must be included in the SIP. Once State inventories have been compiled and evaluated, the States with urban areas found to contribute significantly to visibility impairment in the 16 Class I areas must establish and document their mobile source emissions budgets for any such area. In addition, the States must establish SIP components which limit VOC, SO_2, NO_X, elemental and organic carbon and direct fine particulate mobile source emissions to their projected lowest levels for the period 2003 to 2018. The State plans must also provide for the implementation of measures to achieve the mobile emissions budget, and for demonstrations of compliance with any such budget. The demonstrations must include a tracking system to evaluate and demonstrate the State is meeting its share of the regional mobile source emissions budget.

The GCVTC report also noted that the Federal government has a role in addressing mobile source emissions. The GCVTC report identified several national mobile source-related emissions reduction strategies under consideration by EPA that are important to visibility conditions in the Class I areas on the Colorado Plateau. The GCVTC agreed to promote these initiatives on a national level. With regard to ongoing development of policies and regulations on emissions from mobile sources, the June 29 letter from the WGA requests that EPA ''make a binding commitment in its final regional haze rule to fully consider the GCVTC's recommendations' on several national mobile source emissions control strategies. Comment on the regional haze rule specifically requested that EPA commit to consider development of a list of very specific national mobile source emissions control strategies.

The EPA agrees with the GCVTC's conclusion that emissions from mobile sources can be significant contributors to regional haze visibility impairment. The EPA is currently working on a number of the strategies the GCVTC requested us to ''fully consider'' and the

[126] GCVTC Report, pp. 38–46.

summary below indicates the status of activities under way.

No.	Measure	Status of EPA efforts to fully consider the measure
1	Adoption of the 49-State LEV standard in 2001 and Tier II vehicle emission standards in year 2004 (if determined to be more effective).	Combined Tier II/gasoline sulfur NPRM is being drafted, with publication expected in early to mid-1999.
2	Support of EPA's current proposal for new on-road, heavy-duty vehicles emission standards that reduce NO_x emissions by at least 50 percent over the 1998 requirements in the CAA, while maintaining current stringent PM emission limits.	Finalized 2004 standards for on-road heavy-duty in 10/97 [62 FR 54693]; reductions in NO_x emissions and secondary PM.
3	Pursue additional PM reductions from on-road vehicles	Potential actions being evaluated.
4	Pursue additional engine emission standards for new off-road vehicles (heavy-duty, construction-type) that provide reasonably achievable reductions.	Finalized standards in 8/98 [63 FR 56967]. Also planning a technology review by December 2001 to evaluate feasibility standards and additional reductions.
5	Explore broader application of and additional reductions in the sulfur content of both gasoline and diesel fuel.	Gasoline sulfur control-rulemaking underway. Considering regulation of diesel fuel sulfur.
6	Promotion of cleaner-burning fuels	In first year of implementing clean-fuel fleets program. The Office of Mobile Sources presented a series of fleet manager workshops during May, June and July of '98. Clean Fuel Fleet Program Implementation Guidance was issued in August '98. We have a team within OMS working on promoting clean fuels efforts.
7	Pursue fuel standards and control strategies for diesel locomotives, marine vessels/pleasure craft, airplanes, and Federal vehicles as described in the GCVTC's Report.	Study of these issues is ongoing, but no specific actions have been scheduled.
8	Support requirements for effective refueling vapor recovery systems that capture evaporative emissions.	On-board re-fueling standards for cars and trucks finalized October 1996. We may consider refueling systems for on-road, heavy-duty gasoline in future.

The EPA will continue to work with States and regional planning entities to help them assess how national mobile source emissions strategies will affect other strategies needed to ensure reasonable progress toward the national visibility goal during the implementation of the regulations promulgated today. The EPA will also grant States full credit for implementation of future national mobile source programs in emissions strategies needed to attain reasonable progress goals.

6. Emissions Related to Fire

Section 51.309(d)(6) requires documentation that all prescribed fire programs within the State consider and address the effects of smoke on visibility when planning and issuing permits for prescribed fires. The GCVTC Report stated that ''fire has played a major role in the development of and maintenance of most ecosystems in the West.'' [127] In addition, the report notes ''emissions from fire (wildfire and prescribed fire) are an important episodic contributor to visibility-impairing aerosols, including organic carbon, and particulate matter ($PM_{2.5}$)''. Agricultural burning emissions and their effects have been identified as a concern by the GCVTC but have not been quantified due to lack of data. The GCVTC concluded that all types of fire (prescribed fire, wildfire, and agricultural burning) must be addressed equitably as part of a visibility protection strategy.[128]

The EPA agrees with the GCVTC's conclusions and is including in this section of the rule a requirement for the States to address all types of fire in fulfilling the requirements of this section and in submitting SIPs for approval by EPA. Section 51.309(d)(6) requires each State to establish an emissions inventory and tracking system (spatial and temporal) for VOC, NO_X, elemental carbon and organic carbon, and direct fine particulate emissions from prescribed fire, wildfire, and agricultural burning. The EPA believes that such information could be developed on a regional basis and could be accomplished through mechanisms such as recording acres experiencing fire and calculating emissions based on vegetation type and soil moisture. Most importantly, the rule requires the establishment of enhanced smoke management programs for fire that consider visibility effects, in addition to health and nuisance objectives, and calls for programs to be based on the criteria of efficiency, economics, law, emissions reduction opportunities, land management objectives, and reduction of visibility impacts. The comprehensive approach envisioned by the rule will allow States to plan a smoke management program that minimizes visibility impacts but also fully recognizes the ecological role of fire.

The smoke management plans must address all sources of fire used for land management purposes. The provisions of this section also provide for establishment of annual emissions goals for fire (excluding wildfire) that will minimize increases in emissions to the maximum extent feasible. These goals are to be established cooperatively by States, tribes, State and Federal land management agencies, and their private sector counterparts, considering factors similar to those identified for enhanced smoke management plans.

7. Dust From Roads

Section 51.309(d)(7) requires States to assess the impact of dust emissions on regional haze visibility in the 16 Class I areas. If such dust emissions are determined to be a significant contributor to visibility impairment, the State must implement emissions management strategies to address their impact. In the technical work of the GCVTC, road dust was not shown to be a major contributor to regional haze impairment based on current monitoring data. However, work on future emissions projections of road dust emissions was directly tied to growth in vehicle miles traveled (VMT). The large increase projected for the west in VMT over the planning period of the GCVTC report resulted in initial

[127] GCVTC Report, p. 47.

[128] See Id.

predictions of a very large contribution of road dust to regional haze.[129] This technical result was addressed in the GCVTC report and the GCVTC discounted the predictions of the future impacts from road dust. However, the GCVTC recommended that its policy conclusion that distant road dust is not likely to play an important role in regional haze should be confirmed through further tracking of road dust emissions. The GCVTC also emphasized that road dust control should be considered in locations ''in and near'' Class I areas.[130] The EPA agrees with this approach and has included the assessment of road dust as a requirement of the SIP. In addition, today's action requires appropriate SIP measures over time based on the contribution of road dust to regional haze.

8. Pollution Prevention

This section addresses the GCVTC's recommendations on pollution prevention and renewable energy. The GCVTC goal recommended that renewable energy comprise 10 percent of the regional power needs by 2005 and 20 percent by 2015. The Administration has recently offered legislation proposing a national mandate of 7.5 percent by 2010. The Commission's goal represents the outcome of its consensus process and is a more aggressive goal than what the Administration has proposed as a national mandate. As with other GCVTC recommendations, the EPA has included this provision in this rule in recognition of the overall body of the GCVTC's work and believes it is consistent with the provisions of the national rule. Section 51.309(d)(8) requires the State to summarize all pollution prevention plans currently in place, inventory the current and expected energy generation capacity through 2002, the total energy generation capacity and production for the State, the State's percentage of total energy generation and capacity that comes from renewable energy sources, and the State's anticipated contribution toward the GCVTC's goal that renewable energy comprise 10 percent of the regional power needs by 2005, and 20 percent by 2015.

The GCVTC found that to prevent further degradation of vistas in the west, it would be necessary to combine cost-effective pollution control strategies with a greater emphasis on pollution prevention, including low or zero emission technologies and energy conservation. It further found that there was a high potential for renewable energy production, especially electrical energy, and that the relative cost of renewable energy production is declining over time. The GCVTC cited forecasts of renewable energy production by the Western Systems Coordinating Council and by the Land and Water Fund of the Rockies in support of its adoption of the goal that 10 percent of regional power needs be served by renewable energy sources by the year 2005 and 20 percent by the year 2015.[131]

In establishing assessment and reporting requirements for the States, EPA is supporting the GCVTC Report's promotion of renewable power production. Such production will likely be based on emerging renewable energy technologies such as wind, solar, biomass, and geothermal. The EPA also supports tracking annual goals for increases in renewable power generation in the transport region.[132] The GCVTC identified strategies which the States could rely on to help achieve this regional renewable energy goal, including, but not limited to, focusing research funding for renewables, financial incentives, and requiring new power generation projects to include a portion of the generation from renewable energy sources. The EPA notes that the WRAP is committed to following through on the GCVTC's recommendations and can assist the States in developing strategies they can rely on to achieve regional renewable energy goals contained in the GCVTC Report.

In response to the GCVTC's recommendations on pollution prevention, section 51.309(d)(8) calls for each SIP to provide for incentives to reward efforts that go beyond compliance and/or achieve early compliance with air pollution related requirements. The plan also must identify specific areas where renewable energy has the potential to supply power where it is not now provided by current service systems and where renewable energy systems are most cost effective. The plan must contain projections of the short-term and long-term emissions reductions, visibility improvements, costs savings, and secondary benefits associated with renewable energy goals, energy efficiency and pollution prevention activities. The plan must also contain a description of the programs being relied on to achieve the State's contribution toward the GCVTC's renewable energy goals.

The State must provide a demonstration of its progress toward achieving the renewable energy goals in 2003, 2008, 2013 and 2018. The demonstration must include documentation describing the potential for renewable energy resources, the percentage of renewable energy associated with new power generation projects implemented or planned, and the renewable energy generation capacity and production in use or planned within the State. Where a State cannot feasibly meet its planned contribution to the regional renewable energy goals, the State must identify the measures implemented to achieve its contribution and explain why meeting the State's contribution was not feasible.

Commentors on EPA's September 3, 1998 notice of availability stated that incorporation of language from the WGA letter on renewable energy restricts State and local energy planning since a SIP is federally enforceable under the CAA. Commentors also expressed the opinion that the requirements for SIPs to address renewable energy goals may overstep EPA's legal authorities which are limited to emissions limitation and pollution performance standards.

The EPA disagrees that the provisions of section 51.309(d)(8) impermissibly restrict State and local energy planning or that these provisions exceed EPA's authority under the CAA. As stated previously, the requirements of section 51.309 are provided to GCVTC States as an alternative to the general provisions of section 51.308 as a means of giving effect to the policy and technical work of the GCVTC. The goals themselves are not enforceable and States are not required to meet the renewable energy goals. However, as the WGA letter and the GCVTC provide, these provisions are not severable. States which wish to take advantage of the GCVTC's efforts and EPA's acceptance thereof are obligated to meet all of the requirements of section 51.309.

Rather, EPA is setting enforceable requirements for the States to assess progress toward goals established by the GCVTC with respect to renewable energy production as a means for reducing dependence on more polluting forms of energy production. States participating in the GCVTC strategy are responsible for explaining why they cannot meet the GCVTC goals. The required reporting by the States will inform the public of air quality improvements that would result from that goal had it been realized. It is the relationship between renewable energy production and associated environmental effects (direct and

[129] GCVTC Report, p. 46.

[130] See id.

[131] GCVTC Report, p. 28.

[132] GCVTC Report, p. 7.

indirect) that is the thrust of the assessment and reporting effort under the SIP.

9. Implementation of Additional Requirements

In section 51.309(d)(9), EPA requires SIPs to provide for implementation of other GCVTC Report policy and strategy options that can be practicably included as enforceable emissions limits, schedules of compliance or other enforceable measures to make reasonable progress toward the national visibility goal for the 16 Class I areas.

The GCVTC's recommendations included items that are not appropriate to directly translate to SIP requirements for every State. The EPA supports State choice of appropriate actions on other options and measures identified by the GCVTC and has, therefore, established a general provision for SIPs calling for them to consider and adopt additional measures as necessary and appropriate. The rule further requires States to report to EPA in 2003, 2008, 2013, and 2018 on what measures have been adopted and the status of implementation of those measures.

10. International Transport of Pollution

One of the additional areas of concern noted in the GCVTC report, for instance, relates to effects of emissions from sources outside of the territory of the United States. As stated elsewhere in this notice, the EPA will not hold States responsible for developing strategies to ''compensate'' for the effects of emissions from foreign sources. However, the States should not consider the presence of emissions from foreign sources as a reason not to strive to ensure reasonable progress in reducing any visibility impairment caused by sources located within their jurisdiction. The States retain a duty to work with EPA in helping the Federal government use appropriate means to address international pollution transport concerns. Indeed, such efforts are under way. The EPA and other Federal officials are working with representatives of the Mexican government to complete a study which will assess the contribution of fossil-fuel fired electric generation stations in northern Mexico to haze in Big Bend National Park. These efforts and funding of work to establish emissions inventories in Mexico will help address concerns raised by the GCVTC. In addition to activities directly related to visibility effects, there are other efforts underway related to the United States-Mexico border health issues. Given that emissions contributing to health effects and those contributing to visibility impairment are generally the same, the border studies and emissions inventories will help support assessment of regional visibility conditions. In addition to work with Mexico, EPA routinely meets with representatives of the Canadian government on issues related to transport of air pollutants, particularly focusing on emissions affecting acidic deposition. The EPA intends to continue to work through appropriate channels in building technical information and addressing policy concerns related to international pollution transport.

11. Periodic Implementation Plan Revisions

Section 51.309(d)(10) requires the States to periodically assess their progress in implementing measures for protection of visibility. This includes a review of how the measures implemented under section 51.309 are consistent with the national rule's provisions for long-term strategies and BART. The assessments must be completed by 2008, 2013, and 2018 and must be submitted to EPA as SIP revisions that comply with the procedural requirements of sections 51.102 and 51.103. As with any other review and revision of SIP requirements, States will be expected to use the most current available technical methods and procedures in conducting their assessments.

The provisions of section 51.309(d)(10) further require that where a State concludes that planning adjustments are necessary as a result of emissions occurring within the State, it revise its implementation strategies to include rule revisions that are effective within 1 year after the State makes such a conclusion in order to assure reasonable progress at any of the 16 Class I areas on the Colorado Plateau. States may also conclude, based on their assessments, that no changes to the plan are needed, and the plan revision requirement can be met by submitting a ''negative declaration'' as an implementation plan revision to EPA. This revision must provide the State's basis for finding that no changes are needed. This submission will provide the public with necessary information and an opportunity to comment on the State's findings.

The EPA views the requirement of section 51.309(d)(10) as a periodic check on progress rather than a thorough revision of regional strategies. The State interim assessments should focus on significant failures or shortfalls in implementing adopted strategies and on emissions from in-State or out-of-State sources which may be causing degradation in regional haze visibility but were not anticipated in the development of the original plan and will, therefore, not be addressed by currently-adopted programs. If a State makes such findings with respect to in-State sources, EPA expects the State to revise its SIP, reducing emissions to be consistent with the regional planning effort reflected in the reasonable progress SIPs due in 2003. If transport of emissions from out of State is suspected of impairing reasonable progress, the State should identify this to EPA and should initiate cooperative efforts with upwind States so the emissions can be more fully evaluated and, as needed, addressed in the next mandatory full SIP revision. This requirement is virtually identical to the provisions for periodic review under sections 51.308(g) and (h).

12. State Planning and Interstate Coordination

Section 51.309(d)(11) provides flexibility to a State to address its contribution to visibility impairment through the regional emissions control strategies discussed above. The SIP strategies to protect the 16 Class I areas on the Colorado Plateau can thus be developed through interstate coordination in a regional planning process. Such regional planning can help a State develop documentation of the technical and policy basis for the individual State apportionment of emissions and visibility impairment, the contribution to emissions addressed by the State's plan, coordination in the analysis of interstate transport and control of pollution with other States, and compliance with other criteria for approval of SIPs under CAA sections 110 and 169A and B. Therefore, under today's final rule and EPA policy, States may rely on regional entities' efforts to develop and document technical and policy support for the SIPs required by this rule. For the purposes of implementing the requirements of section 51.309, EPA recognizes the WRAP as a regional planning group for purposes of interstate consultation under section 51.308(c).

As indicated in the introduction to the section of today's notice addressing the WGA and GCVTC recommendations, States retain the right to develop their own programs with or without reliance on the work products of a regional entity. In the case where a State chooses to develop a SIP without reliance on a regional planning process, however, the State will need to show how it accounted for the effect of its emissions on Class I areas which may be located beyond the State's borders, as well as the effect of upwind emissions from other States on the Class I areas within its borders.

The regional haze SIP for a State choosing not to implement the requirements of section 51.309, including the SIP submittal deadlines, would be governed by the national rules provided in section 51.308. Any State choosing not to adopt a SIP in accordance with the GCVTC strategy and optional approach in section 51.309, but wishing to use the WRAP mechanism for regional cooperation in developing its SIP requirements, would need to comply with all of the requirements outlined in the national rule in section 51.308.

13. Tribal Implementation Plans

The WGA called for EPA's final rule to permit tribes within the GCVTC Transport Region to implement visibility programs, or reasonably severable elements, in the same manner as States, regardless of whether such tribes have participated as members of a visibility transport GCVTC. The EPA has not included the WGA's recommended rule provision in today's action because the necessary authority for tribal organizations has already been provided in a previous EPA rulemaking.[133] The EPA does, however, agree with the position expressed in the WGA recommendation. The EPA wishes to clarify that tribes may directly implement the requirements of this section of the regional haze rule in the same manner as States. The Tribal Authority Rule provides for this, as discussed further in unit V of today's notice. The independence of tribes means that a tribal visibility program is not dependent on strategies selected by the State or States in which the tribe is located. If tribes within the Transport Region decline to implement visibility programs and EPA finds that emissions management strategies are needed to assure reasonable progress, EPA will work with the appropriate tribes directly to provide for Federal implementation of appropriate emissions reduction strategies. This is based on the government to government principles of Federal-Tribal relations.

D. Requirements for States Electing Not To Follow All Provisions of the Section 51.309(e)

The EPA notes that the provisions for allowing the Transport Region States to adopt SIPs based on the GCVTC recommendations requires that States endorse the range of strategies recognized by the GCVTC. A State electing not to implement the GCVTC recommendations as set forth in section 51.309(d) must address all of its Class I areas and any Class I area to which its sources' emissions may contribute to impairment under the provisions of section 51.308. In addition, any Transport Region State must advise other States electing to comply with section 51.309 of the nature and effect of their program on visibility impairing emissions so that other States can use this information in developing programs under section 51.309. This provision assures that all components needed to address reasonable progress are part of SIPs either under the provisions of section 51.309 or section 51.308.

E. Annex to the GCVTC Report

1. Interim Milestones

Section 51.309(f) calls for an annex to the GCVTC Report for the purpose of completing the program requirements to meet reasonable progress under the CAA, including submission of a complete long-term strategy and addressing the BART requirement for the 16 Class I areas on the Colorado Plateau. The purpose of the annex is to develop interim emissions milestones for stationary source SO_2 interim targets between the year 2000 target and the target for the year 2040. Under section 51.309(f)(1)(i), the States must consider four specific factors in setting the interim emission milestones. The first factor affecting the selection of interim milestones is the GCVTC's definition of reasonable progress. The GCVTC notes in its report that the term ''reasonable progress'' refers to ''progress in reducing human-caused haze in Class I areas under the national visibility goal.'' [134] It goes on to note that ''the CAA indicates that 'reasonable' should consider the cost of reducing air pollution emissions, the time necessary for compliance, the energy and non-air quality environmental impacts of reducing emissions, and the remaining useful life of any existing air pollution source considered for these reductions.'' The discussion also includes the GCVTC's Public Advisory Committee definition that ''progress towards the national visibility goal is achieving continuous emissions reductions necessary to reduce existing impairment and attain steady improvement in visibility in mandatory Class I areas, and managing emissions growth so as to prevent perceptible degradation of clean air days.'' Together, these provisions call for the achievement of continuous emissions reductions and tracking the reductions to ensure visibility improvement in hazy days and visibility maintenance on clear days. To be consistent with and responsive to the guiding principles, recommendations and strategies adopted by the GCVTC, EPA expects any interim targets to demonstrate a significant continuous downward trend in emissions and not postpone significant progress to periods covered by future long-term strategies.

The second factor is the quantifiable target for 2040 to which interim targets must contribute. This target is a 50 to 70 percent reduction by 2040 in emissions from stationary source SO_2 emissions, based on the projection of the GCVTC's baseline forecast scenario from actual 1990 emission levels. Interim targets should reflect assessment of reasonable measures which reduce regional loadings of SO_2. Such assessments may include examination of interim targets based on costs per ton of reducing SO_2 in line with recently adopted control measures.

The third factor is the applicable requirements of the CAA for making reasonable progress and implementing BART. As noted previously in this preamble, the CAA requires a long-term strategy to ensure reasonable progress and the application of BART to certain large sources that are reasonably anticipated to cause or contribute to regional haze. The rule requires the annex to address the BART provisions of the national rule. As noted in the earlier discussion of BART, EPA will accept alternative measures, such as regional emissions trading programs, which achieve greater reasonable progress in lieu of meeting the source-specific BART requirement. As noted elsewhere in the preamble, EPA plans to issue revised BART guidance within a year. During the next year and a half, EPA also plans to issue new or revised guidance related to the design of emission trading programs, including guidance on the structure of economic incentive programs. Given this schedule, EPA intends to work closely with the WRAP as it develops the annex, its approach to meeting the rule's BART requirements and its backstop market-trading program. The EPA believes that its participation in the WRAP will help to ensure that the way in which the annex addresses BART and the market trading program will be compatible with EPA's revised BART guidance and any new or revised guidance EPA issues related to emissions trading programs.

In the event EPA finds that the annex does not meet the rule's BART provisions because it is inconsistent

[133] *See* 63 FR 7254 (Feb. 12, 1998).

[134] GCVTC Report, p. x–xi.

with EPA's revised BART guidance, the Transport Region States may submit a revised annex to address any deficiencies. The revision should be submitted as expeditiously as practicable but no later than 12 months from EPA's determination that the annex is deficient with respect to BART due to its inconsistency with the BART guidance. Similarly, if EPA finds the annex does not meet the provisions of any EPA guidance applicable to market-trading programs that is issued after promulgation of this rule, the Transport Region States may submit a revision to the annex to remedy any such deficiencies. These revisions should also be submitted no later than 12 months from EPA's determination that the annex cannot be incorporated in the SIP because of inconsistencies with the guidance. The EPA expects that the States and WRAP stakeholders will make every effort to address both the revised BART guidance and any new or revised emission trading program guidance within the timeframe established by section 51.309 for submittal of the annex. By providing for EPA participation in the WRAP, encouraging State and stakeholder efforts to respond expeditiously to new or revised guidance, and calling for any needed revisions to the annex to be submitted within a year from an EPA determination of deficiency, this approach will ensure compliance with the SIP submittal deadlines in section 51.309(c).

The fourth factor to be addressed in the setting of interim milestones is the timing of implementation plan assessments of progress and the identification of mechanisms to address cases where emissions exceed milestone levels for the reporting years 2003, 2008, 2013 and 2018. This schedule is designed to achieve eventual coordination of target years with assessments for regions affecting other Class I areas. Because these efforts call for continuing consultation and sharing of information between regions as well as between States, timetables for further work by the GCVTC States are designed to bring the GCVTC States' long-term strategy updates in line with the schedule for the next long-term strategy update required of all other States.

2. Documentation of Market Trading or Other Alternative Measures To Assure Reasonable Progress.

In addition to the interim targets, section 51.309(f)(1)(iii) requires the annex to contain final documentation of the market trading program or other programs to be implemented by the GCVTC States if current implementation plans and voluntary measures are not sufficient to meet the established interim milestones. This documentation must include model rules, memoranda of understanding, and other materials necessary to describe in detail and establish in enforceable fashion how emission reduction progress will be monitored, what conditions will require the market trading program to be activated, how allocations will be performed, and how the program will operate.

3. Additional Class I Areas

An additional provision, section 51.309(g) allows States to elect to demonstrate reasonable progress for other Class I areas within the Transport Region States beyond the original 16 areas addressed by the GCVTC's assessment, relying on the strategies recommended by the GCVTC. See the discussion in unit IV.F. of this preamble.

4. Geographic Enhancements

The EPA has also adopted provisions in subsections 51.309(b)(7) and 51.309(f)(4) that would allow the Transport Region States to establish a process as part of a broad regional strategy, such as backstop market-trading program, to accommodate the situation where a State takes action to address reasonably attributable BART under the provisions of section 51.306(c)(2). As noted elsewhere, the annex, if approved, will allow the Transport Region States to submit a SIP which adopts an alternative measure in lieu of BART. The purpose for including the provisions regarding geographic enhancement is to address the intersection between the existing reasonably attributable BART provision and regional haze BART, which may be met through an emissions trading program such as the milestone/backstop market-trading program which is to be included in the annex. Existing rules address ''hot spots'—those situations in which part of the visibility impairment in a specific national park or wilderness area is reasonably attributable to a single source or small group of sources in the airshed because of the nature and location of the pollution relative to the Class I area. Should action be taken by the State to address such reasonably attributable impairment through BART, the geographic enhancement provisions would allow the backstop market-based trading program to accommodate such action. These provisions parallel a similar allowance in subsections 51.301(ii) and 51.308(e)(2)(C)(v).

The EPA is repeating these provisions, with minor language changes, to be clear that they apply to both the milestones or backstop market-trading program provided for in the annex. Subsection 51.309(b)(7) defines the term geographic enhancement for the provisions governing the annex and section 51.309(f)(4) allows the annex to contain a geographic enhancement. Similar to the national program, these provisions will allow the market trading system included in the annex to accommodate situations where a State wishes to require BART control measures on sources or a small group of sources due to reasonably attributable impairment and that source has been included in the backstop market trading program under the annex. In this situation, the milestone or backstop market-trading program may include a level of reasonably attributable impairment which may require additional emissions reductions over and above those achieved under the quantitative emissions reductions milestones established for regional haze.

5. The EPA Responsibilities in Relation to the Annex

Section 51.309(f)(3) spells out EPA's responsibilities with respect to the annex and calls for EPA to publish the annex upon receipt. The EPA must then conduct a review and decide, after notice and opportunity for public comment, whether the annex meets the requirement of section 51.309(f)(1) and whether it assures reasonable progress. If EPA finds the interim targets and accompanying documentation meet the requirements of reasonable progress, then it will incorporate the interim targets into the stationary source SIP requirements in section 51.309(d)(4) within 1 year of receipt, after public notice and comment. If EPA decides that the annex does not meet SIP requirements for reasonable progress or if EPA does not receive an annex, it will notify the GCVTC States, who will then be subject to the general provisions of section 51.308 in the same manner as other States.

One commentor on the annex approach described in EPA's September 3 notice of availability noted that the WGA letter set forth a tight timetable for development of the market system and that it appears to violate the TEA–21 requirements. In response, EPA notes that these are the timetables established by the GCVTC in 1996 and which have been the basis for work by the follow-up body of the WRAP. With respect to TEA–21, the colloquy between Senator Allard and Senator Baucus in the Congressional Record on the conference report concerning implementation of GCVTC recommendations is instructive, and EPA believes that it fully addresses the commentor's concern. Senator Baucus stated that ''[TEA–21] clarifies that it does not affect EPA's authority to provide for State implementation of the agreements and recommendations set forth in the June 1996 GCVTC Report on a schedule consistent with the GCVTC's Report. * * * The conferees added specific language so as not to preclude the Administrator from providing for earlier State implementation of the GCVTC's agreements and recommendations * * *.'' [135] That language states that:

> The preceding provisions of this paragraph shall not preclude the implementation of the agreements and recommendations set forth in the GCVTC Report dated June 1996.

TEA–21 section 4102(c)(2).

F. Additional Class I Areas

Section 51.309(g) calls for Transport Region States to identify in their 2003 plan submissions whether they elect to meet the provisions of section 51.308 or 51.309 in establishing their long-term strategy and BART requirements for additional Class I areas not covered by the original GCVTC effort. By no later than December 31, 2008 the States electing to use section 51.309 to address additional Class I areas must submit plan revisions which include a modeling demonstration establishing expected visibility conditions on the most-impaired and least-impaired days at the Class I areas for which they seek to demonstrate reasonable progress. These demonstrations may be conducted by the State or based on refined studies conducted by regional entities. The plan must include the analyses required in section 51.308(d)(1). The plan can build upon and take full credit for the strategies adopted for the 16 Class I areas. It must also contain any additional measures beyond those strategies that may be needed to demonstrate reasonable progress in those areas, in accordance with the provisions of section 51.308(d)(1) through (4). As provided for in section 51.309(g)(2), a Transport Region State may have until no later than December 31, 2008, to submit a plan for additional Class I areas, which is the date for submission that additional Class I areas under section 51.308. Transport Region States may well benefit by addressing the additional Class I areas under section 51.309, since using the same rule provision for both sets of Class I areas could facilitate coordination of the requirements for the areas as well as enabling consolidation of plans after 2008.

Furthermore, if the State can develop the necessary demonstration for other Class I areas before 2003, a Transport Region State could submit one implementation plan in 2003 covering both the 16 Class I areas and other Class I areas for which it must assure reasonable progress.

V. Implementation of the Regional Haze Program in Indian Country

This section discusses how the requirements of the regional haze rule relate to emissions released from Indian country.

A. Background on Tribal Air Quality Programs

Before discussing how the regional haze rule affects tribes, we believe it is useful to briefly describe EPA's overall policy and rulemaking efforts on tribal air quality programs.

On November 8, 1984, the EPA released a policy statement entitled ''EPA Policy for the Administration of Environmental Programs on Indian Reservations.'' This policy statement, available on the Internet at http://www.epa.gov/indian/1984.htm, stresses a number of themes. In particular, this policy stresses that EPA, consistent with overall Federal government policy, will pursue the principle of Indian ''self-government,'' and that it will work with tribal governments on a ''government-to-government'' basis. The policy statement also emphasizes EPA's desire to work with interested tribal governments in developing programs and in preparing to assume regulatory and environmental program management responsibility for Indian country. The EPA will retain responsibility for protecting tribal air quality until such time as tribes administer their own air quality protection programs.

The CAA, as amended in 1990, added a new section 301(d) which authorizes EPA to ''treat tribes as States'' for the purposes of administering CAA programs. Section 301(d) required that EPA promulgate regulations listing specific CAA provisions for which it would be appropriate to treat tribes as States and establishing the criteria that tribes must meet in order to be eligible for such treatment under the CAA. The EPA proposed these regulations on August 25, 1994 (59 FR 43956), and finalized the rule on February 12, 1998 (63 FR 7254). Much of the regulatory language in this rule is codified in the Code of Federal Regulations (CFR) as a new 40 CFR part 49. This rule is generally referred to as the Tribal Authority Rule or TAR.

The TAR includes general eligibility requirements for tribes interested in assuming program responsibilities that are codified in section 49.6 of the rule. These eligibility requirements are designed in part to ensure that such tribes have the infrastructure needed to successfully implement a tribal air quality program. Tribes may request a formal eligibility determination using administrative procedures contained in 49.7. Tribes may also use the administrative procedures in 49.7 to seek approval to implement CAA programs. The TAR authorizes EPA to review requests for eligibility determinations and program approvals simultaneously. As noted in 49.7(c), tribes that are interested in seeking EPA approval to implement air quality programs under the CAA may request approval to implement only partial elements of a CAA program, so long as the elements of the partial program are ''reasonably severable.''

Section 301(d)(4) of the CAA confers discretionary authority on EPA to provide, through regulation, alternative means to ensure air quality protection in cases where it determines that treating tribes as ''identical'' to States would be inappropriate. Accordingly, in promulgating the TAR, EPA provided flexibility to tribes seeking to implement the CAA. Some flexibility is established by virtue of EPA's decision, under 49.4 of the final rule, not to treat tribes as States for specified provisions of the CAA. The rationale for this approach is discussed on pages 7264 and 7265 of the preamble to the final rule, and in unit III.B of the preamble to the proposed rule. For example, unlike States, tribes are not required by the TAR to adopt and implement CAA plans or programs, thus tribes are not subject to mandatory deadlines for submittal of implementation plans. As discussed in the preamble sections identified above, EPA believes that it generally would not be reasonable to impose the same types of deadlines on tribes as on States. Among the CAA provisions for which EPA has determined it will not treat tribes as States is section 110(c)(1) of the CAA, which requires EPA to intervene and ensure air quality protection within 2 years after a State either fails to adopt a SIP or does not win EPA approval for a SIP that was determined to be deficient. The EPA did not apply this provision to tribes because the section 110(c) obligation on EPA to promulgate a FIP is based on failures with respect to required submittals, and, as noted above, tribal submissions under the TAR are voluntary, not mandatory.

[135] 144 Cong Rec. SS407 (daily ed. May 22, 1998).

Instead, pursuant to its section 301(d)(4) discretionary authority, EPA has provided in the TAR that, where necessary and appropriate, it will promulgate FIPs within reasonable timeframes to protect air quality in Indian country. See 40 CFR 49.11(a).

B. Issues Related to the Regional Haze Program in Indian Country

Today's final rule imposes requirements for revisions to SIPs. The rule requires States to develop SIP revisions to address regional haze, to update the SIP every 10 years, and to continue to evaluate progress toward the national visibility goal. The requirements of today's final rule are among those air quality programs for which tribes may be determined eligible and receive authorization to implement under the TAR. Tribes wishing to assume these regional haze program requirements and be ''treated as States'' may seek approval under 40 CFR 49, but are not required to do so. Where tribes do not take on this responsibility, EPA will ensure air quality protection in Indian country consistent with the provisions of 40 CFR 49.11(a).

We encourage tribes to participate in regional planning efforts for regional haze. A good example of tribal participation in regional haze planning is the efforts of tribal representatives on the GCVTC. These efforts are continuing with tribal participation on the WRAP. The EPA expects, as noted above, that additional regional planning groups will be formed in reaction to today's final rule. A number of tribes have indicated interest in participating in regional planning efforts, and we believe this is beneficial in many respects. Tribal participation can help provide emissions inventory information that can serve to better understand the importance of sources in Indian country to regional visibility impairment. Conversely, such participation can also help provide a forum for tribal participants to alert regional planning organizations as to concerns on how regional emissions are affecting air quality in Indian country.

As noted in the preamble to the TAR, we intend to work with tribes to identify air quality priorities and needs, to build communication and outreach to tribes on air quality issues, and to provide training to build tribes' technical capacity for implementing air quality programs. We recognize, however, that not all tribes will have the resources nor the expertise to participate in regional planning efforts for regional haze. An important EPA role in regional planning efforts will be to ensure that the overall objectives of the regional haze program are met where tribes are unable to participate.

In order to encourage tribes to develop self-sufficient programs, the TAR provides tribes with the flexibility of submitting programs as they are developed, rather than in accordance with statutory deadlines. This means that tribes that choose to develop programs, where necessary may take additional time to submit implementation plans for regional haze over and above the deadlines in the TEA–21 legislation as codified in today's final rule. (See unit III.B for a discussion of these deadlines.) The TEA–21 legislation changed the deadlines for State submission of SIP revisions to address regional haze, which were originally set out in section 169B(e)(2) of the CAA. Section 49.4(f) of the TAR provides that deadlines related to SIP submittals under section 169(B)(e)(2) do not apply to tribes. We encourage tribes choosing to develop implementation plans to make every effort to submit by the deadlines to ensure that the plans are integrated with and coordinated with regional planning efforts. In the interim, EPA will work with the States and tribes to ensure that achievement of reasonable progress is not delayed.

As noted previously in unit II of this notice, sections 169A and 169B of the CAA contain requirements for visibility protection in Class I areas, and do not require that States or tribes develop plans and control strategies for visibility protection for additional locations. These provisions of the CAA do not require implementation plans to address regional haze in other Class I areas, such as those designated as Class I by tribes or States under section 164 of the CAA. One commenter from a tribe expressed concerns that the scenic beauty and value of tribal areas should not be viewed by EPA as less important than the national parks and wilderness areas that have ''mandatory Class I'' status. While EPA believes that these tribal areas are not afforded the same legal protection under the CAA as Class I areas, it is important for tribes to understand that the regional haze control program for the Federal areas will help to protect scenic locations of interest to tribes. For example, EPA believes that modeling analyses aimed at addressing Class I areas can readily add receptor locations to analyze the visibility improvements at selected tribal locations. The EPA will work with regional planning bodies to ensure that tribal interests are represented and to foster communication between States and tribes, and we will encourage the consideration of impacts on visibility in tribal locations in regional planning efforts.

VI. Miscellaneous Technical Amendments to the Existing Rule

The rule includes the following changes to coordinate the requirements of today's regional haze rule with the 1980 visibility regulations for ''reasonably attributable'' visibility impairment:

Section 51.300. Purpose and Applicability

We have amended this section to clarify that subpart P includes provisions for regional haze as well as reasonably attributable visibility impairment.

Section 51.301. Definitions

We have added the following terms: reasonably attributable visibility impairment, regional haze, deciview, State, most-impaired days, least-impaired days, implementation plan, tribe, BART-eligible source, and geographic enhancement. The other definitions in this section apply to the program for reasonably attributable impairment as well as the new regional haze program, except where it is noted that they only apply to the program for reasonably attributable impairment.

Section 51.302. Implementation Control Strategies

We have changed references in section 51.302(a) to the administrative process requirements for public hearings and SIP submissions, which are now located in section 51.102 and 51.103. We have also amended this section to clarify that the implementation control strategies addressed in the section apply to reasonably attributable visibility impairment.

Section 51.305. Monitoring

We have amended this section to clarify that the monitoring requirements in this section apply to reasonably attributable visibility impairment.

VII. Administrative Requirements

In preparing any final rule, EPA must meet the administrative requirements contained in a number of statutes and executive orders. In this section of the preamble, we discuss how the final regional haze rule addresses these administrative requirements.

A. Regulatory Planning and Review by the Office of Management and Budget (OMB) (Executive Order 12866)

Under Executive Order 12866 (58 FR 51735, October 4, 1993,) the Agency must determine whether the regulatory action is ''significant'' and, therefore, subject to OMB review and the requirements of the Executive Order. The Order defines ''significant regulatory action'' as one that is likely to result in a rule that may:

(1) have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(2) create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) materially alter the budgetary impacts of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

(4) raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, it has been determined that this rule is a ''significant regulatory action'' and EPA has submitted it to OMB for review. The drafts of rules submitted to OMB, the documents accompanying such drafts, written comments thereon, written responses by EPA, and identification of the changes made in response to OMB suggestions or recommendations are available for public inspection at EPA's Air and Radiation Docket Information Center (Docket No. A–95–38).

The EPA has prepared and entered into the docket a Regulatory Impact Analysis (RIA) entitled Regulatory Impact Analysis for the Regional Haze Rule. This RIA assesses the costs, economic impacts, and benefits for four illustrative progress goals, two sets of control strategies, two sets of assumptions for estimating benefits, and systems of national uniform versus regionally varying progress goals. The RIA is a caveated and illustrative assessment of the potential consequences of the regional haze rule in 2015, a year near the end of the first long-term progress period, 2018. As a result of comments from the public as well as changes initiated by EPA staff, the RIA has a broader scope, improved data, and more realistic modeling than the analysis issued with the proposed rule.

Despite these improvements, the RIA is not a precise reflection of the actual costs, economic impacts, and benefits associated with the progress goals and emission management strategies developed as a result of the final regional haze rule. This is due to the fact that under the regional haze rule, the States bear the primary responsibility for establishing reasonable progress goals as well as emission management strategies for meeting these goals. Until such time as the States make those decisions, EPA can only speculate as to which goals may be established and what types of control requirements or emission limits might result from the associated emission management strategies.

According to the RIA, there is substantial visibility improvement due to emissions from other CAA programs such as those for the new O3 and PM NAAQS and the Tier 2 mobile sources rule. With illustrative goals ranging from 1.0 deciview improvement in 15 years to 10 percent deciview improvement in 10 years, the RIA finds that between 22 and 52 percent of the Class I area counties in the continental U.S. achieve or surpass the progress goals due to emissions reductions from other CAA programs. Furthermore, by looking at only partial attainment of the PM and O3 NAAQS and a modest (relative to the proposed rule) Tier 2 program, the RIA understated the visibility improvements from these and other CAA programs. Hence, if States established reasonable progress goals equivalent to the amount of visibility improvement which could be achieved by other CAA programs, the incremental control costs of the regional haze rule may be less than the costs estimated in the RIA, as noted below, for the first long-term strategy period. Under these conditions there could be costs associated with the planning, analysis, and BART control elements of the rule. Incremental annualized costs for those elements are estimated to be $72 million (1990 dollars).

However, if States all choose to establish the same illustrative progress goal, the RIA estimates incremental control costs ranging from $1 to $4 billion with associated benefits ranging from $1 billion to $19 billion. But, visibility is not the only monetized effects category. Many of the benefits which could be monetized are associated with improvements to human health and other welfare effects. This is because the emission control strategies targeted at improving visibility in Class I areas also generate air quality improvements in many other parts of the country. However, the estimated visibility benefits which are monetized are substantial, ranging, for example, from 86 to 111 percent of control costs for the 1 deciview improvement in 15 years illustrative progress goal and from 32 to 52 percent for the 10 percent deciview improvement in 10 years illustrative progress goal.

The RIA finds that the estimated net benefits (benefits minus costs) may increase and the potential for adverse economic impact would decrease if States exercise their discretion to establish State or region-specific reasonable visibility progress goals and emission-management strategies.

According to the RIA simulations, not all Class I areas achieve or surpass the illustrative visibility progress goals even after the simulation of two sets of control strategies. But, the visibility improvement is substantial with 84 to 94 percent of the 121 counties with 147 Class I areas in the continental U.S. achieving the 1.0 deciview in 15 years goal and 31 to 43 percent of the areas achieving 10 percent deciview improvement in 10 years goal. Furthermore, all areas have improved visibility. How much of the estimated progress shortfall is due to the failure of the RIA to fully account for the visibility progress due to other CAA programs and advances in control technology is unknown.

The RIA, although highly caveated and illustrative, represents an improvement over the analysis prepared for the proposed rule. Furthermore, the RIA demonstrates significant visibility progress in 121 counties with 147 Class I areas in the continental U.S. These improvements result from other CAA programs as well as those targeted at the illustrative progress goals. Despite incomplete coverage of effects and pollutants, the monetized benefits of strategies associated with illustrative nationally uniform goals are substantial, outweighing the control strategy costs under most conditions for the first long-term strategy period. However, higher net benefits may result and the potential for significant adverse impact may be mitigated if States exercise the discretion to establish reasonable progress goals and emission management strategies. The flexibility for State discretion is, of course, exactly what the regional haze rule provides.

B. Regulatory Flexibility Act

The EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with this final rule. The EPA has also determined that this rule will not have a significant impact on a substantial number of small entities because the rule does not establish requirements applicable to small entities.

The Regulatory Flexibility Act (5 U.S.C. §§ 601 et seq.) (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act (Pub. L.

No.104–121) (SBREFA), provides that whenever an agency is required to publish a general notice of proposed rulemaking, it must prepare and make available an initial regulatory flexibility analysis, unless it certifies that the proposed rule, if promulgated, will not have ''a significant economic impact on a substantial number of small entities.'' 5 U.S.C. § 605(b). Courts have interpreted the RFA to require a regulatory flexibility analysis only when small entities will be subject to the requirements of the rule. See *Motor and Equip. Mfrs. Ass'n* v. *Nichols,* 142 F.3d 449 (D.C. Cir. 1998); *United Distribution Cos.* v. *FERC,* 88 F.3d 1105, 1170 (D.C. Cir. 1996); Mid-Tex Elec. Co-op, Inc. v. FERC, 773 F.2d 327, 342 (D.C. Cir. 1985) (agency's certification need only consider the rule's impact on entities subject to the rule).

As stated in the proposal, the regional haze rule will not establish requirements applicable to small entities. The rule applies to States, not to small entities. The rule requires States to develop, adopt, and submit SIP revisions that will ensure reasonable progress toward the national visibility goal, and would generally leave to the States the task of determining how to obtain those reductions, including which entities to regulate. In developing emission control measures, section 169A of the CAA requires States to address BART for a select list of major stationary sources defined by section 169A(g)(7) of the CAA. As noted in the proposal, however, the State's determination of BART for regional haze involves some State discretion in considering a number of factors set forth in section 169A(g)(2), including the costs of compliance. Further, the final rule allows States to adopt alternative measures in lieu of requiring the installation and operation of BART at these major stationary sources. As a result, the potential consequences of today's final rule at specific sources are speculative. Any requirements for emission control measures, including any requirements for BART, will be established by State rulemakings. The States will accordingly exercise substantial intervening discretion in implementing the final rule.

For the final rule, EPA is confirming its initial certification that the rule would not have a significant impact on a substantial number of small entities. The EPA notes, however, that the Agency did conduct a more general analysis of the potential impact on small entities of possible State implementation strategies. This analysis is documented in the RIA. In addition, as noted in the proposal, EPA undertook small-entity outreach activities on a voluntary basis. The EPA also has issued guidance, entitled ''Guidance on Mitigation of Impact to Small Business While Implementing Air Quality Standards and Regulations,'' which can be found on the internet at: http://ttnwww.rtpnc.epa.gov/implement/actions.htmıOther. This guidance outlines potential implementation strategies that would mitigate impacts on small sources and encourages States to make use of these strategies wherever possible and appropriate. The EPA did receive comments regarding the impact on the regional haze rule on small entities. These comments are addressed in the Response to Comments document.

C. Paperwork Reduction Act—Impact on Reporting Requirements

The information collection requirements in this rule relating to State requirements for the protection of visibility in Class I national parks and wilderness areas were submitted to OMB for review and approval under the Paperwork Reduction Act, 44 U.S.C. 3501, *et seq.* An Information Collection Request document was prepared by EPA (ICR No. 1813.02) and a copy may be obtained from Sandy Farmer, by mail at OPPE Regulatory Information Division, U.S. EPA (2137) 401 M Street, S.W.; Washington, DC 20460, by email at *farmer.sandy@epamail.epa.gov,* or by calling (202) 260–2740. A copy may also be downloaded off the internet at *http://www.epa.gov/icr.* The information requirements are not effective until OMB approves them.

This collection of information has an estimated reporting burden, for the fifty States and District of Columbia, of approximately 22,000 to 47,000 hours for a 3-year period between mid-1999 and mid-2002. The Agency expects the Federal burden will be approximately 1900 to 4000 hours for the 3-year period. The Agency anticipates States costs of about $980,000 to $2,064,000 for the 3-year period. The Agency estimates the annual Federal costs to be approximately $83,000 to $175,000 for the 3-year period. These estimates include time for reviewing requirements and instructions, evaluating data sources, gathering and maintaining data, and completing and reviewing the collection of information.

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 OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR Part 9 and 48 CFR Chapter 15.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4) (UMRA), 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 the UMRA, 2 U.S.C. 1532, EPA generally must prepare a written statement, including a cost-benefit analysis, for any proposed or final rule that ''includes any Federal mandate that may result in the expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $100,000,000 or more * * * in any one year.'' A ''Federal mandate'' is defined under section 421(6), 2 U.S.C. 658(6), to include a ''Federal intergovernmental mandate'' and a ''Federal private sector mandate.'' A ''Federal intergovernmental mandate,'' in turn, is defined to include a regulation that ''would impose an enforceable duty upon State, local, or tribal governments,'' section 421(5)(A)(i), 2 U.S.C. 658(5)(A)(i), except for, among other things, a duty that is ''a condition of Federal assistance,'' section 421(5)(A)(i)(I). A ''Federal private sector mandate'' includes a regulation that ''would impose an enforceable duty upon the private sector,'' with certain exceptions, section 421(7)(A), 2 U.S.C. 658(7)(A).

Before promulgating an EPA rule for which a written statement is needed under section 202 of the UMRA, section 205, 2 U.S.C. 1535, of the 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 RIA prepared by EPA and placed in the docket for this rulemaking is consistent with the requirements of section 202 of the UMRA. Furthermore, EPA is not directly establishing any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments. Thus, EPA is not obligated to develop under section 203 of the UMRA a small government agency plan. Further, as described in the proposal, EPA carried out consultations with the governmental entities affected by this rule in a manner consistent with the intergovernmental consultation provisions of section 204 of the UMRA.

The EPA also believes that because the rule provides States with substantial flexibility, the proposed rule meets the UMRA requirement in section 205 to select the least costly and burdensome alternative in light of the statutory mandate to issue regulations that make reasonable progress toward the national visibility protection goal. The rule provides States with the flexibility to establish reasonable progress goals and BART based on certain criteria, one of which is the costs of compliance. The rule also provides States with the flexibility to adopt alternatives, such as an emissions trading program, in lieu of requiring BART. Finally, the rule provides the States with the flexibility to develop long-term strategies. The regional haze rule, therefore, inherently provides for adoption of the least costly, most cost effective, or least burdensome alternative that achieves the objective of the rule.

The EPA is not reaching a final conclusion as to the applicability of the requirements of UMRA to this rulemaking action. It is questionable whether a requirement to submit a SIP revision constitutes a Federal mandate. The obligation for a state to revise its SIP that arises out of sections 110(a), 169A and 169B of the CAA is not legally enforceable by a court of law and, at most, is a condition for continued receipt of highway funds. Therefore, it is possible to view an action requiring such a submittal as not creating any enforceable duty within the meaning of section 421(5)(A)(i) of UMRA (2 U.S.C. 658(5)(A)(i)). Even if it did, the duty could be viewed as falling within the exception for a condition of Federal assistance under section 421(5)(A)(i)(I) of UMRA (2 U.S.C. 658(5)(A)(i)(I)). As noted earlier, however, notwithstanding these issues, the discussion in section 2 and the analysis in Chapter 8 of the RIA constitutes the UMRA statement that would be required by UMRA if its statutory provisions applied, and EPA has consulted with governmental entities as would be required by UMRA. Consequently, it is not necessary for EPA to reach a conclusion as to the applicability of the UMRA requirements.

E. Environmental Justice—Executive Order 12898

Executive Order 12898 requires that each Federal agency make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minorities and low-income populations. The requirements of Executive Order 12898 have been addressed to the extent practicable in the RIA cited above, particularly in chapters 2 and 9 of the RIA.

F. 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 U.S. The EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the U.S. prior to publication of the rule in the **Federal Register**. A ''major rule'' cannot take effect until 60 days after it is published in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. section 804(2). This rule will be effective August 30, 1999.

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

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 E.O. 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency. The EPA interprets E.O. 13045 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under section 5–501 of the Order has the potential to influence the regulation. The regional haze rule is not subject to E.O. 13045 because it does not establish an environmental standard intended to mitigate health or safety risks.

H. Enhancing the Intergovernmental Partnership—Executive Order 12875

Under Executive Order 12875, EPA may not issue a regulation that is not required by statute and that creates a mandate upon a State, local or tribal government, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by those governments, or EPA consults with those governments. If EPA complies by consulting, Executive Order 12875 requires EPA to provide to the OMB a description of the extent of EPA's prior consultation with representatives of affected State, local and tribal governments, the nature of their concerns, copies of any written communications from the governments, and a statement supporting the need to issue the regulation. In addition, Executive Order 12875 requires EPA to develop an effective process permitting elected officials and other representatives of State, local and tribal governments ''to provide meaningful and timely input in the development of regulatory proposals containing significant unfunded mandates.''

Today's final rule does not create a mandate on State, local or tribal governments. As explained in the discussion of UMRA (unit VII.D), this rule does not impose an enforceable duty on these entities. Accordingly, the requirements of section 1(a) of Executive Order 12875 do not apply to this rule.

The EPA notes, however that considerable consultation has taken place with State, local and tribal government representatives in developing the final regional haze rule. In September 1995, EPA formed a subcommittee under the authority of the Federal Advisory Committee Act to advise the Agency on various issues related to implementation of the revised ozone and particulate matter NAAQS and the regional haze program. This group met a total of 13 times between September 1995 and completion of its duties in December 1997. Several State and local governmental representatives were on this subcommittee. The EPA received and reviewed comments from over 40 States and 1 tribal government on the July 1997 proposal. Tribes in the west have been active in discussion on regional haze, both as members of the GCVTC, and in the follow-on body, the WRAP. In addition, EPA has held numerous meetings with State and local representatives.

I. Executive Order 13084: Consultation and Coordination With Indian Tribal Governments

Under Executive Order 13084, EPA may not issue a regulation that is not required by statute, that significantly or uniquely affects the communities of Indian tribal governments, and that imposes substantial direct compliance costs on those communities, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by the tribal governments, or EPA consults with those governments. If EPA complies by consulting, Executive Order 13084 requires EPA to provide to OMB, in a separately identified section of the preamble to the rule, a description of the extent of EPA's prior consultation with representatives of affected tribal governments, a summary of the nature of their concerns, and a statement supporting the need to issue the regulation. In addition, Executive Order 13084 requires EPA to develop an effective process permitting elected officials and other representatives of Indian tribal governments ''to provide meaningful and timely input in the development of regulatory policies on matters that significantly or uniquely affect their communities.''

Because the rule does not establish a visibility progress goal or emission management strategy, the rule does not impose control or other direct compliance requirements. Hence, the rule does not create a mandate on tribal governments. Accordingly, the requirements of 3(b) of Executive Order 13084 do not apply to this rule.

J. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Pub. L. No. 104–113, section 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This action does not involve technical standards. Therefore, EPA did not consider the use of any voluntary consensus standards.

List of Subjects in 40 CFR Part 51

Environmental protection, Administrative practice and procedure, Air pollution control, Carbon monoxide, Nitrogen dioxide, Particulate matter, Sulfur oxides, Volatile organic compounds.

Dated: April 22, 1999.

Carol M. Browner,

Administrator.

For the reasons set forth in the preamble, part 51 of chapter I of title 40 of the Code of Federal Regulations is amended as follows:

PART 51—REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS

1. The authority citation for Part 51 is revised to read as follows:

Authority: 42 U.S.C. 7410, 7414, 7421, 7470–7479, 7491, 7492, 7601, and 7602.

Subpart P—Protection of Visibility

2. Section 51.300 is amended by revising paragraphs (a), (b)(1) introductory text, and (b)(2), and by adding paragraph (b)(3) to read as follows:

§ 51.300 Purpose and applicability.

(a) *Purpose.* The primary purposes of this subpart are to require States to develop programs to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution; and to establish necessary additional procedures for new source permit applicants, States and Federal Land Managers to use in conducting the visibility impact analysis required for new sources under § 51.166. This subpart sets forth requirements addressing visibility impairment in its two principal forms: ''reasonably attributable'' impairment (i.e., impairment attributable to a single source/small group of sources) and regional haze (i.e., widespread haze from a multitude of sources which impairs visibility in every direction over a large area).

(b) *Applicability.* (1) *General Applicability.* The provisions of this subpart pertaining to implementation plan requirements for assuring reasonable progress in preventing any future and remedying any existing visibility impairment are applicable to:

* * * * *

(2) The provisions of this subpart pertaining to implementation plans to address reasonably attributable visibility impairment are applicable to the following States:

Alabama, Alaska, Arizona, Arkansas, California, Colorado, Florida, Georgia, Hawaii, Idaho, Kentucky, Louisiana, Maine, Michigan, Minnesota, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, North Carolina, North Dakota, Oklahoma, Oregon, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Virgin Islands, Washington, West Virginia, Wyoming.

(3) The provisions of this subpart pertaining to implementation plans to address regional haze visibility impairment are applicable to all States as defined in section 302(d) of the Clean Air Act (CAA) except Guam, Puerto Rico, American Samoa, and the Northern Mariana Islands.

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3. Section 51.301 is amended by removing the paragraph designations, placing the defined terms in alphabetical order, revising the definitions of *Federal Land Manager, Major stationary source, Natural conditions,* and *Visibility impairment,* and adding in alphabetical order definitions of *Reasonably attributable visibility impairment, Regional haze, Deciview, State, Most impaired days, Least impaired days, Implementation plan, Indian tribe* or *tribe, BART-eligible source,* and *Geographic enhancement for the purpose of § 51.308* to read as follows:

§ 51.301 Definitions.

* * * * *

BART-eligible source means an *existing stationary facility* as defined in this section.

* * * * *

Deciview means a measurement of visibility impairment. A deciview is a haze index derived from calculated light extinction, such that uniform changes in haziness correspond to uniform incremental changes in perception across the entire range of conditions, from pristine to highly impaired. The deciview haze index is calculated based on the following equation (for the purposes of calculating deciview, the atmospheric light extinction coefficient must be calculated from aerosol measurements):

Deciview haze index=10 $\ln_e (b_{ext}/10\ Mm^{-1})$.

Where b_{ext}=the atmospheric light extinction coefficient, expressed in inverse megameters (Mm^{-1}).

* * * * *

Federal Land Manager means the Secretary of the department with authority over the Federal Class I area (or the Secretary's designee) or, with respect to Roosevelt-Campobello International Park, the Chairman of the Roosevelt-Campobello International Park Commission.

* * * * *

Geographic enhancement for the purpose of § 51.308 means a method, procedure, or process to allow a broad regional strategy, such as an emissions trading program designed to achieve greater reasonable progress than BART for regional haze, to accommodate BART for reasonably attributable impairment.

Implementation plan means, for the purposes of this part, any State Implementation Plan, Federal Implementation Plan, or Tribal Implementation Plan.

* * * * *

Indian tribe or *tribe* means any Indian tribe, band, nation, or other organized group or community, including any Alaska Native village, which is federally recognized as eligible for the special programs and services provided by the United States to Indians because of their status as Indians.

* * * * *

Least impaired days means the average visibility impairment (measured in deciviews) for the twenty percent of monitored days in a calendar year with the lowest amount of visibility impairment.

Major stationary source and major modification mean major stationary source and major modification, respectively, as defined in § 51.166.

* * * * *

Most impaired days means the average visibility impairment (measured in deciviews) for the twenty percent of monitored days in a calendar year with the highest amount of visibility impairment.

Natural conditions includes naturally occurring phenomena that reduce visibility as measured in terms of light extinction, visual range, contrast, or coloration.

* * * * *

Reasonably attributable visibility impairment means visibility impairment that is caused by the emission of air pollutants from one, or a small number of sources.

* * * * *

Regional haze means visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources.

* * * * *

State means ''State'' as defined in section 302(d) of the CAA.

* * * * *

Visibility impairment means any humanly perceptible change in visibility (light extinction, visual range, contrast, coloration) from that which would have existed under natural conditions.

* * * * *

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4. Section 51.302 is amended by revising the section heading, paragraphs (a), (c) introductory text, (c)(1), (c)(2) introductory text, (c)(4) introductory text, and (c)(4)(iv) to read as follows:

§ 51.302 Implementation control strategies for reasonably attributable visibility impairment.

(a) *Plan Revision Procedures.* (1) Each State identified in § 51.300(b)(2) must have submitted, not later than September 2, 1981, an implementation plan meeting the requirements of this subpart pertaining to reasonably attributable visibility impairment.

(2)(i) The State, prior to adoption of any implementation plan to address reasonably attributable visibility impairment required by this subpart, must conduct one or more public hearings on such plan in accordance with § 51.102.

(ii) In addition to the requirements in § 51.102, the State must provide written notification of such hearings to each affected Federal Land Manager, and other affected States, and must state where the public can inspect a summary prepared by the Federal Land Managers of their conclusions and recommendations, if any, on the proposed plan revision.

(3) Submission of plans as required by this subpart must be conducted in accordance with the procedures in § 51.103.

* * * * *

(c) *General plan requirements for reasonably attributable visibility impairment.* (1) The affected Federal Land Manager may certify to the State, at any time, that there exists reasonably attributable impairment of visibility in any mandatory Class I Federal area.

(2) The plan must contain the following to address reasonably attributable impairment:

* * * * *

(4) For any existing reasonably attributable visibility impairment the Federal Land Manager certifies to the State under paragraph (c)(1) of this section, at least 6 months prior to plan submission or revision:

* * * * *

(iv) The plan must require that each existing stationary facility required to install and operate BART do so as expeditiously as practicable but in no case later than five years after plan approval.

* * * * *

5. Section 51.305 is amended by revising the section heading and paragraph (a) to read as follows:

§ 51.305 Monitoring for reasonably attributable visibility impairment.

(a) For the purposes of addressing reasonably attributable visibility impairment, each State containing a mandatory Class I Federal area must include in the plan a strategy for evaluating reasonably attributable visibility impairment in any mandatory Class I Federal area by visual observation or other appropriate monitoring techniques. Such strategy must take into account current and anticipated visibility monitoring research, the availability of appropriate monitoring techniques, and such guidance as is provided by the Agency.

* * * * *

6. Section 51.306 is amended by revising the section heading, paragraph (a)(1), paragraph (c) introductory text, and paragraph (d) to read as follows:

§ 51.306 Long-term strategy requirements for reasonably attributable visibility impairment.

(a)(1) For the purposes of addressing reasonably attributable visibility impairment, each plan must include a long-term (10–15 years) strategy for making reasonable progress toward the national goal specified in § 51.300(a). This strategy must cover any existing impairment the Federal Land Manager certifies to the State at least 6 months prior to plan submission, and any integral vista of which the Federal Land Manager notifies the State at least 6 months prior to plan submission.

* * * * *

(c) The plan must provide for periodic review and revision, as appropriate, of the long-term strategy for addressing reasonably attributable visibility impairment. The plan must provide for such periodic review and revision not less frequently than every 3 years until the date of submission of the State's first plan addressing regional haze visibility impairment in accordance with § 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 long-term strategy for addressing reasonably attributable and regional haze visibility impairment, and the State must submit the first such coordinated long-term strategy. Future coordinated long-term strategies must be submitted consistent with the schedule for periodic progress reports set forth in § 51.308(g). Until the State revises its plan to meet this requirement, the State must continue to comply with existing requirements for plan review and revision, and with all emission management requirements in the plan to address reasonably attributable impairment. This requirement does not affect any preexisting deadlines for State submittal of a long-term strategy review (or element thereof) between August 30, 1999, and the date required for submission of the State's first regional haze plan. In addition, the plan must provide for review of the long-term strategy as it applies to reasonably attributable impairment, and revision as appropriate, within 3 years of State receipt of any certification of reasonably attributable impairment from a Federal Land Manager. The review process must include consultation with the appropriate Federal Land Managers, and the State must provide a report to the public and the Administrator on progress toward the national goal. This report must include an assessment of:

* * * * *

(d) The long-term strategy must provide for review of the impacts from any new major stationary source or major modifications on visibility in any mandatory Class I Federal area. This review of major stationary sources or major modifications must be in accordance with § 51.307, § 51.166, § 51.160, and any other binding guidance provided by the Agency insofar as these provisions pertain to protection of visibility in any mandatory Class I Federal areas.

* * * * *

7. Section 51.307 is amended by revising paragraph (a) introductory text, (a)(2) and (c) to read as follows:

§ 51.307 New source review.

(a) For purposes of new source review of any new major stationary source or major modification that would be constructed in an area that is designated attainment or unclassified under section 107(d)(1)(D) or (E) of the CAA, the State plan must, in any review under § 51.166 with respect to visibility protection and analyses, provide for:

* * * * *

(2) Where the State requires or receives advance notification (e.g. early consultation with the source prior to submission of the application or notification of intent to monitor under § 51.166) of a permit application of a source that may affect visibility the State must notify all affected Federal Land Managers within 30 days of such advance notification, and

* * * * *

(c) Review of any major stationary source or major modification under paragraph (b) of this section, shall be conducted in accordance with paragraph (a) of this section, and § 51.166(o), (p)(1) through (2), and (q). In conducting such reviews the State must ensure that the source's emissions will be consistent with making reasonable progress toward the national visibility goal referred to in § 51.300(a). The State may take into account the costs of compliance, the time necessary for compliance, the energy and nonair quality environmental impacts of compliance, and the useful life of the source.

* * * * *

8. A new § 51.308 is added to subpart P to read as follows:

§ 51.308 Regional haze program requirements.

(a) *What is the purpose of this section?* This section establishes requirements for implementation plans, plan revisions, and periodic progress reviews to address regional haze.

(b) *When are the first implementation plans due under the regional haze program?* Except as provided in paragraph (c) of this section and § 51.309(c), each State identified in § 51.300(b)(3) must submit an implementation plan for regional haze meeting the requirements of paragraphs (d) and (e) of this section by the following dates:

(1) For any area designated as attainment or unclassifiable for the national ambient air quality standard (NAAQS) for fine particulate matter ($PM_{2.5}$), the State must submit a regional haze implementation plan to EPA within 12 months after the date of designation.

(2) For any area designated as nonattainment for the $PM_{2.5}$ NAAQS, the State must submit a regional haze implementation plan to EPA at the same time that the State's plan for implementation of the $PM_{2.5}$ NAAQS must be submitted under section 172 of the CAA, that is, within 3 years after the area is designated as nonattainment, but not later than December 31, 2008.

(c) *Options for regional planning.* If at the time the SIP for regional haze would otherwise be due, a State is working with other States to develop a coordinated approach to regional haze by participating in a regional planning process, the State may choose to defer addressing the core requirements for regional haze in paragraph (d) of this section and the requirements for BART in paragraph (e) of this section. If a State opts to do this, it must meet the following requirements:

(1) The State must submit an implementation plan by the earliest date by which an implementation plan would be due for any area of the State under paragraph (b) of this section. This implementation plan must contain the following:

(i) A demonstration of ongoing participation in a regional planning process to address regional haze, and an agreement by the State to continue participating with one or more other States in such a process for the development of this and future implementation plan revisions;

(ii) A showing, based on available inventory, monitoring, or modeling information, that emissions from within the State contribute to visibility impairment in a mandatory Class I Federal Area outside the State, or that emissions from another State contribute to visibility impairment in any mandatory Class I Federal area within the State.

(iii) A description of the regional planning process, including a list of the States which have agreed to work together to address regional haze in a region (i.e., the regional planning group), the goals, objectives, management, and decisionmaking structure of the regional planning group, deadlines for completing significant technical analyses and developing emission management strategies, and a schedule for State review and adoption of regulations implementing the recommendations of the regional group;

(iv) A commitment by the State to submit an implementation plan revision addressing the requirements in paragraphs (d) and (e) of this section by the date specified in paragraph (c)(2) of this section. In addition, the State must commit to develop its plan revision in coordination with the other States participating in the regional planning process, and to fully address the recommendations of the regional planning group.

(v) A list of all BART-eligible sources within the State.

(2) The State must submit an implementation plan revision addressing the requirements in paragraphs (d) and (e) of this section by the latest date an area within the planning region would be required to submit an implementation plan under paragraph (b) of this section, but in any event, no later than December 31, 2008.

(d) *What are the core requirements for the implementation plan for regional haze?* The State must address regional haze in each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State which may be affected by emissions from within the State. To meet the core requirements for regional haze for these areas, the State must submit an implementation plan containing the following plan elements and supporting documentation for all required analyses:

(1) *Reasonable progress goals.* For each mandatory Class I Federal area located within the State, the State must establish goals (expressed in deciviews) that provide for reasonable progress towards achieving natural visibility conditions. The reasonable progress goals must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period.

(i) In establishing a reasonable progress goal for any mandatory Class I Federal area within the State, the State must:

(A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal.

(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction measures needed to achieve it for the period covered by the implementation plan.

(ii) For the period of the implementation plan, 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 to 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.

(iii) In determining whether the State's goal for visibility improvement provides for reasonable progress towards natural visibility conditions, the Administrator will evaluate the demonstrations developed by the State pursuant to paragraphs (d)(1)(i) and (d)(1)(ii) of this section.

(iv) In developing each reasonable progress goal, the State must consult with those States which may reasonably be anticipated to cause or contribute to visibility impairment in the mandatory Class I Federal area. In any situation in which the State cannot agree with another such State or group of States that a goal provides for reasonable progress, the State must describe in its submittal the actions taken to resolve the disagreement. In reviewing the State's implementation plan submittal, the Administrator will take this information into account in determining whether the State's goal for visibility improvement provides for reasonable progress towards natural visibility conditions.

(v) The reasonable progress goals established by the State are not directly enforceable but will be considered by the Administrator in evaluating the adequacy of the measures in the implementation plan to achieve the progress goal adopted by the State.

(vi) The State may not adopt a reasonable progress goal that represents less visibility improvement than is expected to result from implementation of other requirements of the CAA during the applicable planning period.

(2) *Calculations of baseline and natural visibility conditions.* For each mandatory Class I Federal area located within the State, the State must determine the following visibility conditions (expressed in deciviews):

(i) Baseline visibility conditions for the most impaired and least impaired days. The period for establishing baseline visibility conditions is 2000 to 2004. Baseline visibility conditions must be calculated, using available monitoring data, by establishing the average degree of visibility impairment for the most and least impaired days for each calendar year from 2000 to 2004. The baseline visibility conditions are the average of these annual values. For mandatory Class I Federal areas without onsite monitoring data for 2000–2004, the State must establish baseline values using the most representative available monitoring data for 2000–2004, in consultation with the Administrator or his or her designee;

(ii) For an implementation plan that is submitted by 2003, the period for establishing baseline visibility conditions for the period of the first long-term strategy is the most recent 5-year period for which visibility monitoring data are available for the mandatory Class I Federal areas addressed by the plan. For mandatory Class I Federal areas without onsite monitoring data, the State must establish baseline values using the most representative available monitoring data, in consultation with the Administrator or his or her designee;

(iii) Natural visibility conditions for the most impaired and least impaired days. Natural visibility conditions must be calculated by estimating the degree of visibility impairment existing under natural conditions for the most impaired and least impaired days, based on available monitoring information and appropriate data analysis techniques; and

(iv)(A) For the first implementation plan addressing the requirements of paragraphs (d) and (e) of this section, the number of deciviews by which baseline conditions exceed natural visibility conditions for the most impaired and least impaired days; or

(B) For all future implementation plan revisions, the number of deciviews by which current conditions, as calculated under paragraph (f)(1) of this section, exceed natural visibility conditions for the most impaired and least impaired days.

(3) *Long-term strategy for regional haze.* Each State listed in § 51.300(b)(3) must submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for each mandatory Class I Federal area located outside the State which may be affected by emissions from the State. The long-term strategy must include enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals established by States having mandatory Class I Federal areas. In establishing its long-term strategy for regional haze, the State must meet the following requirements:

(i) Where the State has emissions that are reasonably anticipated to contribute to visibility impairment in any mandatory Class I Federal area located in another State or States, the State must consult with the other State(s) in order to develop coordinated emission management strategies. The State must consult with any other State having emissions that are reasonably anticipated to contribute to visibility impairment in any mandatory Class I Federal area within the State.

(ii) Where other States cause or contribute to impairment in a mandatory Class I Federal area, the State must demonstrate that it has included in its implementation plan all measures necessary to obtain its share of the emission reductions needed to meet the progress goal for the 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.

(iii) The State must document the technical basis, including modeling, monitoring and emissions information, on which the State is relying to determine its apportionment of emission reduction obligations necessary for achieving reasonable progress in each mandatory Class I Federal area it affects. The State may meet this requirement by relying on technical analyses developed by the regional planning organization and approved by all State participants. The State must identify the baseline emissions inventory on which its strategies are based. The baseline emissions inventory year is presumed to be the most recent year of the consolidate periodic emissions inventory.

(iv) 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.

(v) The State must consider, at a minimum, the following factors in developing its long-term strategy:

(A) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;

(B) Measures to mitigate the impacts of construction activities;

(C) Emissions limitations and schedules for compliance to achieve the reasonable progress goal;

(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 long-term strategy.

(4) *Monitoring strategy and other implementation plan requirements.* The State must submit with the implementation plan 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. This monitoring strategy must be coordinated with the monitoring strategy required in § 51.305 for reasonably attributable visibility impairment. Compliance with this requirement may be met through participation in the Interagency Monitoring of Protected Visual Environments network. The implementation plan must also provide for the following:

(i) The establishment of any additional monitoring sites or equipment needed to assess whether reasonable progress goals to address regional haze for all mandatory Class I Federal areas within the State are being achieved.

(ii) Procedures by which monitoring data and other information are used in determining the contribution of emissions from within the State to regional haze visibility impairment at mandatory Class I Federal areas both within and outside the State.

(iii) For a State with no mandatory Class I Federal areas, procedures by which monitoring data and other information are used in determining the contribution of emissions from within the State to regional haze visibility impairment at mandatory Class I Federal areas in other States.

(iv) The implementation plan must provide for the reporting of all visibility monitoring data to the Administrator at least annually for each mandatory Class I Federal area in the State. To the extent possible, the State should report visibility monitoring data electronically.

(v) A statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any mandatory Class I Federal area. The inventory must include emissions for a baseline year, emissions for the most recent year for which data are available, and estimates of future projected emissions. The State must also include a commitment to update the inventory periodically.

(vi) Other elements, including reporting, recordkeeping, and other measures, necessary to assess and report on visibility.

(e) *Best Available Retrofit Technology (BART) requirements for regional haze visibility impairment.* The State must submit an implementation plan containing emission limitations representing BART and schedules for compliance with BART for each BART-eligible source that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area, unless the State demonstrates that an emissions trading program or other alternative will achieve greater reasonable progress toward natural visibility conditions.

(1) To address the requirements for BART, the State must submit an implementation plan containing the following plan elements and include documentation for all required analyses:

(i) A list of all BART-eligible sources within the State.

(ii) A determination of BART for each BART-eligible source in the State that emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area. All such sources are subject to BART. This determination must be based on the following analyses:

(A) An analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source within the State subject to BART. In this analysis, the State must take into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use at the source, and the remaining useful life of the source; and

(B) An analysis of the degree of visibility improvement that would be achieved in each mandatory Class I Federal area as a result of the emission reductions achievable from all sources subject to BART located within the region that contributes to visibility impairment in the Class I area, based on the analysis conducted under paragraph (e)(1)(ii)(A) of this section.

(iii) If the State determines in establishing BART that technological or economic limitations on the applicability of measurement methodology to a particular source would make the imposition of an emission standard infeasible, it may instead prescribe a design, equipment, work practice, or other operational standard, or combination thereof, to require the application of BART. Such standard, to the degree possible, is to set forth the emission reduction to be achieved by implementation of such design, equipment, work practice or operation, and must provide for compliance by means which achieve equivalent results.

(iv) A requirement that each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.

(v) A requirement that each source subject to BART maintain the control equipment required by this subpart and establish procedures to ensure such equipment is properly operated and maintained.

(2) A State may opt to implement an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain BART. To do so, the State must demonstrate that this emissions trading program or other alternative measure will achieve greater reasonable progress than would be achieved through the installation and operation of BART. To make this demonstration, the State must submit an implementation plan containing the following plan elements and include documentation for all required analyses:

(i) A demonstration that the emissions trading program or other alternative measure will achieve greater reasonable progress than would have resulted from the installation and operation of BART at all sources subject to BART in the State. This demonstration must be based on the following:

(A) A list of all BART-eligible sources within the State.

(B) An analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each source within the State subject to BART. In this analysis, the State must take into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use at the source, and the remaining useful life of the source. The best system of continuous emission control technology and the above factors may be determined on a source category basis. The State may elect to consider both source-specific and category-wide information, as appropriate, in conducting its analysis.

(C) An analysis of the degree of visibility improvement that would be achieved in each mandatory Class I Federal area as a result of the emission reductions achievable from all such sources subject to BART located within the region that contributes to visibility impairment in the Class I area, based on the analysis conducted under paragraph (e)(2)(i)(B) of this section.

(ii) A demonstration that the emissions trading program or alternative measure will apply, at a minimum, to all BART-eligible sources in the State. Those sources having a federally enforceable emission limitation determined by the State and approved by EPA as meeting BART in accordance with § 51.302(c) or paragraph (e)(1) of this section do not need to meet the requirements of the emissions trading program or alternative measure, but may choose to participate if they meet the requirements of the emissions trading program or alternative measure.

(iii) A requirement that all necessary emission reductions take place during the period of the first long-term strategy for regional haze. To meet this requirement, the State must provide a detailed description of the emissions trading program or other alternative measure, including schedules for implementation, the emission reductions required by the program, all necessary administrative and technical procedures for implementing the program, rules for accounting and monitoring emissions, and procedures for enforcement.

(iv) A demonstration that the emission reductions resulting from the emissions trading program or other alternative measure will be surplus to those reductions resulting from measures adopted to meet requirements of the CAA as of the baseline date of the SIP.

(v) At the State's option, a provision that the emissions trading program or other alternative measure may include a geographic enhancement to the program to address the requirement under § 51.302(c) related to BART for reasonably attributable impairment from the pollutants covered under the emissions trading program or other alternative measure.

(3) After a State has met the requirements for BART or implemented emissions trading program or other alternative measure that achieve more reasonable progress than the installation and operation of BART, BART-eligible sources will be subject to the requirements of paragraph (d) of this section in the same manner as other sources.

(4) Any BART-eligible facility subject to the requirement under paragraph (e) of this section to install, operate, and maintain BART may apply to the Administrator for an exemption from that requirement. An application for an exemption will be subject to the requirements of § 51.303 (a)(2) through (h).

(f) *Requirements for comprehensive periodic revisions of implementation plans for regional haze.* Each State identified in § 51.300(b)(3) must revise and submit its regional haze implementation plan revision to EPA by July 31, 2018 and every ten years thereafter. In each plan revision, the State must evaluate and reassess all of the elements required in paragraph (d) of this section, taking into account improvements in monitoring data collection and analysis techniques, control technologies, and other relevant factors. In evaluating and reassessing these elements, the State must address the following:

(1) Current visibility conditions for the most impaired and least impaired days, and actual progress made towards natural conditions during the previous implementation period. The period for calculating current visibility conditions is the most recent five year period preceding the required date of the implementation plan submittal for which data are available. Current visibility conditions must be calculated based on the annual average level of visibility impairment for the most and least impaired days for each of these five years. Current visibility conditions are the average of these annual values.

(2) The effectiveness of the long-term strategy for achieving reasonable progress goals over the prior implementation period(s); and

(3) Affirmation of, or revision to, the reasonable progress goal in accordance with the procedures set forth in paragraph (d)(1) of this section. If the State established a reasonable progress goal for the prior period which provided a slower rate of progress than that needed to attain natural conditions by the year 2064, the State must evaluate and determine the reasonableness, based on the factors in paragraph (d)(1)(i)(A) of this section, of additional measures that could be adopted to achieve the degree of visibility improvement projected by the analysis contained in the first implementation plan described in paragraph (d)(1)(i)(B) of this section.

(g) *Requirements for periodic reports describing progress towards the reasonable progress goals.* Each State identified in § 51.300(b)(3) must submit a report to the Administrator every 5 years evaluating progress towards the reasonable progress goal for each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State which may be affected by emissions from within the State. The first progress report is due 5 years from submittal of the initial implementation plan addressing paragraphs (d) and (e) of this section. The progress reports must be in the form of implementation plan revisions that comply with the procedural requirements of § 51.102 and § 51.103. Periodic progress reports must contain at a minimum the following elements:

(1) A description of the status of implementation of all measures included in the implementation plan for achieving reasonable progress goals for mandatory Class I Federal areas both within and outside the State.

(2) A summary of the emissions reductions achieved throughout the State through implementation of the measures described in paragraph (g)(1) of this section.

(3) For each mandatory Class I Federal area within the State, the State must assess the following visibility conditions and changes, with values for most impaired and least impaired days expressed in terms of 5-year averages of these annual values.

(i) The current visibility conditions for the most impaired and least impaired days;

(ii) The difference between current visibility conditions for the most impaired and least impaired days and baseline visibility conditions;

(iii) The change in visibility impairment for the most impaired and least impaired days over the past 5 years;

(4) An analysis tracking the change over the past 5 years in emissions of pollutants contributing to visibility impairment from all sources and activities within the State. Emissions changes should be identified by type of source or activity. The analysis must be based on the most recent updated emissions inventory, with estimates projected forward as necessary and appropriate, to account for emissions changes during the applicable 5-year period.

(5) An assessment of any significant changes in anthropogenic emissions within or outside the State that have occurred over the past 5 years that have limited or impeded progress in reducing pollutant emissions and improving visibility.

(6) An assessment of whether the current implementation plan elements and strategies are sufficient to enable the State, or other States with mandatory Federal Class I areas affected by emissions from the State, to meet all established reasonable progress goals.

(7) A review of the State's visibility monitoring strategy and any modifications to the strategy as necessary.

(h) *Determination of the adequacy of existing implementation plan.* At the same time the State is required to submit any 5-year progress report to EPA in accordance with paragraph (g) of this section, the State must also take one of the following actions based upon the information presented in the progress report:

(1) If the State determines that the existing implementation plan requires no further substantive revision at this time in order to achieve established goals for visibility improvement and emissions reductions, the State must provide to the Administrator a negative declaration that further revision of the existing implementation plan is not needed at this time.

(2) If the State determines that the implementation plan is or may be inadequate to ensure reasonable progress due to emissions from sources in another State(s) which participated in a regional planning process, the State must provide notification to the Administrator and to the other State(s) which participated in the regional planning process with the States. The State must also collaborate with the other State(s) through the regional planning process for the purpose of developing additional strategies to address the plan's deficiencies.

(3) Where the State determines that the implementation plan is or may be inadequate to ensure reasonable progress due to emissions from sources in another country, the State shall provide notification, along with available information, to the Administrator.

(4) Where the State determines that the implementation plan is or may be inadequate to ensure reasonable progress due to emissions from sources within the State, the State shall revise its implementation plan to address the plan's deficiencies within one year.

(i) *What are the requirements for State and Federal Land Manager coordination*?

(1) By November 29, 1999, the State must identify in writing to the Federal Land Managers the title of the official to which the Federal Land Manager of any mandatory Class I Federal area can submit any recommendations on the implementation of this subpart including, but not limited to:

(i) Identification of impairment of visibility in any mandatory Class I Federal area(s); and

(ii) Identification of elements for inclusion in the visibility monitoring strategy required by § 51.305 and this section.

(2) The State must provide the Federal Land Manager with an opportunity for consultation, in person and at least 60 days prior to holding any public hearing on an implementation plan (or plan revision) for regional haze required by this subpart. This consultation must include the opportunity for the affected Federal Land Managers to discuss their:

(i) Assessment of impairment of visibility in any mandatory Class I Federal area; and

(ii) Recommendations on the development of the reasonable progress goal and on the development and implementation of strategies to address visibility impairment.

(3) In developing any implementation plan (or plan revision), the State must include a description of how it addressed any comments provided by the Federal Land Managers.

(4) The plan (or plan revision) must provide procedures for continuing consultation between the State and Federal Land Manager on the implementation of the visibility protection program required by this subpart, 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.

9. A new § 51.309 is added to subpart P to read as follows:

§ 51.309 Requirements related to the Grand Canyon Visibility Transport Commission.

(a) *What is the purpose of this section*? This section establishes the requirements for the first regional haze implementation plan to address regional haze visibility impairment in the 16 Class I areas covered by the Grand Canyon Visibility Transport Commission Report. For the years 2003 to 2018, certain States (defined in paragraph (b) of this section as Transport Region States) may choose to implement the Commission's recommendations within the framework of the national regional haze program and applicable requirements of the Act by complying with the provisions of this section, as supplemented by an approvable Annex to the Commission Report as required by paragraph (f) of this section. If a transport region State submits an implementation plan which is approved by EPA as meeting the requirements of this section, it will be deemed to comply with the requirements for reasonable progress for the period from approval of the plan to 2018.

(b) *Definitions.* For the purposes of this section:

(1) *16 Class I areas* means the following mandatory Class I Federal areas on the Colorado Plateau: Grand Canyon National Park, Sycamore Canyon Wilderness, Petrified Forest National Park, Mount Baldy Wilderness, San Pedro Parks Wilderness, Mesa Verde National Park, Weminuche Wilderness, Black Canyon of the Gunnison Wilderness, West Elk Wilderness, Maroon Bells Wilderness, Flat Tops Wilderness, Arches National Park, Canyonlands National Park, Capital Reef National Park, Bryce Canyon National Park, and Zion National Park.

(2) *Transport Region State* means one of the States that is included within the Transport Region addressed by the Grand Canyon Visibility Transport Commission (Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, and Wyoming).

(3) *Commission Report* means the report of the Grand Canyon Visibility Transport Commission entitled ''Recommendations for Improving Western Vistas,'' dated June 10, 1996.

(4) *Fire* means wildfire, wildland fire (including prescribed natural fire), prescribed fire, and agricultural burning conducted and occurring on Federal, State, and private wildlands and farmlands.

(5) *Milestone* means an average percentage reduction in emissions, expressed in tons per year, for a given year or for a period of up to 5 years ending in that year, compared to a 1990 actual emissions baseline.

(6) *Mobile Source Emission Budget* means the lowest level of VOC, NO_X, SO_2 elemental and organic carbon, and fine particles which are projected to occur in any area within the transport region from which mobile source emissions are determined to contribute significantly to visibility impairment in any of the 16 Class I areas.

(7) *Geographic enhancement* means a method, procedure, or process to allow a broad regional strategy, such as a milestone or backstop market trading program designed to achieve greater reasonable progress than BART for regional haze, to accommodate BART for reasonably attributable impairment.

(c) *Implementation Plan Schedule.* Each Transport Region State may meet the requirements of § 51.308(b) through (e) by electing to submit an implementation plan that complies with the requirements of this section. Each Transport Region State must submit an implementation plan addressing regional haze visibility impairment in the 16 Class I areas no later than December 31, 2003. A Transport Region State that elects not to submit an implementation plan that complies with the requirements of this section (or whose plan does not comply with all of the requirements of this section) is subject to the requirements of § 51.308 in the same manner and to the same extent as any State not included within the Transport Region.

(d) *Requirements of the first implementation plan for States electing to adopt all of the recommendations of the Commission Report.* Except as provided for in paragraph (e) of this section, each Transport Region State must submit an implementation plan that meets the following requirements:

(1) *Time period covered.* The implementation plan must be effective for the entire time period between December 31, 2003 and December 31, 2018.

(2) *Projection of visibility improvement.* For each of the 16 mandatory Class I areas located within the Transport Region State, the plan must include a projection of the improvement in visibility conditions (expressed in deciviews, and in any additional ambient visibility metrics deemed appropriate by the State) expected through the year 2018 for the most impaired and least impaired days, based on the implementation of all measures as required in the Commission report and the provisions in this section. The projection must be made in consultation with other Transport Region States with sources which may be reasonably anticipated to contribute to visibility impairment in the relevant Class I area. The projection may be based on a satisfactory regional analysis.

(3) *Treatment of clean-air corridors.* The plan must describe and provide for implementation of comprehensive emission tracking strategies for clean-air corridors to ensure that the visibility does not degrade on the least-impaired days at any of the 16 Class I areas. The strategy must include:

(i) An identification of clean-air corridors. The EPA will evaluate the State's identification of such corridors based upon the reports of the Commission's Meteorology Subcommittee and any future updates by a successor organization;

(ii) Within areas that are clean-air corridors, an identification of patterns of growth or specific sites of growth that could cause, or are causing, significant emissions increases that could have, or are having, visibility impairment at one or more of the 16 Class I areas.

(iii) In areas outside of clean-air corridors, an identification of significant emissions growth that could begin, or is beginning, to impair the quality of air in the corridor and thereby lead to visibility degradation for the least-impaired days in one or more of the 16 Class I areas.

(iv) If impairment of air quality in clean air corridors is identified pursuant to paragraphs (d)(3)(ii) and (iii) of this section, an analysis of the effects of increased emissions, including provisions for the identification of the need for additional emission reductions measures, and implementation of the additional measures where necessary.

(v) A determination of whether other clean air corridors exist for any of the 16 Class I areas. For any such clean air corridors, an identification of the necessary measures to protect against future degradation of air quality in any of the 16 Class I areas.

(4) *Implementation of stationary source reductions.* The first implementation plan submission must include:

(i) Monitoring and reporting of sulfur dioxide emissions. The plan submission must include provisions requiring the monitoring and reporting of actual stationary source sulfur dioxide emissions within the State. The monitoring and reporting data must be sufficient to determine whether a 13 percent reduction in actual stationary source sulfur dioxide emissions has occurred between the years 1990 and 2000, and whether milestones required by paragraph (f)(1)(i) of this section have been achieved for the transport region. The plan submission must provide for reporting of these data by the State to the Administrator. Where procedures developed under paragraph (f)(1)(ii) of this section and agreed upon by the State include reporting to a regional planning organization, the plan submission must provide for reporting to the regional planning body in addition to the Administrator.

(ii) Criteria and procedures for a market trading program. The plan must include the criteria and procedures for activating a market trading program or other program consistent with paragraph (f)(1)(i) of this section if an applicable regional milestone is exceeded, procedures for operation of the program, and implementation plan assessments and provisions for implementation plan assessments of the program in the years 2008, 2013, and 2018.

(iii) Provisions for activating a market trading program. Provisions to activate the market trading program or other program within 12 months after the emissions for the region are determined to exceed the applicable emission reduction milestone, and to assure that all affected sources are in compliance with allocation and other requirements within 5 years after the emissions for the region are determined to exceed the applicable emission reduction milestone.

(iv) Provisions for market trading program compliance reporting. If the market trading program has been activated, the plan submission must include provisions requiring the State to provide annual reports assuring that all sources are in compliance with applicable requirements of the market trading program.

(v) Provisions for stationary source NO_X and PM. The plan submission must include a report which assesses emissions control strategies for stationary source NO_X and PM, and the degree of visibility improvement that would result from such strategies. In the report, the State must evaluate and discuss the need to establish emission milestones for NO_X and PM to avoid any net increase in these pollutants from stationary sources within the transport region, and to support potential future development and implementation of a multipollutant and possibly multisource market-based program. The plan submission must provide for an implementation plan revision, containing any necessary long-term strategies and BART requirements for stationary source PM and NO_X (including enforceable limitations, compliance schedules, and other measures) by no later than December 31, 2008.

(5) *Mobile sources.* The plan submission must provide for:

(i) Statewide inventories of current annual emissions and projected future annual emissions of VO_c, NO_X, SO_2, elemental carbon, organic carbon, and fine particles from mobile sources for the years 2003 to 2018. The future year inventories must include projections for the year 2005, or an alternative year that is determined by the State to represent the year during which mobile source emissions will be at their lowest levels within the State.

(ii) A determination whether mobile source emissions in any areas of the State contribute significantly to visibility impairment in any of the 16 Class I Areas, based on the statewide inventory of current and projected mobile source emissions.

(iii) For States with areas in which mobile source emissions are found to contribute significantly to visibility impairment in any of the 16 Class I areas:

(A) The establishment and documentation of a mobile source emissions budget for any such area, including provisions requiring the State to restrict the annual VOC, NO_X, SO_2, elemental and organic carbon, and/or fine particle mobile source emissions to their projected lowest levels, to implement measures to achieve the budget or cap, and to demonstrate compliance with the budget.

(B) An emission tracking system providing for reporting of annual mobile source emissions from the State in the periodic implementation plan revisions required by paragraph (d)(10) of this section. The emission tracking system must be sufficient to determine the States' contribution toward the Commission's objective of reducing emissions from mobile sources by 2005 or an alternate year that is determined by the State to represent the year during which mobile source emissions will be at their lowest levels within the State, and to ensure that mobile source emissions do not increase thereafter.

(iv) Interim reports to EPA and the public in years 2003, 2008, 2013, and 2018 on the implementation status of the regional and local strategies recommended by the Commission Report to address mobile source emissions.

(6) *Programs related to fire.* The plan must provide for:

(i) Documentation that all Federal, State, and private prescribed fire programs within the State evaluate and address the degree visibility impairment from smoke in their planning and application. In addition the plan must include smoke management programs that include all necessary components including, but not limited to, actions to minimize emissions, evaluation of smoke dispersion, alternatives to fire, public notification, air quality monitoring, surveillance and enforcement, and program evaluation.

(ii) A statewide inventory and emissions tracking system (spatial and temporal) of VOC, NO_X, elemental and organic carbon, and fine particle emissions from fire. In reporting and tracking emissions from fire from within the State, States may use information from regional data-gathering and tracking initiatives.

(iii) Identification and removal wherever feasible of any administrative barriers to the use of alternatives to burning in Federal, State, and private prescribed fire programs within the State.

(iv) Enhanced smoke management programs for fire that consider visibility effects, not only health and nuisance objectives, and that are based on the criteria of efficiency, economics, law, emission reduction opportunities, land management objectives, and reduction of visibility impact.

(v) Establishment of annual emission goals for fire, excluding wildfire, that will minimize emission increases from fire to the maximum extent feasible and that are established in cooperation with States, tribes, Federal land management agencies, and private entities.

(7) *Area sources of dust emissions from paved and unpaved roads.* The plan must include an assessment of the impact of dust emissions from paved and unpaved roads on visibility conditions in the 16 Class I Areas. If such dust emissions are determined to be a significant contributor to visibility impairment in the 16 Class I areas, the State must implement emissions management strategies to address the impact as necessary and appropriate.

(8) *Pollution prevention.* The plan must provide for:

(i) An initial summary of all pollution prevention programs currently in place, an inventory of all renewable energy generation capacity and production in use, or planned as of the year 2002 (expressed in megawatts and megawatt-hours), the total energy generation capacity and production for the State, the percent of the total that is renewable energy, and the State's anticipated contribution toward the renewable energy goals for 2005 and 2015, as provided in paragraph (d)(8)(vi) of this section.

(ii) Programs to provide incentives that reward efforts that go beyond compliance and/or achieve early compliance with air-pollution related requirements.

(iii) Programs to preserve and expand energy conservation efforts.

(iv) The identification of specific areas where renewable energy has the potential to supply power where it is now lacking and where renewable energy is most cost-effective.

(v) Projections of the short- and long-term emissions reductions, visibility improvements, cost savings, and secondary benefits associated with the renewable energy goals, energy efficiency and pollution prevention activities.

(vi) A description of the programs relied on to achieve the State's contribution toward the Commission's goal that renewable energy will comprise 10 percent of the regional power needs by 2005 and 20 percent by 2015, and a demonstration of the progress toward achievement of the renewable energy goals in the years 2003, 2008, 2013, and 2018. This description must include documentation of the potential for renewable energy resources, the percentage of renewable energy associated with new power generation projects implemented or planned, and the renewable energy generation capacity and production in use and planned in the State. To the extent that it is not feasible for a State to meet its contribution to the regional renewable energy goals, the State must identify in the progress reports the measures implemented to achieve its contribution and explain why meeting the State's contribution was not feasible.

(9) *Implementation of additional recommendations.* The plan must provide for implementation of all other recommendations in the Commission report that can be practicably included as enforceable emission limits, schedules of compliance, or other enforceable measures (including economic incentives) to make reasonable progress toward remedying existing and preventing future regional haze in the 16 Class I areas. The State must provide a report to EPA and the public in 2003, 2008, 2013, and 2018 on the progress toward developing and implementing policy or strategy options recommended in the Commission Report.

(10) *Periodic implementation plan revisions.* Each Transport Region State must submit to the Administrator periodic reports in the years 2008, 2013, and 2018. The progress reports must be in the form of implementation plan revisions that comply with the procedural requirements of § 51.102 and § 51.103.

(i) The report will assess the area for reasonable progress as provided in this section for mandatory Class I Federal area(s) located within the State and for mandatory Class I Federal area(s) located outside the State which may be affected by emissions from within the State. This demonstration may be based on assessments conducted by the States and/or a regional planning body. The progress reports must contain at a minimum the following elements:

(A) A description of the status of implementation of all measures included in the implementation plan for achieving reasonable progress goals for mandatory Class I Federal areas both within and outside the State.

(B) A summary of the emissions reductions achieved throughout the State through implementation of the measures described in paragraph (d)(10)(i)(A) of this section.

(C) For each mandatory Class I Federal area within the State, an assessment of the following: the current visibility conditions for the most impaired and least impaired days; the difference between current visibility conditions for the most impaired and least impaired days and baseline visibility conditions; the change in visibility impairment for the most impaired and least impaired days over the past 5 years.

(D) An analysis tracking the change over the past 5 years in emissions of pollutants contributing to visibility impairment from all sources and activities within the State. Emissions changes should be identified by type of source or activity. The analysis must be based on the most recent updated emissions inventory, with estimates projected forward as necessary and appropriate, to account for emissions changes during the applicable 5-year period.

(E) An assessment of any significant changes in anthropogenic emissions within or outside the State that have occurred over the past 5 years that have limited or impeded progress in reducing pollutant emissions and improving visibility.

(F) An assessment of whether the current implementation plan elements and strategies are sufficient to enable the State, or other States with mandatory Federal Class I areas affected by emissions from the State, to meet all established reasonable progress goals.

(G) A review of the State's visibility monitoring strategy and any modifications to the strategy as necessary.

(ii) At the same time the State is required to submit any 5-year progress report to EPA in accordance with paragaph (d)(10)(i) of this section, the State must also take one of the following actions based upon the information presented in the progress report:

(A) If the State determines that the existing implementation plan requires no further substantive revision at this time in order to achieve established goals for visibility improvement and emissions reductions, the State must provide to the Administrator a negative declaration that further revision of the existing implementation plan is not needed at this time.

(B) If the State determines that the implementation plan is or may be inadequate to ensure reasonable progress due to emissions from sources in another State(s) which participated in a regional planning process, the State must provide notification to the Administrator and to the other State(s) which participated in the regional planning process with the States. The State must also collaborate with the other State(s) through the regional planning process for the purpose of developing additional strategies to address the plan's deficiencies.

(C) Where the State determines that the implementation plan is or may be inadequate to ensure reasonable progress due to emissions from sources in another country, the State shall provide notification, along with available information, to the Administrator.

(D) Where the State determines that the implementation plan is or may be inadequate to ensure reasonable progress due to emissions from within the State, the State shall develop additional strategies to address the plan deficiencies and revise the implementation plan no later than one year from the date that the progress report was due.

(11) *State planning and interstate coordination.* In complying with the requirements of this section, States may include emission reductions strategies that are based on coordinated implementation with other States. Examples of these strategies include economic incentive programs and transboundary emissions trading programs. The implementation plan must include documentation of the technical and policy basis for the individual State apportionment (or the procedures for apportionment throughout the trans-boundary region), the contribution addressed by the State's plan, how it coordinates with other State plans, and compliance with any other appropriate implementation plan approvability criteria. States may rely on the relevant technical, policy and other analyses developed by a regional entity (such as the Western Regional Air Partnership) in providing such documentation. Conversely, States may elect to develop their own programs without relying on work products from a regional entity.

(12) *Tribal implementation.* Consistent with 40 CFR Part 49, tribes within the Transport Region may implement the required visibility programs for the 16 Class I areas, in the same manner as States, regardless of whether such tribes have participated as members of a visibility transport commission.

(e) *States electing not to implement the commission recommendations.* Any Transport Region State may elect not to implement the Commission recommendations set forth in paragraph (d) of this section. Such States are required to comply with the timelines and requirements of § 51.308. Any Transport Region State electing not to implement the Commission recommendations must advise the other States in the Transport Region of the nature of the program and the effect of the program on visibility-impairing emissions, so that other States can take this information into account in developing programs under this section.

(f) *Annex to the Commission Report.* (1) A Transport Region State may choose to comply with the provisions of this section and by doing so shall satisfy the requirements of § 51.308(b) through (e) only if the Grand Canyon Visibility Transport Commission (or a regional planning body formed to implement the Commission recommendations) submits a satisfactory annex to the Commission Report no later than October 1, 2000. To be satisfactory, the Annex must contain the following elements:

(i) The annex must contain quantitative emission reduction milestones for stationary source sulfur dioxide emissions for the reporting years 2003, 2008, 2013 and 2018. The milestones must provide for steady and continuing emission reductions for the 2003–2018 time period consistent with the Commission's definition of reasonable progress, its goal of 50 to 70 percent reduction in sulfur dioxide emissions from 1990 actual emission levels by 2040, applicable requirements under the CAA, and the timing of implementation plan assessments of progress and identification of deficiencies which will be due in the years 2008, 2013, and 2018. The emission reduction milestones must be shown to provide for greater reasonable progress than would be achieved by application of best available retrofit technology (BART) pursuant to § 51.308(e)(2) and would be approvable in lieu of BART.

(ii) The annex must contain documentation of the market trading program or other programs to be implemented pursuant to paragraph (d)(4) of this section if current programs and voluntary measures are not sufficient to meet the required emission reduction milestones. This documentation must include model rules, memoranda of understanding, and other documentation describing in detail how emission reduction progress will be monitored, what conditions will require the market trading program to be activated, how allocations will be performed, and how the program will operate.

(2) The Commission may elect, at the same time it submits the annex, to make recommendations intended to demonstrate reasonable progress for other mandatory Class I areas (beyond the original 16) within the Transport Region States, including the technical and policy justification for these additional mandatory Class I Federal areas in accordance with the provisions of paragraph (g) of this section.

(3) The EPA will publish the annex upon receipt. If EPA finds that the annex meets the requirements of paragraph (f)(1) of this section and assures reasonable progress, then, after public notice and comment, will amend the requirements of paragraph (d)(4) of this section to incorporate the provisions of the annex within 1 year after EPA receives the annex. If EPA finds that the annex does not meet the requirements of paragraph (f)(1) of this section, or does not assure reasonable progress, or if EPA finds that the annex is not received, then each Transport Region State must submit an implementation plan for regional haze meeting all of the requirements of § 51.308.

(4) In accordance with the provisions under paragraph (f)(1) of this section, the annex may include a geographic enhancement to the program provided for in paragraph (d)(4) of this section to address the requirement under § 51.302(c) related to Best Available Retrofit Technology for reasonably attributable impairment from the pollutants covered by the milestones or the backstop market trading program. The geographic enhancement program may include an appropriate level of reasonably attributable impairment which may require additional emission reductions over and above those achieved under the milestones defines in paragraph (f)(1)(i) of this section.

(g) *Additional Class I areas.* The following submittals must be made by Transport Region States implementing the provisions of this section as the basis for demonstrating reasonable progress for additional Class I areas in the Transport Region States. If a Transport Region State submits an implementation plan which is approved by EPA as meeting the requirements of this section, it will be deemed to comply with the requirements for reasonable progress for the period from approval of the plan to 2018.

(1) In the plan submitted for the 16 Class I areas no later than December 31, 2003, a declaration indicating whether other Class I areas will be addressed under § 51.308 or paragraphs (g)(2) and (3) of this section.

(2) In a plan submitted no later than December 31, 2008, provide a demonstration of expected visibility conditions for the most impaired and least impaired days at the additional mandatory Class I Federal area(s) based on emissions projections from the long-term strategies in the implementation plan. This demonstration may be based on assessments conducted by the States and/or a regional planning body.

(3) In a plan submitted no later than December 31, 2008, provide revisions to the plan submitted under paragraph (c) of this section, including provisions to establish reasonable progress goals and implement any additional measures necessary to demonstrate reasonable progress for the additional mandatory Federal Class I areas. These revisions must comply with the provisions of § 51.308(d)(1) through (4).

(4) The following provisions apply for Transport Region States establishing reasonable progress goals and adopting any additional measures for Class I areas other than the 16 Class I areas under paragraphs (g)(2) and (3) of this section.

(i) In developing long-term strategies pursuant to § 51.308(d)(3), the State may build upon the strategies implemented under paragraph (d) of this section, and take full credit for the visibility improvement achieved through these strategies.

(ii) The requirement under § 51.308(e) related to Best Available Retrofit Technology for regional haze is deemed to be satisfied for pollutants addressed by the milestones and backstop trading program if, in establishing the emission reductions milestones under paragraph (f) of this section, it is shown that greater reasonable progress will be achieved for these Class I areas than would be achieved through the application of source-specific BART emission limitations under § 51.308(e)(1).

(iii) The Transport Region State may consider whether any strategies necessary to achieve the reasonable progress goals required by paragraph (g)(3) of this section are incompatible with the strategies implemented under paragraph (d) of this section to the extent the State adequately demonstrates that the incompatibility is related to the costs of the compliance, the time necessary for compliance, the energy and no air quality environmental impacts of compliance, or the remaining useful life of any existing source subject to such requirements.

10. In the sections listed in the first column remove the reference listed in the middle column and add the reference listed in the third column in its place:

Section	Remove	Add
51.301(v)	Section 303	§ 51.303
51.302(c)(2)(i)	Section 305	§ 51.305
51.302(c)(2)(i)	Section 306	§ 51.306
51.302(c)(2)(i)	Section 300(a)	§ 51.300(a)
51.302(c)(4)(i)	Section 304(b)	§ 51.304(b)
51.303(a)(1)	Section 302	§ 51.302
51.303(c)	Section 303	§ 51.303
51.303(d)	Section 303	§ 51.303
51.303(g)	Section 303	§ 51.303
51.303(h)	Section 303	§ 51.303
51.304(c)	Section 306(c)	§ 51.306(c)
51.306(a)(1)	Section 300(a)	§ 51.300(a)
51.306(c)(6)	Section 303	§ 51.303
51.307(b)(1)	Section 304	§ 51.304
51.307(b)(1)	Section 304(d)	§ 51.304(d)
51.307(c)	Section 300(a)	§ 51.300(a)

[FR Doc. 99–13941 Filed 6–30–99; 8:45 am]

BILLING CODE 6560–50–U

ATTACHMENT E

Summary of 40 CFR Sections 51.302 through 51.307

40 CFR Part 51 Subpart P – Protection of Visibility, Sections 51.302 through 51.307

The requirements in 40 CFR sections 51.302-51.307 relate primarily to the reasonably attributable visibility impairment rules originally promulgated in 1980. Therefore, they are included as an attachment to the section in the report discussing the regional haze rule.

1 40 CFR 51.302 Implementation control strategies for reasonably attributable visibility impairment.

This section establishes SIP revision procedures, state and FLM coordination, and general plan requirements for reasonably attributable visibility impairment.

The SIP revision procedures require each state to have submitted a SIP by September 2, 1981 to address the reasonably attributable visibility impairment requirements. The section also requires states to coordinate with FLMs for recommendations and consultations on the proposed SIP and implementation of the visibility protection program.

General plan requirements include: a long-term strategy to make reasonable progress toward the national goal; an assessment of visibility impairment and a discussion of how each element of the plan relates to the preventing of future or remedying of existing impairment of visibility in Class I areas within the state; and emission limitations representing BART and schedules for compliance with BART for each existing stationary facility subject to the rule.

How does this provision relate to BART at taconite facilities?

This provision also requires the MPCA to identify and analyze for BART each existing stationary facility which may reasonably be anticipated to cause or contribute to impairment of visibility in a Class I area. If a FLM certifies that there exists reasonably attributable impairment of visibility in a Class I area, then the state sets limits or other requirements as described below:

(1) The state must identify and analyze for BART each existing stationary facility which may reasonably be anticipated to cause or contribute to impairment of visibility in any Class I area where the impairment is reasonably attributable to that existing stationary facility.
(2) If the state determines that technological or economic limitations on the applicability of measurement methodology to a particular existing stationary facility would make the imposition of an emission standard infeasible it may instead prescribe a design, equipment, work practice, or other operational standard, or combination thereof, to require the application of BART. Such standard will set forth the emission reduction to be achieved by implementation of such design, equipment, work practice or operation, and must provide for compliance by means which achieve equivalent results.

This provision requires taconite facilities to apply BART as expeditiously as practicable, but not later than five years after plan approval. In addition, taconite facilities are required to analyze BART when new technology for control of the pollutant becomes available if:

- The pollutant is emitted by that existing stationary facility,
- Controls representing BART for the pollutant have not previously been required under this subpart, and

- The impairment of visibility in any Class I area is reasonably attributable to the emissions of that pollutant.

2 40 CFR 51.303 Exemptions from control.

Under this section, any existing stationary facility required to install, operate, and maintain BART may apply for an exemption from that requirement. The application must document the impact of the source's emissions on visibility in any Class I area and demonstrate that the source does not or will not, by itself or in combination with other sources, emit any air pollutants which may be reasonably anticipated to cause or contribute to significant visibility impairment in any Class I area.

The exemption application requirements and approval procedure is outlined below:
(1) The exemption application must include MPCA concurrence and it may include an initial recommendation or other comments from the FLMs,
(2) Notice and opportunity for a public hearing,
(3) EPA may then grant or deny the application,
(4) FLMs must concur with the EPA determination before the exemption is finally granted.

How does this provision relate to BART at taconite facilities?

This provision allows taconite facilities to apply for an exemption from BART if it can demonstrate that it does not emit any air pollutants that may be reasonably anticipated to cause or contribute to significant visibility impairment in any Class I area.

3 40 CFR 51.304 Identification of integral vistas.

This section allows FLMs to identify any integral vista by December 31, 1985. An integral vista is a view perceived from within the Class I area of a specific landmark or panorama located outside the boundary of the Class I area.

How does this provision relate to BART at taconite facilities?

Since FLMs may no longer identify an integral vista and since there are none in Minnesota, this provision has no impact on taconite facilities.

4 40 CFR 51.305 Monitoring for reasonably attributable visibility impairment.

This section requires each state to include in the plan a strategy for evaluating reasonably attributable visibility impairment in any Class I area by visual observation or other appropriate monitoring techniques. States should follow EPA's June 1999 Visibility Guidance document in developing this strategy.

How does this provision relate to BART at taconite facilities?

This provision requires the MPCA to include in the SIP a strategy for evaluating reasonably attributable visibility impairment in Class I areas by visual observation or other appropriate monitoring techniques. To date, the Minnesota SIP does not address a visibility monitoring strategy.

5 40 CFR 51.306 Long-term strategy requirements for reasonably attributable visibility impairment.

This section requires each plan to include a long-term (10-15 years) strategy for making reasonable progress toward the national goal and discusses factors the state must consider in the development of the strategy. This section also describes the required elements of and schedule for review as well as report requirements.

How does this provision relate to BART at taconite facilities?

This provision requires the MPCA to include in the SIP a long-term (10-15 years) strategy for each Class I area in Minnesota and each Class I area located outside the state which may be affected by sources within the state for making reasonable progress toward the national goal. It also establishes the criteria of and timeline for periodic review and revision of the strategy. Note that the long-term strategy is separate from the regional haze plan required by 40 CFR 51.308(b) and (c).

6 40 CFR 51.307 New source review.

This section discusses the requirements that a plan must provide for in the event of any new major stationary source or major modification that would be constructed in an area that is designated attainment or unclassified. Requirements include:

- Notification to affected FLMs of a proposed new major stationary source or major modification that may affect visibility in any Class I area
- Advanced notification of a permit application of a source that may affect visibility in the state
- Consideration of any analysis performed by the FLM that a proposed new major stationary source or major modification may have an adverse impact on visibility in any Class I area.

This section also requires that the plan provide for the review of any new major stationary source or major modification that may have an impact on any integral vista of a Class I area or that proposes to locate in an area classified as nonattainment that may have an impact on visibility in any Class I area.

How does this provision relate to BART at taconite facilities?

Because no integral vistas have been established in the United States and no nonattainment areas are present in northern Minnesota where a new or modified taconite plant would be located, this provision has little impact on the taconite industry.

ATTACHMENT F

July 20, 2001, Federal Register Notice – Proposed Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations; Proposed Rule

Federal Register

Friday,
July 20, 2001

Part III

Environmental Protection Agency

40 CFR Part 51

Proposed Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 51

[FRL–6934–4]

Proposed Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The purpose of this proposal is to request comment on EPA's proposed guidelines for implementation of the best available retrofit technology (BART) requirements under the regional haze rule which was published on July 1, 1999 (64 FR 35714). We propose to add the guidelines as appendix Y to 40 CFR part 51. We propose to add regulatory text requiring that these guidelines be used for addressing BART determinations under the regional haze rule. In addition, we are proposing one revision to guidelines issued in 1980 for facilities contributing to ''reasonably attributable'' visibility impairment.

DATES: We are requesting written comments by September 18, 2001. The EPA has scheduled two public hearings on this proposed rule. The first public hearing will be held on August 21 in Arlington, Virginia. The second public hearing will be held on August 27 in Chicago, Illinois. (See following section for times and addresses.)

ADDRESSES: *Docket.* Information related to the BART guidelines is available for inspection at the Air and Radiation Docket and Information Center, docket number A–2000–28. The docket is located at the U.S. Environmental Protection Agency, 401 M Street, SW, Room M–1500, Washington, DC 20460, telephone (202) 260–7548. The docket is available for public inspection and copying between 8:00 a.m. and 5:30 p.m., Monday through Friday, excluding legal holidays. A reasonable fee may be charged for copying.

You should submit comments on today's proposal and the materials referenced herein (in duplicate if possible) to the Air and Radiation Docket and Information Center (6102), Attention: Docket No. A–2000–28, U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue, NW, Washington, DC 20460. You may also submit comments to EPA by electronic mail at the following address: A-and-R-Docket@epamail.epa.gov. Electronic comments must be submitted as an ASCII file avoiding the use of special characters and any form of encryption. All comments and data in electronic form must be identified by the docket number [A–2000–28]. Electronic comments on this proposed rule also may be filed online at many Federal Depository Libraries.

Public Hearings. The first public hearing on this proposed rule will be held on August 21 at 10:00 am at the Crowne Plaza Hotel, 1489 Jefferson Davis Highway, Arlington, VA 22202. The hotel is located near the Crystal City metro stop. The second public hearing will be held on August 27 at 10:00 am at the Metcalfe Federal Building, Room 331, 77 West Jackson Boulevard, Chicago, IL 60604.

If you wish to attend either public hearing or wish to present oral testimony, please send notification no later than one week prior to the date of the public hearing to Ms. Nancy Perry, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, MD–15, Research Triangle Park, NC 27711, telephone (919) 541–5628, e-mail *perry.nancy@epa.gov.*

Oral testimony will be limited to 5 minutes each. The hearing will be strictly limited to the subject matter of the proposal, the scope of which is discussed below. Any member of the public may file a written statement by the close of the comment period. Written statements (duplicate copies preferred) should be submitted to Docket No. A–2000–28 at the address listed above for submitting comments. The hearing schedule, including lists of speakers, will be posted on EPA's webpage at *http://www.epa.gov/air/visibility/whatsnew.html.* A verbatim transcript of the hearings and written statements will be made available for copying during normal working hours at the Air and Radiation Docket and Information Center at the address listed above.

FOR FURTHER INFORMATION CONTACT: Tim Smith (telephone 919–541–4718), Mail Drop 15, EPA, Air Quality Strategies and Standards Division, Research Triangle Park, North Carolina, 27711. Internet address: smith.tim@epa.gov.

SUPPLEMENTARY INFORMATION: We are providing the public with the opportunity to comment on EPA's Proposed BART Guidelines and the accompanying regulatory text.

Table of Contents

I. Background on BART Guidelines

A. Commitment in the Preamble to the Regional Haze Rule

The EPA included in the final regional haze rule a requirement for BART for certain large stationary sources put in place between 1962 and 1977. We discuss these requirements in detail in the preamble to the final rule (see 64 FR 35737–35743). The regulatory requirements for BART are codified in 40 CFR 51.308(e). In the preamble, we committed to issuing further guidelines to clarify the requirements of the BART provision. The purpose of this notice is to provide the public with an opportunity to comment on the draft guidelines and the accompanying regulatory text.

B. Statutory Requirement for BART Guidelines

Section 169A(b)(1) of the Clean Air Act (CAA) requires EPA to provide guidelines to States on the implementation of the visibility program. Moreover, the last sentence of section 169A(b) states:

> In the case of a fossil-fuel fired generating powerplant having a capacity in excess of 750 megawatts, the emission limitations required under this paragraph shall be determined pursuant to guidelines, promulgated by the Administrator under paragraph (1)

We interpret this statutory requirement as clearly requiring EPA to publish BART guidelines and to require that States follow the guidelines in establishing BART emission limitations for power plants with a total capacity exceeding the 750 megawatt cutoff. The statute is less clear regarding whether the guidelines must be used for sources other than 750 megawatt power plants; however, today's proposed rule would require States to use the guidelines for all of the 26 categories. We believe it is reasonable that consistent, rigorous approaches be used for all BART source categories. In addition, we believe it is important to provide for consistent approaches to identifying the sources in the remaining categories which are BART-eligible. We request comment on whether the regional haze rule should: (1) Require use of the guidelines only for 750 megawatt utilities, with the guidelines applying as guidance for the remaining categories, or (2)require use of the guidelines for all of the affected source categories.

II. Proposed Amendments to Part 51

We propose:

(1) BART guidelines, to be added as appendix Y to 40 CFR part 51,

(2) regulatory text, to be added as sub-paragraph 51.308(e)(1)(C), requiring the use of the guidelines.

Overview of Proposed Appendix Y

We discuss the following general topics in appendix Y, which are organized into the following sections:

—*Introduction.* Section I provides an overview of the BART requirement in the regional haze rule and in the CAA, and an overview of the guidelines.

—*Identification of BART-eligible sources.* Section II is a step-by-step process for identifying BART-eligible sources.

—*Identification of sources subject to BART.* Sources ''subject to BART'' are those BART-eligible sources which ''emit a pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any Class I area.'' We discuss considerations for identifying sources subject to BART in section III of the proposed appendix Y.

—*Engineering analysis.* For each source subject to BART, the next step is to conduct an engineering analysis of emissions control alternatives. This step requires the identification of available, technically feasible, retrofit technologies, and for each technology identified, analysis of the cost of compliance, and the energy and non-air quality environmental impacts, taking into account the remaining useful life and existing control technology present at the source. For each source, a ''best system of continuous emission reduction'' is selected based upon this engineering analysis. Guidelines for the engineering analysis are described in section IV of the proposed appendix Y.

—*Cumulative air quality analysis.* The rule requires a cumulative analysis of the degree of visibility improvement that would be achieved in each Class I area as a result of the emissions reductions achievable from all sources subject to BART. The establishment of BART emission limits must take into account the cumulative impact overall from the emissions reductions from all of the source-specific ''best technologies'' identified in the engineering analysis. Considerations for this cumulative air quality analysis are discussed in section V.

—*Emission limits.* Considering the engineering analysis and the cumulative air quality analysis, States must establish enforceable limits, including a deadline for compliance, for each source subject to BART. Considerations related to these limits and deadlines are discussed in section VI.

—*Trading program alternative.* General guidance on how to develop an emissions trading program alternative to BART is contained in section VII of the guidance. (Note that more comprehensive guidance for emission trading programs generally is described in Section VII).

Regulatory Text

The proposed regulatory text would require that States follow the guidelines for all BART determinations required under the regional haze rule. We request public comment on all provisions of the guidelines and on the accompanying regulatory text.

III. Revision to 1980 BART Guidelines for ''Reasonably Attributable'' Visibility Impairment

As noted above, the primary purpose of today's proposed rule is to provide BART guidelines for the regional haze program. In addition, however, we are making limited revisions to longstanding guidelines for BART under the 1980 visibility regulations for localized visibility impairment that is ''reasonably attributable'' to one or a few sources.[1] The visibility regulations require that States must use a 1980 guidelines document when conducting BART analyses for certain power plants for reasonably attributable visibility impairment. The regulatory text for this requirement is found in 40 CFR 51.302(c)(4)(iii), as follows:

(iii) BART must be determined for fossil-fuel fired generating plants having a total generating capacity in excess of 750 megawatts pursuant to ''Guidelines for Determining Best Available Retrofit Technology for Coal-fired Power Plants and Other Existing Stationary Facilities'' (1980), which is incorporated by reference, exclusive of appendix E, which was published in the **Federal Register** on February 6, 1980 (45 FR 8210). It is EPA publication No. 450/3–80–009b and is for sale from the U.S. Department of Commerce, National Technical Information Service, 5285 Port Royal Road, Springfield, Virginia 22161. It is also available for inspection at the Office of the Federal Register Information Center, 800 North Capitol NW., suite 700, Washington, DC.

While the analytical process set forth in these guidelines is still generally acceptable for conducting BART analyses for ''reasonably attributable'' visibility impairment, there are statements in the 1980 BART Guidelines that could be read to indicate that the new source performance standards (NSPS) may be considered to represent the maximum achievable control for existing sources. While this may have been the case in 1980 (e.g., the NSPS for sulfur dioxide (SO_2) from boilers had been recently issued in June 1979), the maximum achievable control levels for recent plant retrofits have exceeded NSPS levels. Thus, in order to ensure that there is no confusion regarding how the 1980 guidelines should be interpreted, EPA has included the following discussion in today's action and proposes limited clarifying changes to the visibility regulations.

In various sections of the 1980 guideline, the discussion indicates that the NSPS in 1980 was considered to generally represent the most stringent option these sources could install as BART (i.e., maximum achievable level of control). See, e.g., 1980 BART Guidelines at pp. 8, 11 and 21. For example, a flowchart in the 1980 guidelines indicates that if States establish a BART emission limitation equivalent to NSPS for the source, then the State would not need to conduct a full-blown analysis of control alternatives. See, 1980 BART Guidelines at p. 8. Similarly, the visibility analysis described in the guideline assumes as a starting point the level of controls currently achieved by the NSPS. See, 1980 Guideline at p. 11. In the 20-year period since these guidelines were developed, there have been advances in SO_2 control technologies that have significantly increased the level of control that is feasible, while costs per ton of SO_2 controlled have declined.

[1] U.S. Environmental Protection Agency, *Guidelines for Determining Best Available Retrofit Technology for Coal-fired Power Plants and Other Existing Stationary Facilities,* EPA–450/3–80–009b, Office of Air Quality Planning and Standards, Research Triangle Park, N.C., November 1980 (1980 BART Guidelines).

This is demonstrated by a number of recent retrofits or binding agreements to retrofit coal-fired power plants in the western United States. These plants include: Hayden (CO), Navajo (AZ), Centralia (WA), and Mohave (NV). These cases have shown that control options exist which can achieve a significantly greater degree of control than the 70 percent minimum required by the NSPS for power plants emitting SO_2 at less than 0.60 lb/million Btu heat input. These retrofits have achieved, or are expected to achieve, annual SO_2 reductions in the 85 to 90 percent range. Additionally, an EPA report [2] published in October 2000 shows that the SO_2 removal for flue gas desulfurization systems installed in the 1990s is commonly 90 percent or more for both wet and dry scrubbers, well above the minimum 70 percent control required by the 1979 NSPS.[3]

Given the advances in control technology that have occurred over the past 20 years, we believe that it should be made clear that the BART analyses for reasonably attributable visibility impairment should not be based on an assumption that the NSPS level of control represents the maximum achievable level of control. While it is possible that a detailed analysis of the BART factors could result in the selection of a NSPS level of control, we believe that States should only reach this conclusion based upon an analysis of the full range of control options, including those more stringent than a NSPS level of control. In sum, all ''reasonably attributable'' BART analyses should consider control levels more stringent than NSPS, including maximum achievable levels, and evaluate them in light of the statutory factors.

IV. Administrative Requirements

In preparing any proposed rule, EPA must meet the administrative requirements contained in a number of statutes and executive orders. In this section of the preamble, we discuss how today's regulatory proposal for BART guidelines addresses these administrative requirements.

[2] U.S. Environmental Protection Agency, *Controlling SO_2 Emissions: A Review of Technologies,* EPA–600/R–00–093, Office of Research and Development, National Risk Management Research Laboratory, Research Triangle Park, NC, October 2000, pp 32–34.

[3] Note also that part II of the 1980 BART guidelines includes an analysis of 90 percent control for three power plants burning low-sulfur coal.

A. Regulatory Planning and Review by the Office of Management and Budget (OMB) (Executive Order 12866)

Under Executive Order 12866 (58 FR 51735, October 4, 1993) the Agency must determine whether the regulatory action is ''significant'' and, therefore, subject to OMB review and the requirements of the Executive Order. The Order defines ''significant regulatory action'' as one that is likely to result in a rule that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impacts of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, it has been determined that this rule is a ''significant regulatory action'' and EPA has submitted it to OMB for review. The drafts of rules submitted to OMB, the documents accompanying such drafts, written comments thereon, written responses by EPA, and identification of the changes made in response to OMB suggestions or recommendations are available for public inspection at EPA's Air and Radiation Docket and Information Center (Docket Number A–2000–28).

Because today's guidelines clarify, and do not change, the existing rule requirements of the regional haze rule, the guidelines do not have any effect on the Regulatory Impact Analysis (RIA) that was previously prepared for the regional haze rule. This RIA is available in the docket for the regional haze rule (A–95–38). As part of the analyses included in this RIA, we provided an estimate of the potential cost of control to BART sources that is an average of the costs associated with the least stringent illustrative progress goal (1.0 deciview reduction over a 15-year period) and the most stringent illustrative progress goal (10 percent deciview reduction over a 10-year period). The annual cost of control to BART sources associated with the final Regional Haze rulemaking in 2015, the year for which impacts are projected, is $72 million (1990 dollars).

This estimate of the control costs for BART sources for the year 2015 was calculated after taking into account a regulatory baseline projection for the year 2015. The baseline for these calculations included control measures estimated to be needed for partial attainment of the PM and ozone NAAQS issued in 1997. These baseline estimates were contained in an analysis prepared for the RIA for the PM and ozone NAAQS, and are summarized in the RIA for the regional haze rulemaking. As a result, in this RIA, we calculated relatively small impacts for BART, in part because the baseline for the analysis assumed a substantial degree of emissions control for BART-eligible sources in response to the national ambient air quality standards (NAAQS) for $PM_{2.5}$.

The EPA provided a benefits analysis of the emissions reductions associated with the four illustrative progress goals in the RIA for the final rulemaking. This benefits analysis is also incremental to partial attainment of the PM and ozone NAAQS issued in 1997. We did not, however, include a benefits analysis for the reductions from controls specific to the potentially affected BART sources. For more information on the benefit analysis for the final Regional Haze rulemaking, please refer to the RIA in the public docket for the regional haze rule (Docket A–95–38).

B. Regulatory Flexibility Act

The EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with this proposed rule. The EPA has also determined that this proposed rule would not have a significant impact on a substantial number of small entities because the rule would not establish requirements applicable to small entities.

The Regulatory Flexibility Act (5 U.S.C. 601 et seq.) (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act (Pub. L. No.104–121) (SBREFA), provides that whenever an agency is required to publish a general notice of proposed rulemaking, it must prepare and make available an initial regulatory flexibility analysis, unless it certifies that the proposed rule, if promulgated, will not have ''a significant economic impact on a substantial number of small entities.'' 5 U.S.C. 605(b). Courts have interpreted the RFA to require a regulatory flexibility analysis only when small entities will be subject to the requirements of the rule. See *Motor and Equip. Mfrs. Ass'n* v. *Nichols,* 142 F.3d 449 (D.C. Cir. 1998); *United Distribution Cos.* v. *FERC,* 88 F.3d 1105, 1170 (D.C.

Cir. 1996); *Mid-Tex Elec. Co-op, Inc.* v. *FERC,* 773 F.2d 327, 342 (D.C. Cir. 1985) (agency's certification need only consider the rule's impact on entities subject to the rule).

Similar to the discussion in the proposed and final regional haze rules, the proposed BART guidelines would not establish requirements applicable to small entities. The proposed rule would apply to States, not to small entities. The BART requirements in the regional haze rule require BART determinations for a select list of major stationary sources defined by section 169A(g)(7) of the CAA. However, as noted in the proposed and final regional haze rules, the State's determination of BART for regional haze involves some State discretion in considering a number of factors set forth in section 169A(g)(2), including the costs of compliance. Further, the final regional haze rule allows States to adopt alternative measures in lieu of requiring the installation and operation of BART at these major stationary sources. As a result, the potential consequences of the BART provisions of the regional haze rule (as clarified in today's proposed guidelines) at specific sources are speculative. Any requirements for BART will be established by State rulemakings. The States would accordingly exercise substantial intervening discretion in implementing the BART requirements of the regional haze rule and today's proposed guidelines. In addition, we note that most sources potentially affected by the BART requirements in section 169A of the CAA are large industrial plants. Of these, we would expect few, if any, to be considered small entities. We request comment on issues regarding small entities that States might encounter when implementing the BART provision.

For today's proposed BART guidelines, EPA certifies that the guidelines and accompanying regulatory text would not have a significant impact on a substantial number of small entities.

C. Paperwork Reduction Act—Impact on Reporting Requirements

The information collection requirements in today's proposal clarify, but do not modify, the information collection requirements for BART. Reporting requirements related to BART requirements were included in an Information Collection Request document that was prepared by EPA (ICR No. 1813.02) and a copy may be obtained from Sandy Farmer, by mail at Collection Strategies Division; U.S. EPA (2822) 1200 Pennsylvania Avenue, NW., Washington, DC 20460, by email at *farmer.sandy@epa.gov,* or by calling (202) 260–2740. A copy may also be downloaded off the Internet at *http://www.epa.gov/icr.* The information requirements are not effective until OMB approves them.

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 OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9 and 48 CFR chapter 15.

Comments are requested on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques. Send comments on the ICR to the Director, Collection Strategies Division; U.S. Environmental Protection Agency (2822); 1200 Pennsylvania Ave., NW., Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th St., NW., Washington, DC 20503, marked ''Attention: Desk Officer for EPA.'' Include the ICR number in any correspondence.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4) (UMRA), 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 the UMRA, 2 U.S.C. 1532, EPA generally must prepare a written statement, including a cost-benefit analysis, for any proposed or final rule that ''includes any Federal mandate that may result in the expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $100,000,000 or more * * * in any one year.'' A ''Federal mandate'' is defined under section 421(6), 2 U.S.C. 658(6), to include a ''Federal intergovernmental mandate'' and a ''Federal private sector mandate.'' A ''Federal intergovernmental mandate,'' in turn, is defined to include a regulation that ''would impose an enforceable duty upon State, local, or tribal governments,'' section 421(5)(A)(i), 2 U.S.C. 658 (5)(A)(i), except for, among other things, a duty that is ''a condition of Federal assistance,'' section 421(5)(A)(i)(I). A ''Federal private sector mandate'' includes a regulation that ''would impose an enforceable duty upon the private sector,'' with certain exceptions, section 421(7)(A), 2 U.S.C. 658(7)(A).

Before promulgating an EPA rule for which a written statement is needed under section 202 of the UMRA, section 205, 2 U.S.C. 1535, of the 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.

By proposing to release BART guidelines and to require their use, EPA is not directly establishing any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments. Thus, EPA is not obligated to develop under section 203 of the UMRA a small government agency plan.

Further, EPA carried out consultations with the governmental entities affected by this rule in a manner consistent with the intergovernmental consultation provisions of section 204 of the UMRA.

The EPA also believes that because today's proposal provides States with substantial flexibility, the proposed rule meets the UMRA requirement in section 205 to select the least costly and burdensome alternative in light of the statutory mandate for BART. The proposed rule provides States with the flexibility to establish BART based on certain criteria, one of which is the costs of compliance. The proposed rule also provides States with the flexibility to adopt alternatives, such as an emissions trading program, in lieu of requiring BART. The BART guidelines therefore, inherently provides for adoption of the least costly, most cost-effective, or least-burdensome alternative that achieves the objective of the rule.

The EPA is not reaching a final conclusion as to the applicability of the requirements of UMRA to this rulemaking action. It is questionable whether a requirement to submit a State Implementation Plan (SIP) revision constitutes a Federal mandate. The obligation for a State to revise its SIP that arises out of sections 110(a), 169A and 169B of the CAA is not legally enforceable by a court of law and, at most, is a condition for continued receipt of highway funds. Therefore, it is possible to view an action requiring such a submittal as not creating any enforceable duty within the meaning of section 421(5)(A)(i) of UMRA (2 U.S.C. 658 (5)(A)(i)). Even if it did, the duty could be viewed as falling within the exception for a condition of Federal assistance under section 421(5)(A)(i)(I) of UMRA (2 U.S.C. 658(5)(A)(i)(I)). As noted earlier, however, notwithstanding these issues, the discussion in section 2 and the analysis in chapter 8 of the RIA constitutes the UMRA statement that would be required by UMRA if its statutory provisions applied, and EPA has consulted with governmental entities as would be required by UMRA. Consequently, it is not necessary for EPA to reach a conclusion as to the applicability of the UMRA requirements.

E. Environmental Justice—Executive Order 12898

Executive Order 12898 requires that each Federal agency make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minorities and low-income populations. The requirements of Executive Order 12898 have been previously addressed to the extent practicable in the RIA cited above, particularly in chapters 2 and 9 of the RIA.

F. Protection of Children From Environmental Health Risks and Safety Risks—Executive Order 13045

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 EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency. The EPA interprets Executive Order 13045 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under section 5–501 of the Order has the potential to influence the regulation. The BART guidelines are not subject to Executive Order 13045 because they do not establish an environmental standard intended to mitigate health or safety risks.

G. Executive Order 13132: Federalism

Executive Order 13132, entitled Federalism (64 FR 43255, August 10, 1999), 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'' are 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 Section 6 of 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. The 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.

The EPA concludes that this rule will not have substantial federalism implications, as specified in section 6 of Executive Order 13132 (64 FR 43255, August 10, 1999), because it will not directly impose significant new requirements on State and local governments, nor substantially alter the relationship or the distribution of power and responsibilities between States and the Federal government.

Although EPA has determined that section 6 of Executive Order 13132 does not apply, EPA nonetheless consulted with a broad range of State and local officials during the course of developing this proposed rule. These included contacts with the National Governors Association, National League of Cities, National Conference of State Legislatures, U. S. Conference of Mayors, National Association of Counties, Council of State Governments, International City/County Management Association, and National Association of Towns and Townships.

H. Executive Order 13084: Consultation and Coordination With Indian Tribal Governments

On November 6, 2000, the President issued Executive Order 13175 (65 FR 67249) entitled ''Consultation and Coordination with Indian Tribal Governments.'' Executive Order 13175 took effect on January 6, 2001, and revokes Executive Order 13084 (Tribal Consultation) as of that date. The EPA developed this proposed rule, however, during the period when EO 13084 was in effect; thus, EPA addressed tribal considerations under EO 13084. The EPA will analyze and fully comply with the requirements of EO 13175 before promulgating the final rule.

Under Executive Order 13084, EPA may not issue a regulation that is not required by statute that significantly or uniquely affects the communities of Indian tribal governments, and that imposes substantial direct compliance costs on those communities, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by the tribal governments, or EPA consults with those governments. If EPA complies by consulting, Executive Order 13084 requires EPA to provide to OMB, in a separately identified section of the preamble to the rule, a description of the extent of EPA's prior consultation with representatives of affected tribal governments, a summary of the nature of their concerns, and a statement supporting the need to issue the regulation. In addition, Executive Order 13084 requires EPA to develop an effective process permitting elected officials and other representatives of Indian tribal governments ''to provide meaningful and timely input in the development of regulatory policies on matters that significantly or uniquely affect their communities.''

Today's proposed rule does not significantly or uniquely affect the communities of Indian tribal governments. This proposed action does not involve or impose any requirements that directly affect Indian tribes. Under EPA's tribal authority rule, tribes are not required to implement CAA programs but, instead, have the opportunity to do so. Accordingly, the requirements of section 3(b) of Executive Order 13084 do not apply to this rule.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Pub. L. No.

104–113, § 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This action does not involve technical standards. Therefore, EPA did not consider the use of any voluntary consensus standards.

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

Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355 (May 22, 2001)), provides that agencies shall prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget, a Statement of Energy Effects for certain actions identified as ''significant energy actions.'' Section 4(b) of Executive Order 13211 defines ''significant energy actions'' as ''any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: (1)(i) that is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.'' Under Executive Order 13211, a Statement of Energy Effects is a detailed statement by the agency responsible for the significant energy action relating to: (i) any adverse effects on energy supply, distribution, or use including a shortfall in supply, price increases, and increased use of foreign supplies) should the proposal be implemented, and (ii) reasonable alternatives to the action with adverse energy effects and the expected effects of such alternatives on energy supply, distribution, and use. While this rulemaking is a ''significant regulatory action'' under Executive Order 12866, EPA has determined that this rulemaking is not a significant energy action because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

As discussed above in Unit IV.A, EPA provided an estimate of the potential cost of control to BART sources in the RIA for the regional haze rule for the year 2015. As specified in the CAA, these BART sources include certain utility steam electric plants and sources in 25 additional industrial source categories. In 1999, EPA estimated that BART would impose additional costs of $72 million per year (in 1990 dollars) in 2015 on affected utility and industrial sources.[4] It is expected that these annual costs will be lower in 2015 than currently projected due to continued improvements in scrubber operation and design. Included in the total cost is an estimate that roughly 35 utility units built between the years 1962 and 1977 would be required to install additional control equipment, typically scrubbers.

Consistent with the RIA, we have looked at the potential energy impacts associated with scrubbers. About 60 percent of the overall $72 million estimate, or about $40 million, was a result of scrubber cost calculations. These scrubber cost calculations are based on cost models which determine three types of costs for scrubbers: (1) Annualized capital costs, (2) fixed operation and maintenance costs, and (3) variable operating and maintenance costs. The cost models for variable operating and maintenance costs took into account the energy needs of the scrubber, which was assumed to be 2.0% of the electricity generated by a plant (or approximately 15,000 Megawatt-hours per year (MW–h/yr) for a 100 MW scrubber).[5] Although BART requirements may also be achieved with other control strategies and techniques (such as emission trading, or switching types of fuels used to produce power), these scrubber cost calculations can be used to provide an order of magnitude estimate of possible energy costs. The EPA estimates that of the total annual cost estimate of $40 million for scrubbers, about 20 to 35 percent, or about $9 million to $15 million, would be variable operating and maintenance costs. The energy costs for the scrubbers would be some fraction of this $9 to $15 million estimate, which also includes other elements such as the costs of reagents and disposal. Applying this energy use to the roughly 35 utility units requires a total of 525 million MW–h/yr, or 0.5 billion Kilowatt-hours/year (kWh–yr) of energy, which is valued at $17 million.[6]

The EPA also believes that an annual cost of $40 million for the electric utility sector for the year 2015 and beyond would not result in significant changes in electricity or fuel prices, or in significant changes in the consumption of energy.

For non-utility sources, the costs of the BART requirements may result from installing, operating and maintaining pollution control equipment or from other control strategies and techniques. As with utilities, a fraction of these costs in some cases would be related to the energy used to operate the pollution control equipment, thus increasing the overall demand for energy and fuels; however, such impacts are usually a small fraction of the overall annualized costs of control equipment. Thus, EPA believes that the energy costs for non-utility categories would be a relatively small fraction of the $72 million cost estimate. The EPA believes that the overall effects on energy supply and use for a small fraction of $72 million would be trivial, and that this would not significantly affect the price or supply of energy.

Therefore, we conclude that based on the analysis above that the BART requirements of the Regional Haze Rule will have a minimal impact, if any, on energy prices, or on the supply, distribution, or use of energy.

K. Guidelines for BART Determinations Under the Regional Haze Rule

We are proposing to adopt guidelines for BART determinations under the regional haze rule. The guidelines and areas on which comment is requested are described below. After we receive comments on these guidelines, we will add them to 40 CFR part 51 as appendix Y.

Guidelines for BART Determinations Under the Regional Haze Rule

Table of Contents

[4] *Regulatory Impact Analysis for the Regional Haze Rule.* U.S. EPA, Office of Air Quality Planning and Standards. April 22, 1999. Unit 6.6.3, pp. 6–40 through 6–42.

[5] U.S. Environmental Protection Agency, *Controlling SO2 Emissions: A Review of Technologies,* EPA–600/R–00–093, Office of Research and Development, National Risk Management Research Laboratory, Research Triangle Park, NC, October 2000, pp 32–34.

[6] Based on wholesale energy prices for the year 2000.

I. Introduction and Overview

A. What Is the Purpose of the Guidelines?

The Clean Air Act (CAA), in sections 169A and 169B, contains requirements for the protection of visibility in 156 scenic areas across the United States. To meet the CAA's requirements, EPA recently published regulations to protect against a particular type of visibility impairment known as ''regional haze.'' The regional haze rule is found in this part (40 CFR part 51), in §§ 51.300 through 51.309. These regulations require, in § 51.308(e), that certain types of existing stationary sources of air pollutants install best available retrofit technology (BART). The guidelines are designed to help States and others (1) identify those sources that must comply with the BART requirement, and (2) determine the level of control technology that represents BART for each source.

B. What Does the CAA Require Generally for Improving Visibility?

Section 169A of the CAA, added to the CAA by the 1977 amendments, requires States to protect and improve visibility in certain scenic areas of national importance. The scenic areas protected by section 169A are called ''mandatory Class I Federal Areas.'' In these guidelines, we refer to these as ''Class I areas.'' There are 156 Class I areas, including 47 national parks (under the jurisdiction of the Department of Interior—National Park Service), 108 wilderness areas (under the jurisdiction of the Department of Interior–Fish and Wildlife Service or the Department of Agriculture—US Forest Service), and one International Park (under the jurisdiction of the Roosevelt-Campobello International Commission). The Federal Agency with jurisdiction over a particular Class I area is referred to in the CAA as the Federal Land Manager. A complete list of the Class I areas is contained in 40 CFR part 81, §§ 81.401 through 81.437, and you can find a map of the Class I areas at the following internet site: *http://www.epa.gov/ttn/oarpg/t1/fr—notices/classimp.gif*

The CAA establishes a national goal of eliminating man-made visibility impairment from the Class I areas where visibility is an important value. As part of the plan for achieving this goal, the visibility protection provisions in the CAA mandate that EPA issue regulations requiring that States adopt measures in their State Implementation Plans (SIPs), including long-term strategies, to provide for reasonable progress towards this national goal. The CAA also requires States to coordinate with the Federal Land Managers as they develop their strategies for addressing visibility.

C. What Is the BART Requirement in the CAA?

Under section 169A(b)(2)(A) of the CAA, States must require certain existing stationary sources to install BART. The BART requirement applies to ''major stationary sources'' from one of 26 identified source categories which have the potential to emit 250 tons per year or more of any air pollutant. The CAA requires only sources which were put in place during a specific 15-year time interval to install BART. The BART requirement applies to sources that existed as of the date of the 1977 CAA amendments (that is, August 7, 1977) but which had not been in operation for more than 15 years (that is, not in operation as of August 7, 1962).

The CAA requires BART when any source meeting the above description ''emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility'' in any Class I area. In identifying a level of control as BART, States are required by section 169A(g) of the CAA to consider:

—The costs of compliance,
—The energy and non-air quality environmental impacts of compliance,
—Any existing pollution control technology in use at the source,
—The remaining useful life of the source, and
—The degree of visibility improvement which may reasonably be anticipated from the use of BART.

The CAA further requires States to make BART emission limitations part of their SIPs. As with any SIP revision, this will be a public process that provides an opportunity for public comment and judicial review of any decision by EPA to approve or disapprove the revision.

D. What Types of Visibility Problems Does EPA Address in Its Regulations?

The EPA addressed the problem of visibility in two phases. In 1980, EPA published regulations addressing what we termed ''reasonably attributable'' visibility impairment. Reasonably attributable visibility impairment is the result of emissions from one or a few sources that are generally located in close proximity to a specific Class I area. The regulations addressing reasonably attributable visibility impairment are published in §§ 51.300 through 51.307.

On July 1, 1999, EPA amended these regulations to address the second, more common, type of visibility impairment known as ''regional haze.'' Regional haze is the result of the collective contribution of many sources over a broad region. The regional haze rule regulations slightly modified 40 CFR 51.300 through 51.307, including the addition of a few definitions in § 51.301, and added new §§ 51.308 and 51.309.

E. What Are the BART Requirements in EPA's Regional Haze Regulations?

In the July 1, 1999 rulemaking, EPA added a BART requirement for regional haze. You will find the BART requirements in 40 CFR 51.308(e)(1). Definitions of terms used in 40 CFR 51.308(e)(1) are found in § 51.301.

As we discuss in detail in these guidelines, the regional haze rule codifies and clarifies the BART provisions in the CAA. The rule requires that States identify and list ''BART-eligible sources,'' that is, that States identify and list those sources that fall within one of 26 source categories, that were put in place during the 15-year window of time from 1962 to 1977, and that have potential emissions greater than 250 tons per year. Once the State has identified the BART-eligible sources, the next step is to identify those BART eligible sources that may ''emit any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility.'' Under the rule, a source which fits this description is ''subject to BART.'' For each source subject to BART, States must identify the level of control representing BART based upon the following analyses:

— First, paragraph 308(e)(1)(ii)(A) provides that States must identify the best system of continuous emission control technology for each source subject to BART taking into account the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, and the remaining useful life of the source.
— Second, paragraph 308(e)(1)(ii)(B), provides that States must conduct an analysis of the degree of visibility improvement that would be achieved from all sources subject to BART that are within a geographic area that contributes to visibility impairment in any protected Class I area.

Once a State has identified the level of control representing BART (if any), it must establish an emission limit representing BART and must ensure compliance with that requirement no later than 5 years after EPA approves the SIP. States are allowed to establish design, equipment, work practice or other operational standards when limitations on measurement technologies make emission standards infeasible.

F. Do States Have an Alternative to Imposing Controls on Specific Facilities?

States are given the option under 40 CFR 51.308(e)(2) to adopt an alternative approach to imposing controls on a case-by-case basis for each source subject to BART. However, while States may instead adopt alternative measures, such as an emissions trading program, 40 CFR 51.308(e)(2)(i) requires States to provide a demonstration that any such alternative will achieve greater ''reasonable progress'' than would have resulted from installation of BART from all sources subject to BART. Such a demonstration must include:

— a list of all BART-eligible sources;
— an analysis of the best system of continuous emission control technology available for all sources subject to BART, taking into account the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, and the remaining useful life of the source. Unlike the analysis for BART under 40 CFR 51.308(e)(1), which requires that these factors be considered on a case-by-case basis, States may consider these factors on a category-wide basis, as appropriate, in evaluating alternatives to BART;
— an analysis of the degree of visibility improvement that would result from the alternative program in each protected Class I area.

States must make sure that a trading program or other such measure includes all BART-eligible sources, unless a source has installed BART, or plans to install BART consistent with 51.308(e)(1).[1] A trading program also may include additional sources. 40 CFR 51.308(e)(2) also requires that States include in their SIPs details on how they would implement the emission trading program or other alternative measure. States must provide a detailed description of the program including schedules for compliance, the emissions reductions that they will require, the administrative and technical procedures for implementing the program, rules for accounting and monitoring emissions, and procedures for enforcement.

G. What Is Included in the Guidelines?

In the guidelines, we provide procedures States must use in implementing the regional haze BART requirements on a source-by-source basis, as provided in 40 CFR 51.308(e)(1). We address general topics related to development of a trading program or other alternative allowed by 40 CFR 51.308(e)(2), but we will address most of the details of guidance for trading programs in separate guidelines.

The BART analysis process, and the contents of this guidance, are as follows:

[1] As noted in the preamble to the regional haze rule, States need not include a BART-eligible source in the trading program if the source already has installed BART-level pollution control technology and the emission limit is a federally enforceable requirement (64 FR 35742). We clarify in these guidelines that States may also elect to allow a source the option of installing BART-level controls within the 5-year period for compliance with the BART requirement [see section VI of these guidelines] rather than participating in a trading program.

–*Identification of all BART-eligible sources.* Section II of this guidance outlines a step-by-step process for identifying BART-eligible sources.
–*Identification of sources subject to BART.* As noted above, sources ''subject to BART'' are those BART-eligible sources which ''emit a pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any Class I area.'' We discuss considerations for identifying sources subject to BART in section III of the guidance.
–*Engineering analysis.* For each source subject to BART, the next step is to conduct an engineering analysis of emissions control alternatives. This step requires the identification of available, technically feasible, retrofit technologies, and for each technology identified, analysis of the cost of compliance, and the energy and non-air quality environmental impacts, taking into account the remaining useful life and existing control technology present at the source. For each source, a ''best system of continuous emission reduction'' will be selected based upon this engineering analysis. Guidelines for the engineering analysis are described in section IV of this guidance.
—*Cumulative air quality analysis.* The rule requires a cumulative analysis of the degree of visibility improvement that would be achieved in each Class I area as a result of the emissions reductions achievable from *all* sources subject to BART. The establishment of BART emission limits must take into account the cumulative impact overall from the emissions reductions from all of the source-specific ''best technologies'' identified in the engineering analysis. Considerations for this cumulative air quality analysis are discussed in section V of this guidance.
—*Emissions limits.* Considering the engineering analysis and the cumulative air quality analysis, States must establish enforceable limits, including a deadline for compliance, for each source subject to BART. Considerations related to these limits and deadlines are discussed in section VI of the guidance.
—*Considerations in establishing a trading program alternative.* General guidance on how to develop an emissions trading program alternative is contained in section VII of the guidance.

H. Who Is the Target Audience for the Guidelines?

The guidelines are written primarily for the benefit of State, local and tribal agencies to satisfy the requirements for including the BART determinations and emission limitations in their SIPs or tribal implementation plans (TIPs). Throughout the guidelines, which are written in a question and answer format, we ask questions ''How do I * * *?'' and answer with phrases ''you should * * *, you must* * *'' The ''you'' means a State, local or tribal agency conducting the analysis.[2] We recognize, however, that agencies may prefer to require source owners to assume part of the analytical burden, and that there will be differences in how the supporting information is collected and documented.

II. How To Identify BART-Eligible Sources

This section provides guidelines on how you identify BART-eligible sources. A BART-eligible source is an existing stationary source in 26 listed categories which meets criteria for startup dates and potential emissions.

A. What Are the Steps In Identifying BART-Eligible Sources?

Figure 1 shows the steps for identifying whether the source is a ''BART eligible source:''

Step 1: Identify the emission units in BART categories,

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

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

[2] In order to account for the possibility that BART-eligible sources could go unrecognized, we recommend that you adopt requirements placing a responsibility on source owners to self-identify if they meet the criteria for BART-eligible sources.

Figure 1. How to determine whether a source is BART-eligible:

Step 1: Identify emission units in the BART categories

Does the plant contain emissions units in one or more of the 26 source categories? ➜ No ➜ Stop
➜ Yes ➜ Proceed to Step 2

Step 2: Identify the start-up dates of these emission units

Do any of these emissions units meet the following two tests?

In existence on August 7, 1977
AND
Began operation after August 7, 1962

➜ No ➜ Stop
➜ Yes ➜ Proceed to Step 3

Step 3: Compare the potential emissions from these emission units to the 250 ton/yr cutoff

Identify the "stationary source" that includes the emission units you identified in Step 2.

Add the current potential emissions from all the emission units identified in Steps 1 and 2 that are included within the "stationary source" boundary.

Are the potential emissions from these units 250 tons per year or more for any visibility-impairing pollutant?

➜ No ➜ Stop

➜ Yes ➜ These emissions units comprise the "BART-eligible source."

1. Step 1: Identify Emission Units in the BART Categories

The BART requirement only applies to sources in specific categories listed in the CAA. The BART requirement does not apply to sources in other source categories, regardless of their emissions. The listed categories are:

(1) Fossil-fuel fired steam electric plants of more than 250 million British thermal units (BTU) per hour heat input,
(2) Coal cleaning plants (thermal dryers),
(3) Kraft pulp mills,
(4) Portland cement plants,
(5) Primary zinc smelters,
(6) Iron and steel mill plants,
(7) Primary aluminum ore reduction plants,
(8) Primary copper smelters,
(9) Municipal incinerators capable of charging more than 250 tons of refuse per day,
(10) Hydrofluoric, sulfuric, and nitric acid plants,
(11) Petroleum refineries,
(12) Lime plants,
(13) Phosphate rock processing plants,
(14) Coke oven batteries,
(15) Sulfur recovery plants,
(16) Carbon black plants (furnace process),
(17) Primary lead smelters,
(18) Fuel conversion plants,
(19) Sintering plants,

(20) Secondary metal production facilities,

(21) Chemical process plants,

(22) Fossil-fuel boilers of more than 250 million BTUs per hour heat input,

(23) Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels,

(24) Taconite ore processing facilities,

(25) Glass fiber processing plants, and

(26) Charcoal production facilities.

Some plant locations may have emission units from more than one category, and some emitting equipment may fit into more than one category. Examples of this situation are sulfur recovery plants at petroleum refineries, coke oven batteries and sintering plants at steel mills, and chemical process plants at refineries. For Step 1, you identify *all* of the emissions units at the plant that fit into one or more of the listed categories. You do not identify emission units in other categories.

Example: A mine is collocated with a electric steam generating unit and a coal cleaning plant. You would identify emission units associated with the electric steam generating unit and the coal cleaning plant, because they are listed categories but not the mine, because coal mining is not a listed category.

The category titles are generally clear in describing the types of equipment to be listed. Most of the category titles are very broad descriptions that encompass all emission units associated with a plant site (for example, ''petroleum refining'' and ''kraft pulp mills''). In addition, this same list of categories appears in the PSD regulations, for example in 40 CFR 52.21. States and source owners need not revisit any interpretations of the list made previously for purposes of the PSD program. We provide the following clarifications for a few of the category titles and we request comment on whether there are any additional source category titles for which EPA should provide clarification in the final guidelines:

—*''Steam electric plants of more than 250 million BTU/hr heat input.''* Because the category refers to ''plants,'' boiler capacities must be aggregated to determine whether the 250 million BTU/hr threshold is reached.

Example: Stationary source includes a steam electric plant with three 100 million BTU/hr boilers. Because the aggregate capacity exceeds 250 million BTU/hr for the ''plant,'' these boilers would be identified in Step 2.

''Steam electric plants'' includes combined cycle turbines because of their incorporation of heat recovery steam generators. Simple cycle turbines should not be considered ''steam electric plants'' because they typically do not make steam.

—*''Fossil-fuel boilers of more than 250 million BTU/hr heat input.''* The EPA proposes two options for interpreting this source category title. The first option is the approach used in the regulations for prevention of significant deterioration (PSD). In the PSD regulations, this same statutory language has been interpreted in regulatory language to mean ''fossil fuel boilers (or combinations thereof) totaling more than 250 million British thermal units per hour heat input.'' The EPA proposes that this same interpretation be used for BART as well. Thus, as in the example above, you would aggregate boiler capacities to determine whether the 250 million BTU/hr threshold is reached.

Under the second option, this category would be interpreted to cover only those boilers that are individually greater than 250 million BTU/hr. This approach would result in differing language from the PSD program. It is possible, however, that different approaches may be justified. The PSD program ensures that new source projects do not circumvent the program by constructing several boilers with capacities lower than 250 million BTU/hr. Because the BART program affects only sources already in existence as of the date of the 1977 CAA amendments, there may be a lesser need to aggregate boilers that are individually less than 250 million BTU/hr. The EPA requests comment on both options proposed above.

—*Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels.* The 300,000 barrel cutoff refers to total facility-wide tank capacity for tanks that were put in place within the 1962–1977 time period, and includes gasoline and other petroleum-derived liquids.

—''*Phosphate rock processing plants.''* This category descriptor is broad, and includes all types of phosphate rock processing facilities, including elemental phosphorous plants as well as fertilizer production plants.

—''*Charcoal production facilities.''* In a letter sent to EPA on October 11, 2000, the National Association of Manufacturers (NAM) noted that there is some limited legislative history on this source category list. Specifically, there is discussion in the Congressional Record from July 29, 1976 (Cong. Record S. 12781–12784) which identifies a study in the 1970s by the Research Corporation of New England (the TRC report). The Congressional Record contains a table extracted from the TRC report that identifies 190 source categories considered in developing a list of 28 categories that led to the 26 categories eventually listed in the CAA. In its October 11, 2000 letter, NAM suggests that the Congressional Record and the TRC report are relevant to the interpretation of the source category ''charcoal production facilities.'' While EPA does not believe that the TRC report or table contain any information that would suggest subdividing this category, EPA has included the NAM letter and the cited passage from the Congressional Record in the docket for this proposed rule. The EPA requests comment on whether and how the information cited by NAM is relevant to the interpretation of this or other categories.

2. Step 2: Identify the Start-Up Dates of the Emission Units

Emissions units listed under Step 1 are BART-eligible only if they were ''in existence'' on August 7, 1977 but were not ''in operation'' before August 7, 1962.

What does ''in existence on August 7, 1977'' mean?

The regulation defines ''in existence'' to mean that:

> The owner or operator has obtained all necessary preconstruction approvals or permits required by Federal, State, or local air pollution emissions and air quality laws or regulations and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into binding agreements or contractual obligations, which cannot be canceled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time. See 40 CFR 51.301.

Thus, the term ''in existence'' means the same thing as the term ''commence construction'' as that term is used in the PSD regulations. See 40 CFR 51.165(a)(1)(xvi) and 40 CFR 52.21(b)(9). Thus, an emissions unit could be ''in existence'' according to this test even if it did not begin operating until several years later.

Example: The owner or operator obtained necessary permits in early 1977 and entered into binding construction agreements in June 1977. Actual on-site construction began in late 1978, and construction was completed in mid-1979. The source began operating in September 1979. The emissions unit *was* ''in existence'' as of August 7, 1977.

We note that emissions units of this size for which construction commenced

AFTER August 7, 1977 (i.e., were not ''in existence'' on August 7, 1977) were subject to major new source review (NSR) under the PSD program. Thus, the August 7, 1977 ''in existence'' test is essentially the same thing as the identification of emissions units that were grandfathered from the NSR review requirements of the 1977 CAA amendments.

Finally, we note that sources are not BART eligible if the only change at the plant was the addition of pollution controls. For example, if the only change at a copper smelter during the 1962 through 1977 time period was the addition of acid plants for the reduction of SO_2 emissions, these emission controls would not by themselves trigger a BART review.

What does ''in operation before August 7, 1962'' mean?

An emissions unit that meets the August 7, 1977 ''in existence'' test is not BART-eligible if it was in operation before August 7, 1962. ''In operation'' is defined as ''engaged in activity related to the primary design function of the source.'' This means that a source must have begun actual operations by August 7, 1962 to satisfy this test.

Example: The owner or operator entered into binding agreements in 1960. Actual on-site construction began in 1961, and construction was complete in mid-1962. The source began operating in September 1962. The emissions unit *was not* ''in operation'' before August 7, 1962 and is therefore subject to BART.

What is a ''reconstructed source?''

Under a number of CAA programs, an existing source which is completely or substantially rebuilt is treated as a new source. Such ''reconstructed'' sources are treated as new sources as of the time of the reconstruction. Consistent with this overall approach to reconstructions, the definition of BART-eligible facility (reflected in detail in the definition of ''existing stationary facility'') includes consideration of sources that were in operation before August 7, 1962, but were reconstructed during the August 7, 1962 to August 7, 1977 time period.

Under the regulation, a reconstruction has taken place if ''the fixed capital cost of the new component exceeds 50 percent of the fixed capital cost of a comparable entirely new source.'' The rule also states that ''Any final decision as to whether reconstruction has occurred must be made in accordance with the provisions of §§ 60.15 (f)(1) through (3) of this title.'' [40 CFR 51.301]. ''§§ 60.15(f)(1) through (3)'' refers to the general provisions for New Source Performance Standards (NSPS). Thus, the same policies and procedures for identifying reconstructed ''affected facilities'' under the NSPS program must also be used to identify reconstructed ''stationary sources'' for purposes of the BART requirement.

You should identify reconstructions on an emissions unit basis, rather than on a plantwide basis. That is, you need to identify only the reconstructed emission units meeting the 50 percent cost criterion. You should include reconstructed emission units in the list of emission units you identified in Step 1.

The ''in operation'' and ''in existence'' tests apply to reconstructed sources. If an emissions unit was reconstructed and began actual operation before August 7, 1962, it is not BART-eligible. Similarly, any emissions unit for which a reconstruction ''commenced'' after August 7, 1977, is not BART-eligible.

How are modifications treated under the BART provision?

The NSPS program and the major source NSR program both contain the concept of modifications. In general, the term ''modification'' refers to any physical change or change in the method of operation of an emissions unit that leads to an increase in emissions.

The BART provision in the regional haze rule contains no explicit treatment of modifications. Accordingly, guidelines are needed on how modified emissions units, previously subject to best available control technology (BACT), lowest achievable emission rate (LAER) and/or NSPS, are treated under the rule. The EPA believes that the best interpretation for purposes of the visibility provisions is that modified emissions units are still ''existing.'' The BART requirements in the CAA do not appear to provide any exemption for sources which were modified since 1977. Accordingly, if an emissions unit began operation before 1962, it is not BART-eligible if it is modified at a later date, so long as the modification is not also a ''reconstruction.'' Similarly, an emissions unit which began operation within the 1962–1977 time window, but was modified after August 7, 1977, is BART-eligible. We note, however, that if such a modification was a major modification subject to the BACT, LAER, or NSPS levels of control, the review process will take into account that this level of control is already in place and may find that the level of controls are already consistent with BART. The EPA requests comment on this interpretation for ''modifications.'' [3]

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

The result of Steps 1 and 2 will be a list of emissions units at a given plant site, including reconstructed emissions units, that are within one or more of the BART categories and that were placed into operation within the 1962–1977 time window. The third step is to determine whether the total emissions represent a current potential to emit that is greater than 250 tons per year of any single visibility impairing pollutant. In most cases, you will add the potential emissions from all emission units on the list resulting from Steps 1 and 2. In a few cases, you may need to determine whether the plant contains more than one ''stationary source'' as the regional haze rule defines that term, and as we explain further below.

What pollutants should I address?

Visibility-impairing pollutants include the following:

—Sulfur dioxide (SO_2),
—Nitrogen oxides (NO_X),
—Particulate matter. (You may use PM_{10} as the indicator for particulate matter. We do not recommend use of total suspended particulates (TSP). PM_{10} emissions include the components of $PM_{2.5}$ as a subset. There is no need to have separate 250 ton thresholds for PM_{10} and $PM_{2.5}$, because 250 tons of PM_{10} represents at most 250 tons of $PM_{2.5}$, and at most 250 tons of any individual particulate species such as elemental carbon, crustal material, etc).
—Volatile organic compounds (VOC), and
—Ammonia.

What does the term ''potential'' emissions mean?

The regional haze rule defines potential to emit as follows:

''Potential to emit'' means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

[3] Another possible interpretation would be to consider sources built before 1962 but modified during the 1962–1977 time window as a ''new'' source at the time of the modification. Under this approach, such sources would be considered to have commenced operation during the 1962–1977 time period, and thus would be BART eligible. Similarly, consistent with this interpretation, a source modified after the 1977 date would be treated as ''new'' as of the date of the modification and therefore would not be BART-eligible. The EPA believes that this approach may be much more difficult to implement, given that programs to identify ''modifications'' were not in place for much of the 1962–1977 time period.

This definition is identical to that in the PSD program (40 CFR 51.166 and 51.18). This means that a source which actually emits less than 250 tons per year of a visibility-impairing pollutant is BART-eligible if its emissions would exceed 250 tons per year when operating at its maximum physical and operational design.

Example: A source, while operating at one-fourth of its capacity, emits 75 tons per year of SO_2. If it were operating at 100 percent of its maximum capacity, the source would emit 300 tons per year. Because under the above definition such a source would have ''potential'' emissions that exceed 250 tons per year, the source (if in a listed category and built during the 1962–1977 time window) would be BART-eligible.

A source's ''potential to emit'' may take into account federally enforceable emission limits.

Example: The same source has a federally enforceable restriction limiting it to operating no more than ½ of the year. Because you can credit this under the definition of potential to emit, the source would have a potential of 150 tons per year, which is less than the 250 tons/year cutoff.

The definition of potential to emit allows only federally enforceable emission limits to be taken into account for this purpose, and does not credit emission limitations which are enforceable only by State and local agencies, but not by EPA and citizens in Federal court. As a result of some court cases in other CAA programs, EPA is undertaking a rulemaking to determine whether only federally enforceable limits should be taken into account. This rulemaking will address the Federal enforceability restriction in the regional haze definition as well as other program definitions. We expect that this rulemaking will be complete well before the time period for determining whether BART applies.

How do I identify whether a plant has more than one ''stationary source?''

The regional haze rule, in 40 CFR 51.301, defines a stationary source as a ''building, structure, facility or installation which emits or may emit any air pollutant.'' [4] The rule further defines ''building, structure or facility'' as:

All of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant-emitting activities must be considered as part of the same industrial grouping if they belong to the same Major Group (i.e., which have the same two-digit code) as described in the Standard Industrial Classification Manual, 1972 as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101–0066 and 003–005–00176–0 respectively).

In applying this definition, it is first necessary to draw the plant boundary, that is the boundary for the ''contiguous or adjacent properties.'' Next, within this plant boundary it is necessary to group those emission units that are under ''common control.'' The EPA notes that these plant boundary issues and ''common control'' issues are very similar to those already addressed in implementation of the title V operating permits program and in NSR.

For emission units within the ''contiguous or adjacent'' boundary and under common control, you then group emission units that are within the same industrial grouping (that is, associated with the same 2-digit Standard Industrial Classification (SIC) code).[5] For most plants on the BART source category list, there will only be one 2-digit SIC that applies to the entire plant. For example, all emission units associated with kraft pulp mills are within SIC code 26, and chemical process plants will generally include emission units that are all within SIC code 28. You should apply this ''2-digit SIC test'' the same way you are now applying this test in the major source NSR programs.[6]

For purposes of the regional haze rule, you group emissions from all emission units put in place within the 1962–1977 time period that are within the 2-digit SIC code, even if those emission units are in different categories on the BART category list.

Examples: A chemical plant which started operations within the 1962 to 1977 time period manufactures hydrochloric acid (within the category title ''Hydrochloric, sulfuric, and nitric acid plants'') and various organic chemicals (within the category title ''chemical process plants''), and has onsite an industrial boiler greater than 250 million BTU/hour. All of the emission units are within SIC 28 and, therefore, all the emission units are considered in determining BART eligibility of the plant. You sum the emissions over all of these emission units to see whether there are more than 250 tons per year of potential emissions.

A steel mill which started operations within the 1962 to 1977 time period includes a sintering plant, a coke oven battery, and various other emission units. All of the emission units are within SIC 33. You sum the emissions over all of these emission units to see whether there are more than 250 tons per year of potential emissions.

4. Final Step: Identify the Emissions Units and Pollutants That Constitute the BART-Eligible Source

If the emissions from the list of emissions units at a stationary source exceed a potential to emit of 250 tons per year for any visibility-impairing pollutant, then that collection of emissions units is a BART-eligible source. A BART analysis is required for each visibility-impairing pollutant emitted.

Example: A stationary source comprises the following two emissions units, with the following potential emissions:

Emissions unit A
500 tons/yr SO_2
150 tons/yr NO_X
25 tons/yr PM
Emissions unit B
100 tons/yr SO_2
75 tons/yr NO_X
10 tons/yr PM

For this example, potential emissions of SO_2 are 600 tons per year, which exceeds the 250 tons/yr threshold. Accordingly, the entire ''stationary source'' that is emissions units A and B are subject to a BART review for SO_2, NO_X, and PM, even though the potential emissions of PM and NO_X each are less than 250 tons/yr.

Example: The total potential emissions, obtained by adding the potential emissions of all emission units in listed categories at a plant site, are as follows:

200 tons/yr SO_2
150 tons/yr NO_X
25 tons/yr PM

Even though total emissions exceed 250 tons per year, no individual regulated pollutant exceeds 250 tons per year and this source is not BART-eligible.

III. How To Identify Sources ''Subject To BART''

After you have identified the BART-eligible sources, the next step is determining whether these sources are subject to a further BART analysis because they emit ''an air pollutant which may reasonably be anticipated to cause or contribute'' to any visibility

[4] **Note:** Most of these terms and definitions are the same for regional haze and the 1980 visibility regulations. For the regional haze rule we use the term ''BART-eligible source'' rather than ''existing stationary facility'' to clarify that only a limited subset of existing stationary sources are subject to BART.

[5] The EPA recognizes that we are in transition period from the use of the SIC system to a new system called the North American industry Classification System (NAICS). Our initial thinking is that BART determinations, as a one-time activity, are perhaps best handled under the SIC classifications. We request comment on whether a switch to the new system for the regional haze rule is warranted—we expect that few if any BART eligibility determinations would hinge on this distinction.

[6] **Note:** The concept of support facility used for the PSD program applies here as well. As discussed in the draft *New Source Review Workbook Manual,* October 1990, pages A.3–A.5, support facilities, that is facilities that convey, store or otherwise assist in the production of the principal product, must be grouped with primary facilities even when more than one 2-digit SIC is present.

impairment in a Federal Class I area. As we discuss in the preamble to the regional haze rule at 64 FR 35739–35740, the statutory language represents a very low triggering threshold. In implementing the regional haze rule, you should find that a BART-eligible source is ''reasonably anticipated to cause or contribute'' to regional haze if the source emits pollutants within a geographic region from which pollutants can be emitted and transported downwind to a Class I area. Where emissions from a given geographic region contribute to regional haze in a Class I area, you should consider any emissions from BART-eligible sources in that region to contribute to the regional haze problem, thereby warranting a further BART analysis for those sources.

A. How Can I Identify ''the Geographic Area'' or ''Region'' That Contributes to a Given Class I Area?

As noted in the preamble to the regional haze rule, geographic ''regions'' that can contribute to regional haze generally extend for hundreds or thousands of kilometers (64 FR 35722). Accordingly, most BART-eligible sources are located within such a geographic region. For example, we believe it would be difficult to demonstrate that a State or territory's emissions do not contribute to regional haze impairment in a Class I area within that State or territory.

The regional haze rule recognizes that there may be geographic areas (individual States or multi-State areas) within the United States, (in virtually all cases involving States that do not have Class I areas) for which the total emissions make only a trivial contribution to visibility impairment in any Class I area. In identifying any such State or area, you or a regional planning organization must conduct an air quality modeling analysis to demonstrate that the total emissions from the State or area makes only a trivial contribution to visibility impairment in Class I areas.

One approach that can be used is to determine whether a State or area contributes in a non-trivial way would be to do an analysis where you compare the visibility impairment in a Class I area with the emissions from a State or area to the visibility impairment in the Class I area in the absence of the emissions from the State or area. This approach can be referred to as a ''zero-out'' approach where you zero out the emissions from the State or area that is suspected to make a trivial contribution to visibility impairment in a Class I area. Under this approach, you would compare:

(1) the visibility impairment in each affected Class I area (for the average of the 20 percent most impaired days and the 20 percent least impaired days) when the emissions from the State or area suspected to have a trivial contribution are included in the modeling analysis, and

(2) the visibility impairment in each affected Class I area (for the average of the 20 percent most impaired days and the 20 percent least impaired days), excluding from the modeling analysis the emissions from the geographic area suspected to have a trivial impact.

The difference in visibility between these two model runs provides an indication of the impact on visibility of emissions from the State(s) in question. In addition, it may be possible in the future to conduct analyses of the geographic area that contributes to visibility impairment in a Class I area through use of a source apportionment model for PM. Source apportionment models for PM are currently under development by private consultants. Guidance for regional modeling for visibility and PM is found in a document entitled ''Guidance for Demonstrating Attainment of Air Quality Goals for $PM_{2.5}$ and Regional Haze.'' [**Note:** this document is currently in draft form, but we expect a final document before final publication of the BART guidelines]

IV. Engineering Analysis of BART Options

This section describes the process for the engineering analysis of control options for sources subject to BART.

A. What Factors Must I Address in the Engineering Analysis?

The visibility regulations define BART as follows:

Best Available Retrofit Technology (BART) means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by * * * [a BART-eligible source]. 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 non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

In the regional haze rule, we divide the BART analysis into two parts: an engineering analysis requirement in 40 CFR 51.308(e)(1)(ii)(A), and a visibility impacts analysis requirement in 40 CFR 51.308(e)(1)(ii)(B). This section of the guidelines address the requirements for the engineering analysis. Your engineering analysis identifies the best system of continuous emission reduction taking into account:

—The available retrofit control options,
—Any pollution control equipment in use at the source (which affects the availability of options and their impacts),
—The costs of compliance with control options,
—The remaining useful life of the facility (which as we will discuss below, is an integral part of the cost analysis), and
—The energy and non-air quality environmental impacts of control options.

We discuss the requirement for a visibility impacts analysis below in section V.

B. How Does a BART Engineering Analysis Compare to a BACT Review Under the PSD Program?

In this proposal, we are seeking comment on two alternative approaches for conducting a BART engineering analysis. EPA prefers the first approach. Under this first alternative, the BART analysis would be very similar to the BACT review as described in the New Source Review Workshop Manual (Draft, October 1990). Consistent with the Workshop Manual, the BART engineering analysis would be a process which provides that all available control technologies be ranked in descending order of control effectiveness. Under this option, you must first examine the most stringent alternative. That alternative is selected as the ''best'' unless you demonstrate and document that the alternative cannot be justified based upon technical considerations, costs, energy impacts, and non-air quality environmental impacts. If you eliminate the most stringent technology in this fashion, you then consider the next most stringent alternative, and so on.

The EPA also requests comment on an alternative decision-making approach that would not necessarily begin with an evaluation of the most stringent control option. Under this approach, you would have more choices in the way you structure your BART analysis. For example, you could choose to begin the BART determination process by evaluating the least stringent technically feasible control option or an intermediate control option drawn from the range of technically feasible control alternatives. Under this approach, you would then consider the additional emission reductions, costs, and other effects (if any) of successively more stringent control options. Under such an approach, you would still be required to (1) display and rank all of the options in order of control effectiveness, including the most stringent control option, and to identify the average and incremental costs of each option; (2) consider the energy and non-air quality environmental impacts of each option; and (3) provide a justification for adopting the control technology that you select as the ''best'' level of control, including an explanation as to why you rejected other more stringent control technologies. While both approaches require essentially the same parameters and analyses, the EPA prefers the first approach described above, because we believe it may be more straightforward to implement than the alternative and would tend to give more thorough consideration to stringent control alternatives.

Although very similar in process, BART reviews differ in several respects from the BACT review process described in the NSR Draft Manual. First, because all BART reviews apply to existing sources, the available controls and the impacts of those controls may differ. Second, the CAA requires you to take slightly different factors into account in determining BART and BACT. In a BACT analysis, the permitting authority must consider the ''energy, environmental and economic impacts and other costs'' associated with a control technology in making its determination. In a BART analysis, on the other hand, the State must take into account the ''cost of compliance, the remaining useful life of the source, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, and the degree of improvement in visibility from the use of such technology'' in making its BART determination. Because of the differences in terminology, the BACT review process tends to encompass a broader range of factors. For example, the term ''environmental impacts'' in the BACT definition is more broad than the term ''nonair quality environmental impacts'' used in the BART definition. Accordingly, there is no requirement in the BART engineering analysis to evaluate adverse air quality impacts of control alternatives such as the relative impacts on hazardous air pollutants, although you may wish to do so. Finally, for the BART analysis, there is no minimum level of control required, while any BACT emission limitation must be at least as stringent as any NSPS that applies to the source.

C. Which Pollutants Must I Address in the Engineering Review?

Once you determine that a source is subject to BART, then a BART review is required for each visibility-impairing pollutant emitted. In a BART review, for each affected emission unit, you must establish BART for each pollutant that can impair visibility. Consequently, the BART determination must address air pollution control measures for each emissions unit or pollutant emitting activity subject to review.

Example: Plantwide emissions from emission units within the listed categories that began operation within the ''time window'' for BART [7] are 300 tons per year of NO_X, 200 tons per year of SO_2, and 150 tons of primary particulate. Emissions unit A emits 200 tons per year of NO_X, 100 tons per year of SO_2, and 100 tons per year of primary particulate. Other emission units, units B through H, which began operating in 1966, contribute lesser amounts of each pollutant. For this example, a BART review is required for NO_X, SO_2, and primary particulate, and control options must be analyzed for units B through H as well as unit A.

D. What Are the Five Basic Steps of a Case-by-Case BART Engineering Analysis?

The five steps are:

Step 1—Identify all [8] available retrofit control technologies,
Step 2—Eliminate Technically Infeasible Options,
Step 3—Rank Remaining Control Technologies By Control Effectiveness,
Step 4—Evaluate Impacts and Document the Results, and
Step 5—Select ''Best System of Continuous Emission Reduction.''

1. Step 1: How Do I Identify All Available Retrofit Emission Control Techniques?

Available retrofit control options are those air pollution control technologies with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies can include a wide variety of available methods, systems, and techniques for control of the affected pollutant. Available air pollution control technologies can include technologies employed outside of the United States that have been successfully demonstrated in practice on full scale operations, particularly those that have been demonstrated as retrofits to existing sources. Technologies required as BACT or LAER are available for BART purposes and must be included as control alternatives. The control alternatives should include not only existing controls for the source category in question, but also take into account technology transfer of controls that have been applied to similar source categories and gas streams. Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered as available; we do not expect the source owner to purchase or construct a process or control device that has not already been demonstrated in practice.

Where a NSPS exists for a source category (which is the case for most of the categories affected by BART), you should include a level of control equivalent to the NSPS as one of the control options.[9] The NSPS standards are codified in 40 CFR part 60. We note that there are situations where NSPS standards do not require the most stringent level of available control for all sources within a category. For example, post-combustion NO_X controls (the most stringent controls for stationary gas turbines) are not required under subpart GG of the NSPS for Stationary Gas Turbines. However, such controls must still be considered available technologies for the BART selection process.

Potentially applicable retrofit control alternatives can be categorized in three ways.

- Pollution prevention: use of inherently lower-emitting processes/practices, including the use of materials and production processes and work practices that prevent emissions and result in lower ''production-specific'' emissions,
- Use of, (and where already in place, improvement in the performance of) add-on controls, such as scrubbers,

[7] That is, emission uunits that were in existence on August 7, 1977 and which began actual operation on or after August 7, 1962.

[8] 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.

[9] In EPA's 1980 BART guidelines for reasonably attributable visibility impairment, we concluded that NSPS standards generally, at that time, represented the best level sources could install as BART, and we required no further demonstration if a NSPS level was selected. In the 20 year period since this guidance was developed, there have been advances in SO_2 control technologies, confirmed by a number of recent retrofits at Western power plants. Accordingly, EPA no longer concludes that the NSPS level of controls automatically represents ''the best these sources can install.'' While it is possible that a detailed analysis of the BART factors could result in the selection of a NSPS level of control, we believe that you should only reach this conclusion based upon an analysis of the full range of control options.

fabric filters, thermal oxidizers and other devices that control and reduce emissions after they are produced, and

• Combinations of inherently lower-emitting processes and add-on controls. Example: for a gas-fired turbine, a combination of combustion controls (an inherently lower-emitting process) and post-combustion controls such as selective catalytic reduction (add-on) may be available to reduce NO_X emissions.

For the engineering analysis, you should consider potentially applicable control techniques from all three categories. You should consider lower-polluting processes based on demonstrations from facilities manufacturing identical or similar products from identical or similar raw materials or fuels. Add-on controls, on the other hand, should be considered based on the physical and chemical characteristics of the pollutant-bearing emission stream. Thus, candidate add-on controls may have been applied to a broad range of emission unit types that are similar, insofar as emissions characteristics, to the emissions unit undergoing BART review.

In the course of the BART engineering analysis, one or more of the available control options may be eliminated from consideration because they are demonstrated to be technically infeasible or to have unacceptable energy, cost, or non-air quality environmental impacts on a case-by-case (or site-specific) basis. However, at the outset, you should initially identify all control options with potential application to the emissions unit under review.

We do not consider BART as a requirement to redesign the source when considering available control alternatives. For example, where the source subject to BART is a coal-fired electric generator, we do not require the BART analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting on a per unit basis.

In some cases, retrofit design changes may be available for making a given production process or emissions unit inherently less polluting.[10] (Example: To allow for use of natural gas rather than oil for startup). In such cases, the ability of design considerations to make the process inherently less polluting must be considered as a control alternative for the source.

Combinations of inherently lower-polluting processes/practices (or a process made to be inherently less polluting) and add-on controls could possibly yield more effective means of emissions control than either approach alone. Therefore, the option to use an inherently lower-polluting process does not, in and of itself, mean that no additional add-on controls need to be included in the BART analysis. These combinations should be identified in Step 1 for evaluation in subsequent steps.

For emission units subject to a BART engineering review, there will often be control measures or devices already in place. For such emission units, it is important to include control options that involve improvements to existing controls, and not to limit the control options only to those measures that involve a complete replacement of control devices.

Example: For a power plant with an existing wet scrubber, the current control efficiency is 66 percent. Part of the reason for the relatively low control efficiency is that 22 percent of the gas stream bypasses the scrubber. An engineering review identifies options for improving the performance of the wet scrubber by redesigning the internal components of the scrubber and by eliminating or reducing the percentage of the gas stream that bypasses the scrubber. Four control options are identified: (1) 78 percent control based upon improved scrubber performance while maintaining the 22 percent bypass, (2) 83 percent control based upon improved scrubber performance while reducing the bypass to 15 percent, (3) 93 percent control based upon improving the scrubber performance while eliminating the bypass entirely, (this option results in a ''wet stack'' operation in which the gas leaving the stack is saturated with water) and (4) 93 percent as in option 3, with the addition of an indirect reheat system to reheat the stack gas above the saturation temperature. You must consider each of these four options in a BART analysis for this source.

You are expected to identify all demonstrated and potentially applicable retrofit control technology alternatives. Examples of general information sources to consider include:

• The EPA's Clean Air Technology Center, which includes the RACT/BACT/LAER Clearinghouse (RBLC);
• State and Local Best Available Control Technology Guidelines—many agencies have online information—for example South Coast Air Quality Management District, Bay Area Air Quality Management District, and Texas Natural Resources Conservation Commission;
• Control technology vendors;
• Federal/State/Local NSR permits and associated inspection/performance test reports;
• Environmental consultants;
• Technical journals, reports and newsletters, air pollution control seminars; and
• EPA's NSR bulletin board—http://www.epa.gov/ttn/nsr;
• Department of Energy's Clean Coal Program—technical reports;
• NO_X Control Technology ''Cost Tool''—Clean Air Markets Division web page—http://www.epa.gov/acidrain/nox/noxtech.htm;
• Performance of selective catalytic reduction on coal-fired steam generating units—final report. OAR/ARD, June 1997 (also available at http:www.epa.gov/acidrain/nox/noxtech.htm);
• Cost estimates for selected applications of NO_X control technologies on stationary combustion boilers. OAR/ARD June 1997. (Docket for NO_X SIP call, A–96–56, II–A–03);
• Investigation of performance and cost of NO_X controls as applied to group 2 boilers. OAR/ARD, August 1996. (Docket for Phase II NO_X rule, A–95–28, IV–A–4);
• Controlling SO_2 Emissions: A Review of Technologies. EPA–600/R–00–093, USEPA/ORD/NRMRL, October 2000.
• OAQPS Control Cost Manual.

You should compile appropriate information from all available information sources, and you should ensure that the resulting list of control alternatives is complete and comprehensive.

2. Step 2: How Do I Determine Whether the Options Identified in Step 1 Are Technically Feasible?

In Step two, you evaluate the technical feasibility of the control options you identified in Step one. You should clearly document a demonstration of technical infeasibility and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. You may then eliminate such technically infeasible control options from further consideration in the BART analysis.

In general, what do we mean by technical feasibility?

Control technologies are technically feasible if either (1) they have been installed and operated successfully for the type of source under review, or (2) the technology could be applied to the source under review. Two key concepts are important in determining whether a technology could be applied: ''availability'' and ''applicability.'' As explained in more detail below, a technology is considered ''available'' if

[10] Because BART applies to existing sources, we recognize that there will probably be far fewer opportunities to consider inherently lower-emitting processes than for NSR.

the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is ''applicable'' if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.

What do we mean by ''available'' technology?

The typical stages for bringing a control technology concept to reality as a commercial product are:

- Concept stage;
- Research and patenting;
- Bench scale or laboratory testing;
- Pilot scale testing;
- Licensing and commercial demonstration; and
- Commercial sales.

A control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development. Similarly, we do not expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, you would not consider technologies in the pilot scale testing stages of development as ''available'' for purposes of BART review.

Commercial availability by itself, however, is not necessarily a sufficient basis for concluding a technology to be applicable and therefore technically feasible. Technical feasibility, as determined in Step 2, also means a control option may reasonably be deployed on or ''applicable'' to the source type under consideration.

Because a new technology may become available at various points in time during the BART analysis process, we believe that guidelines are needed on when a technology must be considered. For example, a technology may become available during the public comment period on the State's rule development process. Likewise, it is possible that new technologies may become available after the close of the State's public comment period and before submittal of the SIP to EPA, or during EPA's review process on the SIP submittal. In order to provide certainty in the process, we propose that all technologies be considered if available before the close of the State's public comment period. You need not consider technologies that become available after this date. As part of your analysis, you should consider any technologies brought to your attention in public comments. If you disagree with public comments asserting that the technology is available, you should provide an explanation for the public record as to the basis for your conclusion.

What do we mean by ''applicable'' technology?

You need to exercise technical judgment in determining whether a control alternative is applicable to the source type under consideration. In general, a commercially available control option will be presumed applicable if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type. Absent a showing of this type, you evaluate technical feasibility by examining the physical and chemical characteristics of the pollutant-bearing gas stream, and comparing them to the gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on a new or existing source with similar gas stream characteristics is generally a sufficient basis for concluding the technology is technically feasible barring a demonstration to the contrary as described below.

What type of demonstration is required if I conclude that an option is not technically feasible?

Where you assert that a control option identified in Step 1 is technically infeasible, you should make a factual demonstration that the option is commercially unavailable, or that unusual circumstances preclude its application to a particular emission unit. Generally, such a demonstration involves an evaluation of the characteristics of the pollutant-bearing gas stream and the capabilities of the technology. Alternatively, a demonstration of technical infeasibility may involve a showing that there are unresolvable technical difficulties with applying the control to the source (e.g., size of the unit, location of the proposed site, or operating problems related to specific circumstances of the source). Where the resolution of technical difficulties is a matter of cost, you should consider the technology to be technically feasible. The cost of a control alternative is considered later in the process.

The determination of technical feasibility is sometimes influenced by recent air quality permits. In some cases, an air quality permit may require a certain level of control, but the level of control in a permit is not expected to be achieved in practice (e.g., a source has received a permit but the project was canceled, or every operating source at that permitted level has been physically unable to achieve compliance with the limit). Where this is the case, you should provide supporting documentation showing why such limits are not technically feasible, and, therefore, why the level of control (but not necessarily the technology) may be eliminated from further consideration. However, if there is a permit requiring the application of a certain technology or emission limit to be achieved for such technology (especially as a retrofit for an existing emission unit), this usually is sufficient justification for you to assume the technical feasibility of that technology or emission limit.

Physical modifications needed to resolve technical obstacles do not, in and of themselves, provide a justification for eliminating the control technique on the basis of technical infeasibility. However, you may consider the cost of such modifications in estimating costs. This, in turn, may form the basis for eliminating a control technology (see later discussion).

Vendor guarantees may provide an indication of commercial availability and the technical feasibility of a control technique and could contribute to a determination of technical feasibility or technical infeasibility, depending on circumstances. However, we do not consider a vendor guarantee alone to be sufficient justification that a control option will work. Conversely, lack of a vendor guarantee by itself does not present sufficient justification that a control option or an emissions limit is technically infeasible. Generally, you should make decisions about technical feasibility based on chemical, and engineering analyses (as discussed above), in conjunction with information about vendor guarantees.

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 EPA's intent to encourage evaluation of unnecessarily large numbers of control alternatives for every emissions unit. Consequently, you should use judgment in deciding on those alternatives for which you will conduct the detailed impacts analysis (Step 4 below). 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. You should narrow the scope of the BART analysis in this way, only if there is a negligible difference in emissions and energy and non-air quality environmental impacts between control alternatives.

3. Step 3: How Do I Develop a Ranking of the Technically Feasible Alternatives?

Step 3 involves ranking all the technically feasible control alternatives identified in Step 2. For the pollutant and emissions unit under review, you rank the control alternatives from the most to the least effective in terms of emission reduction potential.

Two key issues that must be addressed in this process include:

(1) Making sure that you express the degree of control using a metric that ensures an ''apples to apples'' comparison of emissions performance levels among options, and

(2) Giving appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels.

In some instances, a control technology may reduce more than one visibility impairing pollutant. We request comment on whether and how the BART guidelines should address the process for ranking such control technologies against control technologies which reduce emissions of only one pollutant.

What are the appropriate metrics for comparison?

This issue is especially important when you compare inherently lower-polluting processes to one another or to add-on controls. In such cases, it is generally most effective to express emissions performance as an average steady state emissions level per unit of product produced or processed.

Examples of common metrics:

- Pounds of SO_2 emissions per million Btu heat input, and
- Pounds of NO_X emissions per ton of cement produced.

How do I evaluate control techniques with a wide range of emission performance levels?

Many control techniques, including both add-on controls and inherently lower polluting processes, can perform at a wide range of levels. Scrubbers and high and low efficiency electrostatic precipitators (ESPs) are two of the many examples of such control techniques that can perform at a wide range of levels. It is not our intent to require analysis of each possible level of efficiency for a control technique, as such an analysis would result in a large number of options. It is important, however, that in analyzing the technology you take into account the most stringent emission control level that the technology is capable of achieving. You should use the most recent regulatory decisions and performance data (e.g., manufacturer's data, engineering estimates and the experience of other sources) to identify an emissions performance level or levels to evaluate.

In assessing the capability of the control alternative, latitude exists to consider any special circumstances pertinent to the specific source under review, or regarding the prior application of the control alternative. However, you must document 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.

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

Finally, we note that for retrofitting existing sources in addressing BART, you should consider ways to improve the performance of existing control devices, particularly when a control device is not achieving the level of control that other similar sources are achieving in practice with the same device.

How do I rank the control options?

After determining the emissions performance levels (using appropriate metrics of comparison) for each control technology option identified in Step 2, you establish a list that identifies the most stringent control technology option. Each other control option is then placed after this alternative in a ranking according to its respective emissions performance level, ranked from lowest emissions to highest emissions (most effective to least stringent effective emissions control alternative). You should do this for each pollutant and for each emissions unit (or grouping of similar units) subject to a BART analysis.

4. Step 4: For a BART Engineering Analysis, What Impacts Must I Calculate and Report? What Methods Does EPA Recommend for the Impacts Analysis?

After you identify and rank the available and technically feasible control technology options, you must then conduct three types of impacts analyses when you make a BART determination:

Impact analysis part 1: Costs of compliance, (taking into account the remaining useful life of the facility)

Impact analysis part 2: Energy impacts, and

Impact analysis part 3: Non-air quality environmental impacts.

In this section, we describe how to conduct each of these three analyses. You are responsible for presenting an evaluation of each impact along with appropriate supporting information. You should discuss and, where possible, quantify both beneficial and adverse impacts. In general, the analysis should focus on the direct impact of the control alternative.

a. *Impact analysis part 1: How do I estimate the costs of control?* To conduct a cost analysis, you:

—Identify the emissions units being controlled,

—Identify design parameters for emission controls, and

—Develop cost estimates based upon those design parameters.

It is important to identify clearly the emission units being controlled, that is, to specify a well-defined area or process segment within the plant. In some cases, multiple emission units can be controlled jointly. However, in other cases it may be appropriate in the cost analysis to consider whether multiple units will be required to install separate and/or different control devices. The engineering analysis should provide a clear summary list of equipment and the associated control costs. Inadequate documentation of the equipment whose emissions are being controlled is a potential cause for confusion in comparison of costs of the same controls applied to similar sources.

You then specify the control system design parameters. Potential sources of these design parameters include equipment vendors, background information documents used to support NSPS development, control technique guidelines documents, cost manuals developed by EPA, control data in trade publications, and engineering and performance test data. The following are a few examples of design parameters for two example control measures:

Control device	Examples of design parameters
Wet Scrubbers	Type of sorbent used (lime, limestone, etc.) Gas pressure drop Liquid/gas ratio.

Control device	Examples of design parameters
Selective Catalytic Reduction.	Ammonia to NO_X molar ratio Pressure drop Catalyst life.

The value selected for the design parameter should ensure that the control option will achieve the level of emission control being evaluated. You should include in your analysis, documentation of your assumptions regarding design parameters. Examples of supporting references would include the Office of Air Quality Planning and Standards (OAQPS) *Control Cost Manual* (see below) and background information documents used for NSPS and hazardous pollutant emission standards. If the design parameters you specified differ from typical designs, you should document the difference by supplying performance test data for the control technology in question applied to the same source or a similar source.

Once the control technology alternatives and achievable emissions performance levels have been identified, you then develop estimates of capital and annual costs. The 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 Control Cost Manual,* Fifth Edition, February 1996, EPA 453/B–96–001).[11] In order to maintain and improve consistency, we recommend that you estimate control equipment costs based on the EPA/OAQPS *Control Cost Manual,* where possible.[12] The *Control Cost Manual* addresses most control technologies in sufficient detail for a BART analysis. While the types of site-specific analyses contained in the *Control Cost Manual* are less precise than those based upon a detailed engineering design, normally the estimates provide results that are plus or minus 30 percent, which is generally sufficient for the BART review. The cost analysis should take into account site-specific conditions that are out of the ordinary (e.g., use of a more expensive fuel or additional waste disposal costs) that may affect the cost of a particular BART technology option.

b. *How do I take into account a project's ''remaining useful life'' in calculating control costs?* You treat the requirement to consider the source's ''remaining useful life'' of the source for BART determinations as one element of the overall cost analysis. The ''remaining useful life'' of a source, if it represents a relatively short time period, may affect the annualized costs of retrofit controls. For example, the methods for calculating annualized costs in EPA's *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.

For purposes of these guidelines, the remaining useful life is the difference between:

(1) January 1 of the year you are conducting the BART analysis (but not later than January 1, 2008);[13] and

(2) The date the facility stops operations. This date must be assured by a federally-enforceable restriction preventing further operation. A projected closure date, without such a federally-enforceable restriction, is not sufficient. (The EPA recognizes that there may be situations where a source operator intends to shut down a source by a given date, but wishes to retain the flexibility to continue operating beyond that date in the event, for example, that market conditions change.) We request comment on how such flexibility could be provided in this regard while maintaining consistency with the statutory requirement to install BART within 5 years. For example, one option that we request comment on is allowing a source to choose between:

(1) Accepting a federally enforceable condition requiring the source to shut down by a given date, or

(2) Installing the level of controls that would have been considered BART if the BART analysis had not assumed a reduced remaining useful life if the source is in operation 5 years after the date EPA approves the relevant SIP. The source would not be allowed to operate after the 5-year mark without such controls.

c. *What do we mean by cost effectiveness?* Cost effectiveness, in general, is a criterion used to assess the potential for achieving an objective at least cost. For purposes of air pollutant analysis, ''effectiveness'' is measured in terms of tons of pollutant emissions removed, and ''cost'' is measured in terms of annualized control costs. We recommend two types of cost-effectiveness calculations—average cost effectiveness, and incremental cost-effectiveness.

In the cost analysis, you should take care to not focus on incomplete results or partial calculations. For example, large capital costs for a control option alone would not preclude selection of a control measure if large emissions reductions are projected. In such a case, low or reasonable cost effectiveness numbers may validate the option as an appropriate BART alternative irrespective of the large capital costs. Similarly, projects with relatively low capital costs may not be cost effective if there are few emissions reduced.

d. *How do I calculate average cost effectiveness?* Average cost effectiveness means the total annualized costs of control divided by annual emissions reductions (the difference between baseline annual emissions and the estimate of emissions after controls), using the following formula:

$$\begin{array}{c}\text{Average cost effectiveness}\\ \text{(dollars per ton removed)}\end{array} = \frac{\text{Control option annualized cost}^{14}}{\text{Baseline annual emissions} - \text{Annual emissions with Control option}}$$

[11] The *Control Cost Manual* is updated periodically. While this citation refers to the latest version at the time this guidance was written, you should use the version that is current as of when you conduct your impact analysis. This document is available at the following Web site: *http://www.epa.gov/ttn/catc/dir1/chpt2acr.pdf.*

[12] You should include documentation for any additional information you used for the cost calculations, including any information supplied by vendors that affects your assumptions regarding purchased equipment costs, equipment life, replacement of major components, and any other element of the calculation that differs from the *Control Cost Manual.*

[13] The reason for the year 2008 is that the year 2008 is the latest year for which SIPs are due to address the BART requirement.

[14] Whenever you calculate or report annual costs, you should indicate the year for which the costs are estimated. For example, if you use the year 2000 as the basis for cost comparisons, you would report that an annualized cost of $20 million would be: $20 million (year 2000 dollars).

Because you calculate costs in (annualized) dollars per year ($/yr) and because you calculate emissions rates in tons per year (tons/yr), the result is an average cost-effectiveness number in (annualized) dollars per ton ($/ton) of pollutant removed.

e. *How do I calculate baseline emissions?* 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. For purposes of estimating actual emissions, these guidelines take a similar approach to the current definition of actual emissions in NSR programs. That is, the baseline emissions are the average annual emissions from the two most recent years, unless you demonstrate that another period is more representative of normal source operations.[15]

When you project that future operating parameters (e.g., limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) will differ from past practice, and if this projection has a deciding effect in the BART determination, then you must make these parameters or assumptions into enforceable limitations. In the absence of enforceable limitations, you calculate baseline emissions based upon continuation of past practice.

Examples: The baseline emissions calculation for an emergency standby generator may consider the fact that the source owner would not operate more than past practice of 2 weeks a year. On the other hand, baseline emissions associated with a base-loaded turbine should be based on its past practice which would indicate a large number of hours of operation. This produces a significantly higher level of baseline emissions than in the case of the emergency/standby unit and results in more cost-effective controls. As a consequence of the dissimilar baseline emissions, BART for the two cases could be very different.

f. *How do I calculate incremental cost effectiveness?* In addition to the average cost effectiveness of a control option, you should also calculate incremental cost effectiveness. You should consider the incremental cost effectiveness in combination with the total cost effectiveness in order to justify elimination of a control option. The incremental cost effectiveness calculation compares the costs and emissions performance level of a control option to those of the next most stringent option, as shown in the following formula:

Incremental Cost Effectiveness (dollars per incremental ton removed) = (Total annualized costs of control option) − (Total annualized costs of next control option) ÷ (Next control option annual emissions) − (Control option annual emissions)

Example 1: Assume that Option F on Figure 2 has total annualized costs of $1 million to reduce 2000 tons of a pollutant, and that Option D on Figure 2 has total annualized costs of $500,000 to reduce 1000 tons of the same pollutant. The incremental cost effectiveness of Option F relative to Option D is ($1 million − $500,000) divided by (2000 tons − 1000 tons), or $500,000 divided by 1000 tons, which is $500/ton.

Example 2: Assume that two control options exist: Option 1 and Option 2. Option 1 achieves a 100,000 ton/yr reduction at an annual cost of $19 million. Option 2 achieves a 98,000 tons/yr reduction at an annual cost of $15 million. The incremental cost effectiveness of Option 1 relative to Option 2 is ($19 million − $15 million) divided by (100,000 tons − 98,000 tons). The adoption of Option 1 instead of Option 2 results in an incremental emission reduction of 2,000 tons per year at an additional cost of $4,000,000 per year. The incremental cost of Option 1, then, is $2000 per ton − 10 times the average cost of $190 per ton. While $2000 per ton may still be deemed reasonable, it is useful to consider both the average and incremental cost in making an overall cost-effectiveness finding. Of course, there may be other differences between these options, such as, energy or water use, or non-air environmental effects, which also deserve consideration in selecting a BART technology.

You should exercise care in deriving incremental costs of candidate control options. Incremental cost-effectiveness comparisons should focus on annualized cost and emission reduction differences between ''dominant'' alternatives. To identify dominant alternatives, you generate a graphical plot of total annualized costs for total emissions reductions for all control alternatives identified in the BART analysis, and by identifying a ''least-cost envelope'' as shown in Figure 2.

Example: Eight technically feasible control options for analysis are listed in the BART ranking. These are represented as A through H in Figure 2. The dominant set of control options, B, D, F, G, and H, represent the least-cost envelope, as we depict by the cost curve connecting them. Points A, C and E are inferior options, and you should not use them in calculating incremental cost effectiveness. Points A, C and E represent inferior controls because B will buy more emissions reductions for less money than A; and similarly, D and F will buy more reductions for less money than C and E, respectively.

In calculating incremental costs, you:

(1) Rank the control options in ascending order of annualized total costs,

(2) Develop a graph of the most reasonable smooth curve of the control options, as shown in Figure 2, and

(3) Calculate the incremental cost effectiveness for each dominant option, which is the difference in total annual costs between that option and the next most stringent option, divided by the difference in emissions reductions between those two options. For example, using Figure 2, you would calculate incremental cost effectiveness for the difference between options B and D, options D and F, options F and G, and options G and H.

[15] This is the approach in the current NSR regulations. It is possible that this definition of baseline period may change based upon a current effort to amend the NSR regulations. We propose that these guidelines should be amended to be consistent with the approach taken in that separate rulemaking.

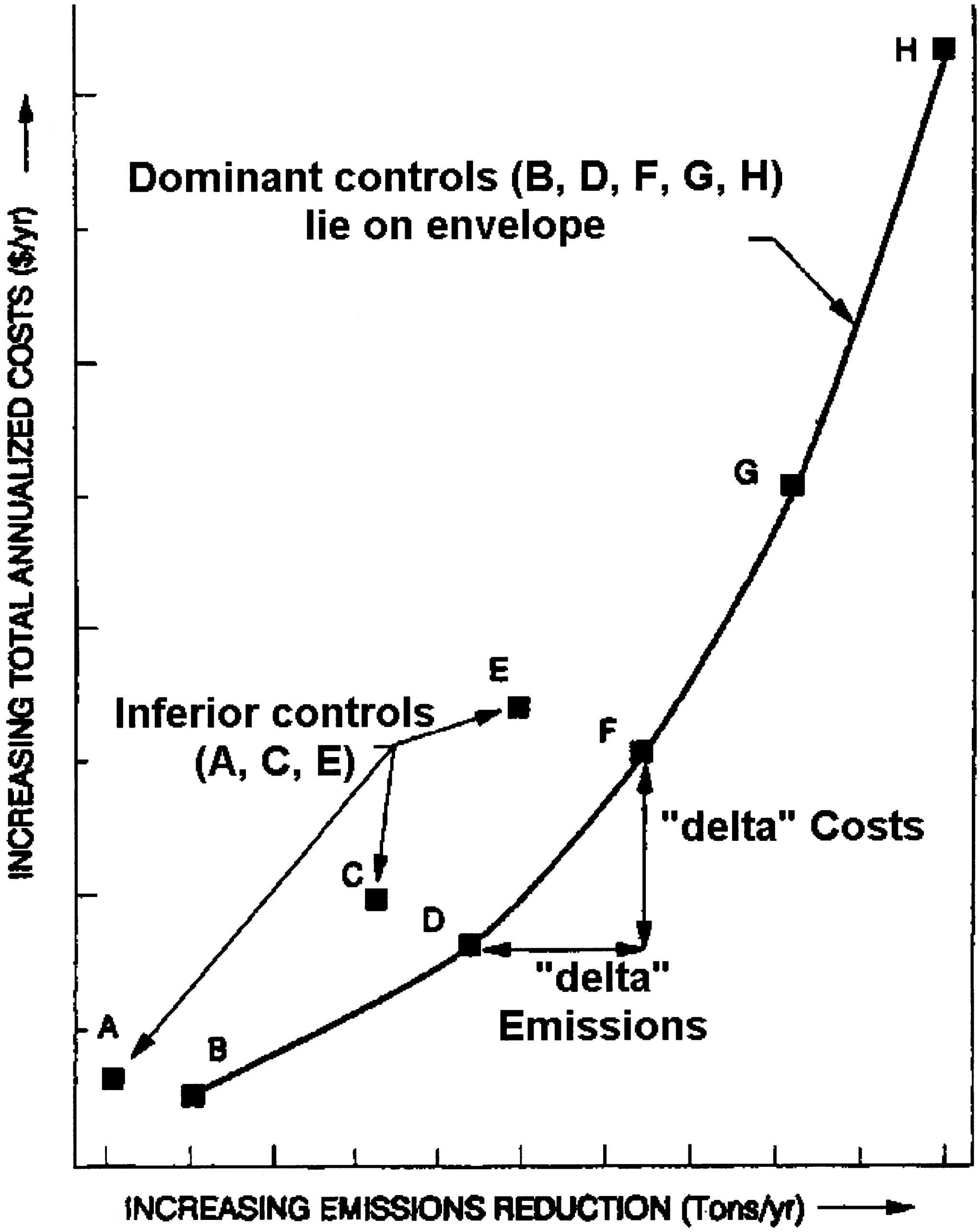

Figure 2. Least-cost Envelope.

A comparison of incremental costs can also be useful in evaluating the viability of a specific control option over a range of efficiencies. For example, depending on the capital and operational cost of a control device, total and incremental cost may vary significantly (either increasing or decreasing) over the operational range of a control device.

In addition, when you evaluate the average or incremental cost effectiveness of a control alternative, you should make reasonable and supportable assumptions regarding control efficiencies. An unrealistically low assessment of the emission reduction potential of a certain technology could result in inflated cost-effectiveness figures.

g. *What other information should I provide in the cost impacts analysis?* You should provide documentation of any unusual circumstances that exist for the source that would lead to cost-effectiveness estimates that would exceed that for recent retrofits. This is especially important in cases where recent retrofits have cost-effectiveness values that are within a reasonable range, but your analysis concludes that costs for the source being analyzed are not reasonable.

Example: In an arid region, large amounts of water are needed for a scrubbing system. Acquiring water from a distant location could greatly increase the cost effectiveness of wet scrubbing as a control option.

h. *Impact analysis part 2: How should I analyze and report energy impacts?* You should examine the energy requirements of the control technology and determine whether the use of that technology results in any significant or unusual energy penalties or benefits. A source owner may, for example, benefit from the combustion of a concentrated gas stream rich in volatile organic compounds; on the other hand, more often extra fuel or electricity is required to power a control device or incinerate a dilute gas stream. If such benefits or penalties exist, they should be quantified and included in the cost analysis. Because energy penalties or benefits can usually be quantified in terms of additional cost or income to the source, the energy impacts analysis can, in most cases, simply be factored into the cost impacts analysis. However, certain types of control technologies have inherent energy penalties associated with their use. While you should quantify these penalties, so long as they are within the normal range for the technology in question, you should not, in general, consider such penalties to be an adequate justification for eliminating that technology from consideration.

Your energy impact analysis should consider only direct energy consumption and not indirect energy impacts. For example, you could estimate the direct energy impacts of the control alternative in units of energy consumption at the source (e.g., BTU, kWh, barrels of oil, tons of coal). The energy requirements of the control options should be shown in terms of total (and in certain cases, also incremental) energy costs per ton of pollutant removed. You can then convert these units into dollar costs and, where appropriate, factor these costs into the control cost analysis.

You generally do not consider indirect energy impacts (such as energy to produce raw materials for construction of control equipment). However, if you determine, either independently or based on a showing by the source owner, that the indirect energy impact is unusual or significant and that the impact can be well quantified, you may consider the indirect impact.

The energy impact analysis may also address concerns over the use of locally scarce fuels. The designation of a scarce fuel may vary from region to region. However, in general, a scarce fuel is one which is in short supply locally and can be better used for alternative purposes, or one which may not be reasonably available to the source either at the present time or in the near future.

Finally, the energy impacts analysis may consider whether there are relative differences between alternatives regarding the use of locally or regionally available coal, and whether a given alternative would result in significant economic disruption or unemployment. For example, where two options are equally cost effective and achieve equivalent or similar emissions reductions, one option may be preferred if the other alternative results in significant disruption or unemployment.

i. *Impact analysis part 3: How do I analyze ''non-air quality environmental impacts?''* In the non-air quality related environmental impacts portion of the BART analysis, you address environmental impacts other than air quality due to emissions of the pollutant in question. Such environmental impacts include solid or hazardous waste generation and discharges of polluted water from a control device.

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

The procedure for conducting an analysis of non-air quality environmental impacts should be made based on a consideration of site-specific circumstances. It is not necessary to perform this analysis of environmental impacts for the entire list of technologies you ranked in Step 3, if you propose to adopt the most stringent alternative. In that case, the analysis need only address those control alternatives with any significant or unusual environmental impacts that have the potential to affect the selection or elimination of a control alternative. Thus, any important relative environmental impacts (both positive and negative) of alternatives can be compared with each other.

In general, the analysis of impacts starts with the identification and quantification of the solid, liquid, and gaseous discharges from the control device or devices under review. Initially, you should perform a qualitative or semi-quantitative screening to narrow the analysis to discharges with potential for causing adverse environmental effects. Next, you should assess the mass and composition of any such discharges and quantify them to the extent possible, based on readily-available information. You should also assemble pertinent information about the public or environmental consequences of releasing these materials.

j. *What are examples of non-air quality environmental impacts?* The following are examples of how to conduct non-air quality environmental impacts:

- *Water Impact*

You should identify the relative quantities of water used and water pollutants produced and discharged as a result of the use of each alternative emission control system relative to the most stringent alternative. Where possible, you should assess the effect on ground water and such local surface water quality parameters as ph, turbidity, dissolved oxygen, salinity, toxic chemical levels, temperature, and any other important considerations. The analysis should consider whether applicable water quality standards will be met and the availability and effectiveness of various techniques to reduce potential adverse effects.

- *Solid Waste Disposal Impact*

You should compare the quality and quantity of solid waste (e.g., sludges, solids) that must be stored and disposed of or recycled as a result of the application of each alternative emission control system with the quality and quantity of wastes created with the most stringent emission control system. You should consider the composition and various other characteristics of the solid waste (such as permeability, water retention, rewatering of dried material, compression strength, leachability of dissolved ions, bulk density, ability to support vegetation growth and hazardous characteristics) which are significant with regard to potential surface water pollution or transport into and contamination of subsurface waters or aquifers.

- *Irreversible or Irretrievable Commitment of Resources*

You may consider the extent to which the alternative emission control systems may involve a trade-off between short-term environmental gains at the expense of long-term environmental losses and the extent to which the alternative systems may result in irreversible or irretrievable commitment of resources (for example, use of scarce water resources).

- *Other Adverse Environmental Impacts*

You may consider significant differences in noise levels, radiant heat, or dissipated static electrical energy. Other examples of non-air quality environmental impacts would include hazardous waste discharges such as spent catalysts or contaminated carbon. Generally, these types of environmental concerns become important when the plant is located in an area that is sensitive to environmental degradation and when the incremental emissions reductions potential of the most stringent control option is only marginally greater than the next most-effective option.

- *Benefits to the Environment*

It is important to consider relative differences between options regarding their *beneficial impacts* to non-air quality-related environmental media. For example, you may consider whether a given control option results in less deposition of pollutants to nearby sensitive water bodies.

5. Step 5: How Do I Select the ''Best'' Alternative, Using the Results of Steps 1 Through 4?

a. *Summary of the Impacts Analysis.* From the alternatives you ranked in Step 3, you should develop a chart (or charts) displaying for each of the ranked alternatives:

- Expected emission rate (tons per year, pounds per hour);
- Emissions performance level (e.g., percent pollutant removed, emissions per unit product, lb/MMbtu, ppm);
- Expected emissions reductions (tons per year);
- Costs of compliance—total annualized costs ($), cost effectiveness ($/ton), and incremental cost effectiveness ($/ton);
- Energy impacts (indicate any significant energy benefits or disadvantages);
- Non-air quality environmental impacts (includes any significant or unusual other media impacts, e.g., water or solid waste), both positive and negative.

b. *Selecting a ''best'' alternative.* As discussed above, we are seeking comment on two alternative approaches for evaluating control options for BART. The first involves a sequential process for conducting the impacts analysis that begins with a complete evaluation of the most stringent control option. Under this approach, you determine that the most stringent alternative in the ranking does not impose unreasonable costs of compliance, taking into account both average and incremental costs, then the analysis begins with a presumption that this level is selected. You then proceed to considering whether energy and non-air quality environmental impacts would justify selection of an alternative control option. If there are no outstanding issues regarding energy and non-air quality environmental impacts, the analysis is ended and the most stringent alternative is identified as the ''best system of continuous emission reduction.''

If you determine that the most stringent alternative is unacceptable due to such impacts, you need to document the rationale for this finding for the public record. Then, the next most-effective alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until you identify a technology which does not pose unacceptable costs of compliance, energy and/or non-air quality environmental impacts.

The EPA also requests comment on an alternative decision-making approach that would not begin with an evaluation of the most stringent control option. For example, you 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, you would then consider the additional emissions reductions, costs, and other effects (if any) of successively more stringent control options. Under such an approach, you would still be required to (1) display and rank all of the options in order of control effectiveness and to identify the average and incremental costs of each option; (2) consider the energy and non-air quality environmental impacts of each option; and (3) provide a justification for adopting the technology that you select as the ''best'' level of control, including an explanation as to why you rejected other more stringent control technologies.

Because of EPA's experience in evaluating SO_2 control options for utility boilers, the Agency is proposing to establish a presumption regarding the level of SO_2 control that is generally achievable for such sources. Based on the cost models in the *Controlling SO_2 Emissions* report,[16] it appears that, where there is no existing control technology in place, 90–95 percent control can generally be achieved at cost-effectiveness values that are in the hundreds of dollars per ton range or less.[17] We are thus proposing a presumption that, for uncontrolled utility boilers, an SO_2-control level in the 90–95 range is generally achievable. If you wish to demonstrate a BART level of control that is less than any presumption established the final guidelines, you would need to demonstrate the source-specific circumstances with respect to costs, remaining useful life, non-air quality environmental impacts, or energy impacts that would justify less stringent controls than for a typical utility boiler. We believe that the ''consideration of cost'' factor for source-by-source BART, which is a technology-based approach, generally requires selection of control measures that are within this level of cost effectiveness. We recognize, however, that the population of utility boilers subject to BART may have case-by-case variations (for example, type of fuel used, severe space limitations, and presence of existing control equipment) that could affect the costs of applying retrofit controls. We invite comments on whether the 90–95 percent presumption is appropriate, or whether another presumption should be established instead. If commenters want to offer a different presumption they should provide documentation supporting the basis for their proposal.

For evaluating the significance of the costs of compliance, EPA requests

[16] Documentation of the presumption that 90–95 percent control is achievable is contained in a recent report entitled *Controlling SO_2 Emissions: A Review of Technologies,* EPA–600/R–00–093, available on the internet at *http://www.epa.gov/ORD/WebPubs/so2*. This report summarizes percentage controls for flue gas desulfurization (FGD) systems worldwide, provides detailed methods for evaluating costs, and explains the reasons why costs have been decreasing with time.

[17] The EPA has used the cost models in the *Controlling SO_2 Emissions* report to calculate cost-effectiveness ($/ton) estimates for FGD technologies for a number of example cases. (See note to docket A–2000–28 from Tim Smith, EPA/OAQPS, December 29, 2000).

comment on whether the final rule should contain specific criteria, and on whether such criteria would improve implementation of the BART requirement. For example, in the work of the Western Regional Air Partnership (WRAP),[18] a system is described which views as ''low cost'' those controls with an average cost effectiveness below $500/ton, as ''moderate'' those controls with an average cost effectiveness between $500 to 3000 per ton, and as ''high'' those controls with an average cost effectiveness greater than $3000 per ton.

c. *In selecting a ''best'' alternative, should I consider the affordability of controls?* Even if the control technology is cost effective, there may be cases where the installation of controls would affect the viability of continued plant operations.

As a general matter, for plants that are essentially uncontrolled at present, and emit at much greater levels per unit of production than other plants in the category, we are unlikely to accept as BART any analysis that preserves a source's uncontrolled status. While this result may predict the shutdown of some facilities, we believe that the flexibility provided in the regional haze rule for an alternative reduction approach, such as an emissions trading program, will minimize the likelihood of shutdowns.

Nonetheless, we recognize there may be 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. These effects would include effects on product prices, the market share, and profitability of the source. We do not intend, for example, that the most stringent alternative must always be selected, if that level would cause a plant to shut down, while a slightly lesser degree of control would not have this effect. Where there are such unusual circumstances that are judged to have a severe effect on 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, so long as you provide an economic analysis that demonstrates, in sufficient detail for a meaningful public review, the specific economic effects, parameters, and reasoning. (We recognize that this review process must preserve the confidentiality of sensitive business information). Any analysis should consider whether other competing plants in the same industry may also be required to install BART controls.

V. Cumulative Air Quality Analysis

A. What Air Quality Analysis Do We Require in the Regional Haze Rule for Purposes of BART Determinations?

In the regional haze rule, we require the following in 40 CFR 51.308(e)(1)(ii)(B):

> An analysis of the degree of visibility improvement that would be achieved in each mandatory Class I Federal area as a result of the emission reductions from all sources subject to BART located within the region that contributes to visibility impairment in the Class I area, based on the * * * [results of the engineering analysis required by 40 CFR 51.308(e)(1)(ii)(A)] * * *

This means that the regional haze rule requires you to conduct a regional modeling analysis which addresses the total cumulative regional visibility improvement if all sources subject to BART were to install the ''best'' controls selected according to the engineering analysis described above in section IV of these guidelines. We are developing guidelines for regional air quality modeling.[19]

B. How Do I Consider the Results of This Analysis in My Selection of BART for Individual Sources?

You use a regional modeling analysis to assess the *cumulative* impact on visibility of the controls selected in the engineering analysis for the time period for the first regional haze SIP, that is, the time period between the baseline period and the year 2018. You use this cumulative impact assessment to make a determination of whether the controls you identified, in their entirety, provide a sufficient visibility improvement to justify their installation. We believe that there is a sufficient basis for the controls if you can demonstrate for any Class I area that any of the following criteria are met:

(1) The cumulative visibility improvement is a substantial fraction of the achievable visibility improvement from all measures included in the SIP, or is a substantial fraction of the visibility goal selected for any Class I area (EPA believes that for such situations, the controls would be essential to ensure progress towards a long-term improvement in visibility); OR

(2) The cumulative visibility improvement is necessary to prevent any degradation from current conditions on the best visibility days.

Note that under 40 CFR 51.308(e)(1)(ii)(B), the passage cited above, the rule does not provide for modeling of subgroupings of the BART population within a region, nor for determinations that some, but not all, of the controls selected in the engineering analysis may be included in the SIP. Thus, to comply with 40 CFR 51.308(e)(1), the visibility SIP must provide for BART emission limitations for *all* sources subject to BART (or demonstrate that BART-level controls are already in place and required by the SIP), unless you provide a demonstration that *no* BART controls are justifiable based upon the cumulative visibility analysis.

VI. Enforceable Limits/Compliance Date

To complete the BART process, you must establish enforceable emission limits and require compliance within a given period of time. In particular, 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. In addition, you must require compliance with the BART emission limitations no later than 5 years after EPA approves your SIP. If technological or economic limitations in the application of a measurement methodology to a particular emission unit would make an emissions limit infeasible, you may prescribe a design, equipment, work practice, operation standard, or combination of these types of standards. You should ensure that any BART requirements are written in a way that clearly specifies the individual emission unit(s) subject to BART review. Because the BART requirements are ''applicable'' requirements of the CAA, they must be included as title V permit conditions according to the procedures established in 40 CFR part 70 or 40 CFR part 71.

Section 302(k) of the CAA requires emissions limits such as BART to be met on a continuous basis. Although this provision does not necessarily require the use of continuous emissions monitoring (CEMs), it is important that sources employ techniques that ensure compliance on a continuous basis. Monitoring requirements generally applicable to sources, including those that are subject to BART, are governed by other regulations. See, e.g., 40 CFR

[18] *Technical Support Documentation. Voluntary Emissions Reduction Program for Major Industrial Sources of Sulfur Dioxide in Nine Western States and a Backstop Market Trading Program. An Annex to the Report of the Grand Canyon Visibility Transport Commission.* Section 6A.

[19] (The current draft of this document is entitled *Guidance for Attainment of Air Quality Goals for $PM_{2.5}$ and Regional Haze.* We expect this document will be released in final form before the publication of the final rule for the BART guidelines.)

part 64 (compliance assurance monitoring); 40 CFR 70.6(a)(3) (periodic monitoring); 40 CFR 70.6(c)(1) (sufficiency monitoring). Note also that while we do not believe that CEMs would necessarily be required for all BART sources, the vast majority of electric generating units already employ CEM technology for other programs, such as the acid rain program. In addition, emissions limits must be enforceable as a practical matter (contain appropriate averaging times, compliance verification procedures and recordkeeping requirements). In light of the above, the permit must:

- Be sufficient to show compliance or noncompliance (i.e., through monitoring times of operation, fuel input, or other indices of operating conditions and practices); and
- Specify a reasonable averaging time consistent with established reference methods, contain reference methods for determining compliance, and provide for adequate reporting and recordkeeping so that air quality agency personnel can determine the compliance status of the source.

VII. Emission Trading Program Overview

40 CFR 51.308(e)(2) allows States the option of implementing an emissions trading program or other alternative measure instead of requiring BART. This option provides the opportunity for achieving better environmental results at a lower cost than under a source-by-source BART requirement. A trading program must include participation by BART sources, but may also include sources that are not subject to BART. The program would allow for implementation during the first implementation period of the regional haze rule (that is, by the year 2018) instead of the 5-year compliance period noted above. In this section of the guidance, we provide an overview of the steps in developing a trading program [20] consistent with 40 CFR 51.308(e)(2).

A. What Are the General Steps in Developing an Emission Trading Program?

The basic steps are to:

(1) Develop emission budgets;

(2) Allocate emission allowances to individual sources; and

(3) Develop a system for tracking individual source emissions and allowances. (For example, procedures for transactions, monitoring, compliance and other means of ensuring program accountability).

B. What Are Emission Budgets and Allowances?

An emissions budget is a limit, for a given source population, on the total emissions amount [21] that may be emitted by those sources over a State or region. An emission budget is also referred to as an ''emission cap.''

In general, the emission budget is subdivided into source-specific amounts that we refer to as ''allowances.'' Generally, each allowance equals one ton of emissions. Sources must hold allowances for all emissions of the pollutant covered by the program that they emit. Once you allocate the allowances, source owners have flexibility in determining how they will meet their emissions limit. Source owners have the options of:

—Emitting at the level of allowances they are allocated (for example, by controlling emissions or curtailing operations),
—Emitting at amounts less than the allowance level, thus freeing up allowances that may be used by other sources owned by the same owner, or sold to another source owner, or
—Emitting at amounts greater than the allowance level, and purchasing allowances from other sources or using excess allowances from another plant under the same ownership.

A good example of an emissions trading program is the acid rain program under title IV of the CAA. The acid rain program is a national program—it establishes a national emissions cap, allocates allowances to individual sources, and allows trading of allowances between all covered sources in the United States. The Ozone Transport Commission's NO_X Memorandum of Understanding, and the NO_X SIP call both provide for regional trading programs. Other trading programs generally have applied only to sources within a single State. A regional multi-State program provides greater opportunities for emission trading, and should be considered by regional planning organizations that are evaluating alternatives to source-specific BART. The WRAP has recommended a regional market trading program as a backstop to its overall emission reduction program for SO_2. Although regional trading programs require more interstate coordination, EPA has expertise that it can offer to States wishing to pursue such a program.

C. What Criteria Must Be Met in Developing an Emission Trading Program as an Alternative to BART?

Under the regional haze rule, an emission trading program must achieve ''greater reasonable progress'' (that is, greater visibility improvement) than would be achieved through the installation and operation of source-specific BART. The ''greater reasonable progress'' demonstration involves the following steps, which are discussed in more detail below:

—Identify the sources that are subject to BART,
—Calculate the emissions reductions that would be achieved if BART were installed and operated on sources subject to BART,
—Demonstrate whether your emission budget achieves emission levels that are equivalent to or less than the emissions levels that would result if BART were installed and operated,
—Analyze whether implementing a trading program in lieu of BART would likely lead to differences in the geographic distribution of emissions within a region, and
—Demonstrate that the emission levels will achieve greater progress in visibility than would be achieved if BART were installed and operated on sources subject to BART.

1. How Do I Identify Sources Subject to BART?

For a trading program, you would identify sources subject to BART in the same way as we described in sections II and III of these guidelines.

2. How Do I Calculate the Emissions Reductions That Would Be Achieved If BART Were Installed and Operated on These Sources?

For a trading program under 51.308(e)(2), you may identify these emission reductions by:

—Conducting a case-by-case analysis for each of the sources, using the procedures described above in these guidelines in sections II through V;
—Conducting an analysis for each source category that takes into account the available technologies, the costs of compliance, the energy impacts, the non-air quality environmental impacts, the pollution control equipment in use, and the remaining useful life, on a category-wide basis; or

[20] We focus in this section on emission cap and trade programs which we believe will be the most common type of economic incentive program developed as an alternative to BART.

[21] An emission budget generally represents a total emission amount for a single pollutant such as SO_2. As noted in the preamble to the regional haze rule (64 FR 35743, July 1, 1999) we believe that unresolved technical difficulties preclude inter-pollutant trading at this time.

—Conducting an analysis that combines considerations on both source-specific and category-wide information.

For a category-wide analysis of available control options, you develop cost estimates and estimates of energy and non-air quality environmental impacts that you judge representative of the sources subject to BART for a source category as a whole, rather than analyze each source that is subject to BART. The basic steps of a category-wide analysis are the same as for a source-specific analysis. You identify technically feasible control options and rank them according to control stringency. Next, you calculate the costs and cost effectiveness for each control option, beginning with the most stringent option. Likely, the category-wide estimate will represent a range of cost and cost-effectiveness values rather than a single number.[22] Next, you evaluate the expected energy and non-air quality impacts (both positive and negative impacts) to determine whether these impacts preclude selection of a given alternative.

The EPA requests comment on an approach to the category-wide analysis of BART that would allow the States to evaluate different levels of BART control options (*e.g.,* all measures less than $1000/ton vs. all measures less than $2000/ton vs. all measures less than $3000/ton) through an iterative process of assessing relative changes in cumulative visibility impairment. For example, States or regional planning organizations could use $1000 or $2000/ton as an initial cutoff for selecting reasonable control options. The States or regional planning organizations could then compare the across-the-board regional emissions and visibility changes resulting from the implementation of the initial control option and that resulting from the implementation of control options with a $3000/ton cutoff (or $1500/ton, etc). This approach would allow States and other stakeholders to understand the visibility differences among BART control options achieving less cost-effective or more cost-effective levels of overall control.

[22] We request comment on whether these guidelines should recommend a weighted average of the values instead of presenting the values as a range.

3. For a Cap and Trade Program, How Do I Demonstrate That My Emission Budget Results in Emission Levels That Are Equivalent To or Less Than the Emissions Levels That Would Result If BART Were Installed and Operated?

Emissions budgets must address two criteria. First, you must develop an emissions budget for a future year[23] which ensures reductions in actual emissions that achieve greater reasonable visibility progress than BART. This will generally necessitate development of a ''baseline forecast'' of emissions for the population of sources included within the budget. A baseline forecast is a prediction of the future emissions for that source population in absence of either BART or the alternative trading program. Second, you must take into consideration the timing of the emission budget relative to the timetable for BART. If the implementation timetable for the emission trading program is a significantly longer period than the 5-year time period for BART implementation, you should establish budgets for interim years that ensure steady and continuing progress in emissions reductions.

In evaluating whether the program milestone for the year 2018 provides for a BART-equivalent or better emission inventory total, you conduct the following steps:

—Identify the source population included within the budget, which must include all BART sources and may include other sources,
—For sources included within the budget, develop a base year[24] emissions inventory for stationary sources included within the budget, using the most current available emission inventory,
—Develop a future emissions inventory for the milestone year (in most cases, the year 2018), that is, an inventory of projected emissions for the milestone year in the absence of BART or a trading program,
—Calculate the reductions from the forecasted emissions if BART were installed on all sources subject to BART,
—Subtract this amount from the forecasted total, and
—Compare the budget you have selected and confirm that it does not exceed this level of emissions.

Example: For a given region for which a budget is being developed for SO_2, the most recent inventory is for the year 2002. The budget you propose for the trading program is 1.2 million tons. The projected emissions inventory total for the year 2018, using the year 2002 inventory and growth projections, is 4 million tons per year. Application of BART controls on the population of sources subject to BART would achieve 2.5 million tons per year of reductions. Subtracting this amount from the project inventory yields a value of 1.5 million tons. Because your selected budget of 1.2 million tons is less than this value, it achieves a better than a BART-equivalent emission total.

[23] As required by 40 CFR 51.308(e)(2)(iii), emissions reductions must take place during the period of the first long-term strategy for regional haze. This means the reductions must take place no later than the year 2018.

[24] The base year must reflect the year of the most current available emission inventory, in many cases the year 2002, and this base year should not be later than the 2000–2004 time period used for baseline purposes under the regional haze rule.

4. How Do I Ensure That Trading Budgets Achieve ''Greater Reasonable Progress?''

In some cases, you may be able to demonstrate that a trading program that achieves greater emissions progress may also achieve greater visibility progress without necessarily conducting a detailed dispersion modeling analysis. This could be done, for example, if you can demonstrate, using economic models, that the likely distribution of emissions when the trading program is implemented would not be significantly different than the distribution of emissions if BART was in place. If distribution of emissions is not substantially different than under BART, and greater emissions reductions are achieved, then the trading program would presumptively achieve ''greater reasonable progress.''

If the distribution of emissions is different under the two approaches, then the possibility exists that the trading program, even though it achieves greater emissions reductions, may not achieve better visibility improvement. Where this is the case, then you must conduct dispersion modeling to determine the visibility impact of the trading alternative. The dispersion modeling should determine differences in visibility between BART and the trading program for each impacted Class I area, for the worst and best 20 percent of days. The modeling should identify:

—The estimated difference in visibility conditions under the two approaches for each Class I area,
—The average difference in visibility over all Class I areas impacted by the region's emissions. [For example, if six Class I areas are in the region impacted, you would take the average of the improvement in deciviews over those six areas].

The modeling study would demonstrate ''greater reasonable progress'' if both of the following two criteria are met:

—Visibility does not decline in any Class I area

Example: In Class I area X, BART would result in 2.5 deciviews of improvement but the trading program would achieve 1.4 deciviews. The criterion would be met because the trading program results in improvement of 1.4 deciviews, rather than a decline in visibility.

—Overall improvement in visibility, determined by comparing the average differences over all affected Class I areas

Example: For the same scenario, assume that ten Class I areas are impacted. The average deciview improvement from BART for the ten Class I areas is 3.5 deciviews (the 2.5 deciview value noted above, and values for the remaining areas of 3.9, 4.1, 1.7, 3.3, 4.5, 3.1, 3.6, 3.8 and 4.5). The average of the ten deciview values for the trading program must be 3.5 deciviews or more.

5. How Do I Allocate Emissions to Sources?

Emission allocations must be consistent with the overall budget that you provide to us. We believe it is not appropriate for EPA to require a particular process and criteria for individual source allocations, and thus we will not dictate how to allocate allowances. We will provide information on allocation processes to State and local agencies, and to regional planning organizations.

6. What Provisions Must I Include in Developing a System for Tracking Individual Source Emissions and Allowances?

The EPA requests comment generally on what the BART guidelines should require in terms of the level of detail for the administration of a trading program and for the tracking of emissions and allowances. In general, we expect regional haze trading programs to contain the same degree of rigor as trading programs for criteria pollutants. In terms of ensuring the overall integrity and enforceability of a trading program, we expect that you will generally follow the guidance already being developed for other economic incentive programs (EIPs) in establishing a trading program for regional haze. In addition, we expect that any future trading programs developed by States and/or regional planning organizations will be developed in consultation with a broad range of stakeholders.

There are two EPA-administered emission trading programs that we believe provide good examples of the features of a well-run trading program. These two programs provide considerable information that would be useful to the development of regional haze trading programs as an alternative to BART.

The first example is EPA's acid rain program under title IV of the CAA. Phase I of the acid rain reduction program began in 1995. Under phase I, reductions in the overall SO_2 emissions were required from large coal-burning boilers in 110 power plants in 21 midwest, Appalachian, southeastern and northeastern States. Phase II of the acid rain program began in 2000, and required further reductions in the SO_2 emissions from coal-burning power plants. Phase II also extended the program to cover other lesser-emitting sources. Allowance trading is the centerpiece of EPA's acid rain program for SO_2. You will find information on this program in:

—Title IV of the CAA Amendments (1990),
—40 CFR part 73 at 58 FR 3687 (January 1993),
—EPA's acid rain website, at www.epa.gov/acidrain/trading.html.

The second example is the rule for reducing regional transport of ground-level ozone (NO_X SIP call). The NO_X SIP call rule requires a number of eastern, midwestern, and southeastern States and the District of Columbia to submit SIPs that address the regional transport of ground-level ozone through reductions in NO_X. States may meet the requirements of the rule by participating in an EPA-administered trading program. To participate in the program, the States must submit rules sufficiently similar to a model trading rule promulgated by the Agency (40 CFR part 96). More information on this program is available in:

—The preamble and rule in the **Federal Register** at 63 FR 57356 (October 1998),
—The NO_X compliance guide, available at www.epa.gov/acidrain/modlrule/main.html#126,
—Fact sheets for the rule, available at www.epa.gov/ttn/rto/sip/related.html#prop,
—Additional information available on EPA's web site, at www.epa.gov/acidrain/modlrule/main.html.

A third program that provides a good example of trading programs is the the Ozone Transport Commission (OTC) NO_X budget program. The OTC NO_X budget program was created to reduce summertime NO_X emissions in the northeast United States. The program caps NO_X emissions for the affected States at less than half of the 1990 baseline emission level of 490,000 tons, and uses trading to achieve cost-effective compliance. For more information on the trading provisions of the program, see:

—Memorandum of Understanding (MOU), available at www.sso.org/otc/att2.HTM,
—Fact sheets available at www.sso.org/otc/Publications/327facts.htm,
—Additional information, available at *www.epa.gov/acidrain/otc/otcmain.html.*

The EPA is including in the docket for this rulemaking a detailed presentation that has been used by EPA's Clean Air Markets Division to explain the provisions of NO_X trading programs with State and local officials. This presentation provides considerable information on EPA's views on sound trading programs.

The EPA recognizes that it is desirable to minimize administrative burdens for sources that may be subject to the provisions of several different emission trading programs. We believe that it is desirable for any emission trading program for BART to use existing tracking systems to the extent possible. At the same time, we request comment on whether States and/or regional planning organizations should conduct additional technical analyses (and, if so, to what extent) to determine whether the time periods for tracking of allowances under existing programs (i.e., annual allowances for SO_2 for the acid rain program, and allowances for the ozone season for NO_X) are appropriate for purposes of demonstrating greater reasonable regional progress vis a vis BART. The EPA expects that if such analyses are conducted, they would be conducted in conjunction with the timelines for development of SIPs for regional haze.

7. How Would a Regional Haze Trading Program Interface With the Requirements for ''Reasonably Attributable'' BART Under 40 CFR 51.302 of the Regional Haze Rule?

If a State elects to impose case-by-case BART emission limitations according to 40 CFR 51.308(e)(1) of the regional haze rule, then there should be no difficulties arising from the implementation of requirement for ''reasonably attributable'' BART under 40 CFR 51.302. However, if a State chooses an alternative measure, such as an emissions trading program, in lieu of requiring BART emissions limitation on specific sources, then the requirement for BART is not satisfied until alternative measures reduce emissions sufficient to make ''more reasonable progress than BART.'' Thus, in that period between implementation of an emissions trading program and the satisfaction of the overall BART requirement, an individual source could be required to install BART for reasonably attributable impairment under 40 CFR 51.302. Because such an overlay of the requirements under 40 CFR 51.302 on a trading program under 40 CFR 51.308 might affect the economic and other considerations that were used in developing the emissions trading program, the regional haze rule allows for a ''geographic enhancement'' under 40 CFR 51.308. This provision addresses the interface between a regional trading program and the requirement under 40 CFR 51.302 regarding BART for reasonably attributable visibility impairment. (See 40 CFR 51.308(e)(2)(v)).

The EPA recognizes the desirability of addressing any such issues at the outset of developing an emissions trading program to address regional haze. We note that the WRAP, the planning organization for the nine western States considering a trading program under 40 CFR 51.309 (which contains a similar geographic enhancement provision), has adopted policies which target use of the 51.302 provisions by the Federal Land Managers (FLMs). In this case for the nine WRAP States, the FLMs have agreed that they will certify reasonable attributable impairment only under certain specific conditions. Under this approach, the FLMs would certify under 40 CFR 51.302 only if the regional trading program is not decreasing sulfate concentrations in a Class I area within the region. Moreover, the FLMs will certify impairment under 40 CFR 51.302 only where: (1) BART-eligible sources are located ''near'' that class I area and (2) those sources have not implemented BART controls. In addition, the WRAP is investigating other procedures for States to follow in responding to a certification of ''reasonably attributable'' impairment if an emissions trading approach is adopted to address the BART requirement based on the sources' impact on regional haze.

The specific pollutants and the magnitude of impacts under the regional haze rule and at specific Class I areas may vary in different regions of the country. We expect that each State through its associated regional planning organization will evaluate the need for geographic enhancement procedures within any adopted regional emissions trading program.

List of Subjects in 40 CFR Part 51

Environmental protection, Administrative practice and procedure, Air pollution control, Carbon monoxide, Nitrogen dioxide, Particulate matter, Sulfur oxides, Volatile organic compounds.

Dated: June 22, 2001.

Christine T. Whitman,

Administrator.

In addition to the guidelines described above, part 51 of chapter I of title 40 of the Code of Federal Regulations is proposed to be amended as follows:

PART 51—REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS

1. The authority citation for part 51 continues to read as follows:

Authority: 23 U.S.C. 101; 42 U.S.C. 7410–7671q.

2. Section 51.302 is amended by revising paragraph (c)(4)(iii) to read as follows:

§ 51.302 Implementation control strategies for reasonably attributable visibility impairment.

* * * * *

(c) * * *

(4) * * *

(iii) BART must be determined for fossil-fuel fired generating plants having a total generating capacity in excess of 750 megawatts pursuant to ''Guidelines for Determining Best Available Retrofit Technology for Coal-fired Power Plants and Other Existing Stationary Facilities' (1980), which is incorporated by reference, exclusive of appendix E, which was published in the **Federal Register** on February 6, 1980 (45 FR 8210), except that options more stringent than NSPS must be considered. Establishing a BART emission limitation equivalent to the NSPS level of control is not a sufficient basis to avoid the detailed analysis of control options required by the guidelines. It is EPA publication No. 450/3–80–009b and is for sale from the U.S. Department of Commerce, National Technical Information Service, 5285 Port Royal Road, Springfield, Virginia 22161.

* * * * *

3. Section 51.308 is amended by adding paragraph(e)(1)(ii)(C) as follows:

§ 51.308 Regional haze program requirements.

* * * * *

(e) * * *

(1) * * *

(ii) * * *

(C) Appendix Y of this part provides guidelines for conducting the analyses under paragraphs (e)(1)(ii)(A) and (e)(1)(ii)(B) of this section. All BART determinations that are required in paragraph (e)(1) of this section must be made pursuant to the guidelines in appendix Y of this part.

* * * * *

[FR Doc. 01–18094 Filed 7–19–01; 8:45 am]

BILLING CODE 6560–50–P

ATTACHMENT G

May 24, 2002, District of Columbia Court of Appeals Decision (no. 99-1348), American Corn Growers Association vs. EPA

United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Argued February 25, 2002
Decided May 24, 2002

No. 99-1348
American Corn Growers Association,
Petitioner
v.

Environmental Protection Agency,
Respondent

State of Michigan, Department of
Environmental Quality, et al.,
Intervenors

Consolidated with Nos. 99-1349, 99-1350,
99-1351, 99-1352, 99-1357, 99-1358, 99-1359,
01-1111, 01-1112, 01-1113

On Petitions for Review of an Order of the
Environmental Protection Agency

Peter Glaser argued the cause for Industry petitioners and intervenors on the BART Issues in Case Nos. 99-1348, 99-1349, 99-1350, 99-1351, 99-1352, 99-1356, 99-1357, 99-1358 and 99-1359. With him on the joint briefs were Paul M. Seby, Henry V. Nickel, F. William Brownell, Michael L. Teague, Kevin L. Fast, David M. Flannery, Kathy G. Beckett, Scott D. Goldman, Harold P. Quinn, Jr., William H. Lewis, Jr., and Michael A. McCord.

Kevin L. Fast argued the cause for Industry petitioners in Case Nos. 01-1111, 01-1112 and 01-1113. With him on the joint briefs were Peter Glaser, Paul M. Seby, Henry V. Nickel, F. William Brownell, and Michael L. Teague.

David S. Baron argued the cause and filed the briefs for petitioner Sierra Club.

Jennifer M. Granholm, Attorney General, State of Michigan, Thomas L. Casey, Solicitor General, and John Fordell Leone, Assistant Attorney General, were on the briefs for intervenor State of Michigan.

Pamela S. Tonglao, Kenneth C. Amaditz, and H. Michael Semler, Attorneys, U.S. Department of Justice, argued the causes for respondents. With them on the brief was M. Lea Anderson, Attorney, U.S. Environmental Protection Agency.

Erick Titrud argued the cause for intervenors State of Maine, State of New Hampshire, State of Vermont, and Tribal and Environmental intervenors. With him on the joint brief were Ann Brewster Weeks, Vickie L. Patton, William G. Grantham, G. Steven Rowe, Attorney General, State of Maine, Philip T. McLaughlin, Attorney General, State of New Hampshire, Maureen D. Smith, Senior Assistant Attorney General, and William H. Sorrell, Attorney General, State of Vermont.

Peter Glaser, Henry V. Nickel, F. William Brownell, Michael L. Teague, Kevin L. Fast, Paul M. Seby, Harold P. Quinn, Jennifer M. Granholm, Attorney General, State of Michigan, John Fordell Leone, Assistant Attorney General, David M. Flannery, Kathy G. Beckett, William H. Lewis, Jr., and Michael A. McCord were on the joint brief for Industry and State intervenors, in support of respondents.

Mark L. Shurtleff, Attorney General, State of Utah, Fred Nelson, Assistant Attorney General, and Susan M. McMichael were on the brief for amicicuriae State of Utah and State of New Mexico Environment Department, in support of respondent EPA.

Before: Edwards, Randolph, and Garland, Circuit Judges.

Opinion for the Court filed Per Curiam.

Opinion concurring in part and dissenting in part filed by Circuit Judge Garland.

Per Curiam: In 1999, the Environmental Protection Agency promulgated a final rule to address regional haze. See Regional Haze Regulations, 64 Fed. Reg. 35,714 (July 1, 1999). The Haze Rule calls for states to play the lead role in designing and implementing regional haze programs to clear the air in national parks and wilderness areas that have been classified as "mandatory class I

Federal areas,"[1] such as Yellowstone National Park, Grand Canyon National Park, and Shenandoah National Park. See 40 C.F.R. ss 81.401-.437 (listing areas that have been designated as Class I areas where visibility is an important value). Numerous petitioners now challenge the Haze Rule. We vacate the rule in part and sustain it in part.

I. Introduction

"Regional haze," as EPA defines it, is visibility impairment caused by geographically dispersed sources emitting fine particles and their precursors into the air. See 64 Fed. Reg. at 35,715. The emission and movement of sulfur dioxide, oxides of nitrogen, and fine particulate matter from sources, such as power plants, contribute to haze. See id. Fine particulate matter scatters and absorbs light. See id.

Haze has degraded visibility in most of the country's national parks and wilderness areas. See id. The average visual range in many Class I areas in the western United States is 100 to 150 kilometers - which is just one-half to two-thirds the estimated visual range that would exist without manmade air pollution. See id. In most of the eastern United States, the average visual range is less than 30 kilometers - or about one-fifth the visual range that would exist under estimated natural conditions. See id.

Before 1977, the Clean Air Act (the "CAA" or the "Act") "did not elaborate on the protection of visibility as an air-quality related value." Chevron U.S.A., Inc. v. EPA, 658 F.2d 271, 272 (5th Cir. 1981). But in 1977, "[i]n response to a growing awareness that visibility was rapidly deteriorating in many places, such as wilderness areas and national parks," id. at 272, Congress added s 169A to the Act. See Clean Air Act Amendments of 1977, Pub. L. No. 95-95, s 128, 91 Stat. 685, 742 (current version at 42 U.S.C. s 7491). Section 169A established as a national goal the "prevention of any future, and the remedying of any existing, impairment in visibility in mandatory class I areas which impairment results from man-made air pollution." See 91 Stat. at 742 (current version at 42 U.S.C. s 7491(a)(1)). Congress directed EPA to issue regulations requiring states to submit State Implementation Plans ("SIPs") containing emission limits, schedules of compliance, and other measures necessary to make reasonable progress toward meeting the national visibility goal. See 91 Stat. at 743 (current version at 42 U.S.C. s 7491(b)(2)). In addition, Congress required states to address possible visibility impairment caused by currently-operating large stationary sources which had been in operation between 1962 and 1977. See 91 Stat. at 743 (current version at 42 U.S.C. s 7491(b)(2)(A)).

Congress also gave EPA the responsibility of promulgating regulations under s 169A to "assure ... reasonable progress toward meeting the national goal." See 91 Stat. at 742-43 (current version at 42 U.S.C. s 7491(a)(4)). EPA issued its first regulations in 1980. See 45 Fed. Reg. 80,084 (Dec. 2, 1980). The 1980 visibility regulations, which apply to states containing at least one Class I area, addressed visibility impairment reasonably attributable to one source, or to a small number of sources. See id. at 80,085. EPA limited the reach of the 1980 regulations to impairment attributable to specific sources and deferred any action on regional haze attributable to multiple sources located across broad geo-graphic regions because there was insufficient data regarding the relationship between emitted pollutants, pollutant trans-port and visibility impairment. See id. at 80,086.

In 1990, Congress amended the Clean Air Act again, adding s 169B in an attempt to prompt EPA to further address visibility impairment in national parks and wilderness areas. See Clean Air Act Amendments, Pub. L. No. 101-549, s 816, 104 Stat. 2695 (1990) (current version at 42 U.S.C. s 7492). Section 169B requires, among other things, that EPA under-take research to identify "sources" and "source regions" of visibility impairment in Class I areas, consider designating transport commissions to study the interstate movement of pollutants, and establish a transport commission for the Grand Canyon National Park. See 42 U.S.C. s 7492.

EPA established the Grand Canyon Visibility Transport Commission ("GCVTC") in 1991 to assess information about the adverse impacts on visibility in and around sixteen Class I areas on the Colorado Plateau region and to provide policy recommendations to EPA to address such impacts. See 56 Fed. Reg. 57,522 (Nov. 12, 1991). The GCVTC issued its report to EPA in 1996.

[1] "Class I" areas include all international parks, national wilder-ness areas which exceed 5,000 acres in size, national memorial parks which exceed 5,000 acres in size, and national parks which exceed 6,000 acres in size and which were in existence on August 7, 1977. See 42 U.S.C. s 7472(a). The term "mandatory class I Federal areas" is defined as "Federal areas which may not be designated as other than class I." Id. s 7491(g)(5). At the time the Haze Rule was promulgated, there were 156 Class I areas across the country. See 64 Fed. Reg. at 35,714.

Then in 1997 EPA issued a notice of proposed rulemaking with regard to regional haze, see 62 Fed. Reg. 41,138 (July 31, 1997), noting that advances in scientific and technical knowledge, including analyses provided by the GCVTC, had made it possible for EPA to target region-wide visibility impairment. After receiving more than 1,300 comments to the proposed rule, EPA published the final Haze Rule on July 1, 1999. See 64 Fed. Reg. at 35,714. The final Haze Rule reaches all states because, EPA concluded, all states contain sources whose emissions are "reasonably anticipated to contribute to regional haze in a Class I area." Id. at 35,721. Under the Haze Rule, a state must develop and submit a SIP that provides for reasonable progress toward achieving "natural visibility conditions" in the national parks and wilderness areas in that state. See 40 C.F.R. s 51.308(d)(1). SIPs addressing regional haze in an "attainment" area must be submitted within one year of the date the area is designated as "attainment," and revised SIPs for "non-attainment" areas must be submitted within three years after the designation. See id. s 51.308(b)(1)-(2).

The Haze Rule, for the most part, does not specify what control measures a state must implement in its initial SIP. See 64 Fed. Reg. at 35,721 (noting that the determination of what specific control measures must be implemented "can only be made by a State once it has conducted the necessary technical analyses of emissions, air quality, and the other factors that go into determining reasonable progress"). But the rule does require states to: (1) provide for an improvement in visibility in the 20 percent most impaired days; (2) ensure that there is no degradation in visibility during the 20 percent clearest days; and (3) determine the annual rate of visibility improvement that would lead to "natural visibility" conditions in 60 years. See 40 C.F.R. s 51.308(d)(1); see also id. s 51.301; 64 Fed. Reg. at 35,734. A state may not adopt a rate of improvement that would achieve natural visibility conditions in more than 60 years unless it demonstrates that the 60-year rate is unreasonable. See 40 C.F.R. s 51.308(d)(1)(ii).

The Haze Rule also provides that each state must develop a long-term strategy for achieving its visibility improvement goals. This strategy must include the identification of all major stationary sources subject to Best Available Retrofit Technology ("BART") requirements. See id. s 51.308(e). In identifying sources subject to BART, the Haze Rule calls for states to use a group rather than a source-by-source approach. See 64 Fed. Reg. at 35,740 (providing that a state should find a source subject to BART "if it can be shown that the source emits pollutants within a geographic area from which pollutants can be emitted and transported downwind to a Class I area") (italics added). In addition, when establishing emission limits for BART sources, states must consider the improvement in visibility that would result if the technology were used at all comparable BART sources (rather than the improvement that a particular device at a particular source would accomplish). See 40 C.F.R. s 51.308(e)(1)(ii)(B).

The various petitioners and intervenors in this consolidated case raise numerous challenges to the Haze Rule. In Part II we address the claim that EPA acted contrary to law in establishing a group rather than a source-by-source approach to BART determinations. In Part III we address the claims of industry petitioners in Case Nos. 01-1111, 01-1112, and 01-1113 that EPA acted without legal authority and in an arbitrary and capricious manner in promulgating the "natural visibility" goal and the "no degradation" requirement in the regional haze regulations. Finally, in Part IV, we address the challenges raised by the Sierra Club - namely that EPA failed to set reasonable criteria for measuring or assuring reasonable progress, and that EPA acted contrary to law in extending the statutory deadline for submission of state haze control plans.

II. BART Issues

Under s 169A of the Act, each state must review all BART-eligible sources - meaning all major stationary sources built between August 1962 and August 1977 - to determine whether the sources emit "any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility" in a Class I area.[2] 42 U.S.C. s 7491(b)(2)(A). After deciding that a BART-eligible source emits a pollutant which may reasonably be anticipated to cause or contribute to Class I visibility impairment, the state then must determine what is the best available retrofit technology for controlling emissions from that source. See id. Under the Act, states must take the following five factors into consideration when deciding what BART controls to place on a source:

> the costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use 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.

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[2] A "major stationary source" is a source that has the potential to emit 250 tons or more of any pollutant. See 42 U.S.C. s 7491(g)(7).

Id. s 7491(g)(2).

The Haze Rule interprets and implements these statutory BART provisions in two main ways. First, the Haze Rule requires states to "find that a BART-eligible source is 'reasonably anticipated to cause or contribute' to regional haze if it can be shown that the source emits pollutants within a geographic area from which pollutants can be emitted and transported downwind to a Class I area." 64 Fed. Reg. at 35,740 (italics added). In other words, states must subject BART-eligible sources to BART requirements even absent empirical evidence of that source's individual contribution to visibility impairment in a Class I area so long as the source is located within a region that may contribute to visibility impairment. See id. at 35,740; see also Br. for EPA at 26-27. EPA explained in the preamble to the Haze Rule that this sort of "collective contribution" approach was "consistent with that taken in the programs for acid rain and ozone, programs which also address regional air quality problems caused by transported pollutants." 64 Fed. Reg. at 35,740; see also 63 Fed. Reg. at 57,376.

Second, the Haze Rule provides that once a state has decided that a particular source is subject to BART and is considering what BART controls to place on that source, the state must analyze "the degree of visibility improvement that would be achieved in each mandatory Class I Federal area as a result of the emission reductions achievable from all sources subject to BART located within the region that contributes to visibility impairment in the Class I area." 40 C.F.R. s 51.308(e)(1)(ii)(B) (italics added). This means that of the five statutory factors to be considered by states when deter-mining BART controls, see 42 U.S.C. s 7491(g)(2), only four factors (the costs of compliance, the environmental impacts of compliance, any existing pollution control technology in use at the source, and the remaining useful life of the source) are considered on a source-specific basis. The Haze Rule re-quires states to consider the fifth statutory factor (the degree in improvement) on a group or "area wide" basis.

Industry petitioners attack EPA's decision to use a group rather than a source-by-source BART approach, arguing that the language, statutory structure, and legislative history of s 169A make it clear that the Haze Rule runs afoul of the Act. See Br. for Industry Pet'rs and Intervenor in Case Nos. 99-1348, et al. at 13. For the reasons that follow, we grant the petition for review, vacate the BART rules, and remand to EPA.

In the Haze Rule, EPA extracts one of the five statutory factors listed in s 169A(g)(2) and treats it differently than the other four. See 64 Fed. Reg. at 35,741 (providing that only "the degree in improvement in visibility that would be expect-ed at each Class I area as a result of imposing BART" is to be considered on a group rather than a source-specific basis). In effect, EPA bifurcates the states' determination of the appropriate BART emission limitations for specific sources. States must first estimate possible emission reductions on a source-by-source basis based on the application of the technology, the cost, time for compliance, energy and nonair environmental impacts, and the remaining useful life of the source. See id.; see also 40 C.F.R. s 51.308(e)(1)(ii)(A). "Taking these factors into account allows the State to arrive at an estimate of the 'best system' of retrofit control technology for a particular source." 64 Fed. Reg. at 35,741. States must then calculate the degree in improvement in visibility that would be expected at each Class I area as a result of imposing BART on all sources subject to BART. See id.; see also 40 C.F.R. s 51.308(e)(1)(ii)(B).

EPA argues that its bifurcated approach to determining appropriate BART controls is permissible because s 169A(g)(2) is unclear about how a state must analyze anticipated visibility improvement. See Chevron U.S.A., Inc. v. Natural Res. Def. Council, 467 U.S. 837, 842-43 (1984). We cannot agree. The Haze Rule's splitting of the statutory factors is consistent with neither the text nor the structure of the statute. See 42 U.S.C. s 7491(g)(2). All five s 169A(g)(2) factors inform the states' inquiries into what BART controls are appropriate for particular sources. Al-though no weights were assigned, the factors were meant to be considered together by the states. The language of s 169A(g)(2) can be read in no other way. To treat one of the five statutory factors in such a dramatically different fashion distorts the judgment Congress directed the states to make for each BART-eligible source. This is most apparent with respect to the states' duty to take into account "the costs of compliance" in deciding not only whether to order an individual source to install any new pollution control equipment, but also what type of equipment - or as the statute puts it, what type of "retrofit technology." How is a state to determine what is too costly (and what is not) for a particular source? The statute answers that the state must consider the degree of improvement in visibility in national parks and wilderness areas that would result from the source's installing and operating the retrofit technology. EPA has a far different answer: in assessing the cost of compliance imposed on a source, the state may not consider the degree to which new equipment at a particular source would help cure the haze in some distant national park. Under EPA's take on the statute, it is therefore entirely possible that a source may be forced to spend millions of dollars for new technology that will have no appreciable effect on the haze in any Class I area. [3]A similar problem arises when a state considers, as it must, the "existing pollution control technology in use at the source." How is a state to decide whether the source already has installed sufficient devices without determining how much, if at all, the source is contributing to visual impairment in downwind Class I areas? As the industry petitioners correctly note, there is no point during the Haze Rule's BART determination "in which it could be demonstrated that the degree of improvement in visibility obtained from installing a particular set of emissions controls at a source with 'exceedingly low' or even merely theoretical visibility impacts is not justified by the cost of BART in light of those low or theoretical impacts." Br. for Industry Pet'rs and Intervenor in Case Nos. 99-1348, et al. at 17-18.

The Haze Rule's treatment of s 169A(g)(2)'s degree-of-improvement calculation is, the industry petitioners argue, not the only respect in which the rule is inconsistent with the Act. As they see it, the Haze Rule also unlawfully constrains the states' statutory authority because under the Act it is the states - not EPA - who must determine which BART-eligible sources should be subject to BART. See 42 U.S.C. s 7491(b)(2)(A) (providing that each BART-eligible source that, "as determined by the State ... emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility," shall install and operate the best available retrofit technology (italics added)); see also id. s 7491(g)(2) (listing the factors that "the State ... shall take into consideration" in determining BART controls (italics added)).

We agree with these petitioners that the Haze Rule's BART provisions are inconsistent with the Act's provisions giving the states broad authority over BART determinations. See id. s 7491(b)(2)(A); see also id. s 7491(g)(2). The Haze Rule ties the states' hands and forces them to require BART controls at sources without any empirical evidence of the particular source's contribution to visibility impairment in a Class I area. See 64 Fed. Reg. at 35,740; see also Br. for EPA at 26-27. If the Haze Rule contained some kind of a mechanism by which a state could exempt a BART-eligible source on the basis of an individualized contribution determination, then perhaps the plain meaning of the Act would not be violated. But the Haze Rule contains no such mechanism. Section 169A(c)(1) - on which EPA relies - is a procedure by which the Administrator, with the approval of federal land managers, can exempt a source from BART requirements. See 42 U.S.C. s 7491(c)(1) ("The Administrator may, by rule, after notice and opportunity for public hearing, exempt any major stationary source from [the BART requirements], upon his determination that such source does not or will not, by itself or in combination with other sources, emit any air pollutant which may reasonably be anticipated to cause or contribute to a significant impairment of visibility in any mandatory class I Federal area."); see also id. s 7491(c)(3). It does not provide the states with a means by which they can exempt sources based on individual contribution determinations.

Our conclusion that the Haze Rule's BART provisions impermissibly constrain state authority is reinforced by the Conference Report on the 1977 amendments to the Act. See Demby v. Schweiker, 671 F.2d 507, 510 (D.C. Cir. 1981). The Report explains:

> The agreement clarifies that the State, rather than the Administrator, identifies the source that impairs visibility in the Federal class I areas identified.
>
> In establishing emission limitations for any source which impairs visibility, the State shall determine what constitutes "best available retrofit technology" ... in establishing emission limitations on a source-by-source

[3] EPA's rule requires states to consider the cost of compliance in terms of the likely emission reductions which would be achieved by the imposition of BART, no matter whether this reduction would enhance visibility in downwind national parks. See 64 Fed. Reg. at 35,741 (explaining that the four factors, including cost, "should be taken into account for each source subject to BART in order to compare tradeoffs between the control efficiencies and costs associated with various control alternatives"). The preamble to the rule provides very little guidance about how states are to calculate the degree of improvement in visibility under the regime EPA contemplates. The preamble tells the states only this:

> To calculate the degree of improvement in visibility that would be expected at each Class I area as a result of imposing BARTon all sources subject to BART, the State should estimate the possible emissions reductions resulting from the application of BART at all subject sources located within the region that contributes to visibility impairment in the Class I area. The State should work on its own or in conjunction with other States, such as a regional planning body, to determine the geographic scope of the region that contributes to each Class I area. The States should consult with one another to determine the emission reductions achievable from sources subject to BART in other states. Id.

basis to be included in the State implementation plan so as to carryout the requirements of this section.

H.R. Conf. Rep. No. 95-564 (1977), reprinted in 3 Senate Comm. on Env't and Pub. Works, A legislative History of the Clean Air Act Amendments of 1977, at 535 (1978) [hereinafter "1977 Legislative History"]. The "agreement" to which the Conference Report refers was an agreement to reject the House bill's provisions giving EPA the power to determine whether a source contributes to visibility impairment and, if so, what BART controls should be applied to that source. See id. at 533-35. Pursuant to the agreement, language was inserted to make it clear that the states - not EPA - would make these BART determinations. See id. at 533-35; see also H.R. Res. 4151, 95th Cong. (1977), reprinted in 1977 Legislative History at 1985, 2325-30. The Conference Report thus confirms that Congress intended the states to decide which sources impair visibility and what BART controls should apply to those sources. The Haze Rule attempts to deprive the states of some of this statutory authority, in contravention of the Act.

In sum, we conclude that the Haze Rule's BART provisions are contrary to the text, structure and history of s 169A of the Act because the rule isolates s 169A(g)(2)'s benefit calculation and constrains authority Congress conferred on the states. Although petitioners also contended that no concept of a group or area-wide BART determination could ever be consistent with the Act,[4] we need not decide that broad issue today. We hold only that the Haze Rule's treatment of s 169A(g)(2)'s benefit calculation and its infringement on states' authority under the Act render the BART provisions of the rule impermissible.

III. The "Natural Visibility" Goal and the "No Degradation" Requirement

The industry petitioners in Case Nos. 01-1111, 01-1112, and 01-1113 ("Reconsideration Petitioners") cite four grounds in support of their claim that the "natural visibility" goal and the "no degradation" requirement in the Haze Rule should be vacated as "arbitrary and capricious" and otherwise not in accordance with law: (1) EPA exceeded its authority under s 169A(a)(1) and adopted regulations that conflict with the PSD program in establishing "natural visibility" as the goal of the regional haze program; (2) the regulations impermissibly constrain state discretion in requiring that the states develop their visibility programs using the "no degradation" requirement as a bench mark; (3) EPA has no authority to impose upon the states the goal of achieving "natural visibility" conditions, and thereby restrict the opportunity of some states to participate in the planning process aimed at addressing regional haze; and (4) EPA promulgated the Haze Rule without providing adequate notice and an opportunity for comment. We find no merit in these claims and, accordingly, deny industry petitioners' challenge to the "natural visibility" goal and the "no degradation" requirement.

Before we turn to the merits of petitioners' claims, we must first address EPA's contentions that petitioners' challenge to the natural visibility goal and their claims of inadequate notice are barred because they were not properly raised before the agency. We find no merit in EPA's contentions. Petitioners argued that the Haze Rule conflicted with the PSD program in both their comments to the agency before the regulations were issued and in their petition for reconsideration. See Supplemental Comments of the Utility Air Regulatory Group at 22, reprinted in Joint Appendix ("J.A.") 156; Petition for Reconsideration of the Regional Haze Regulations Submitted by Utility Air Regulatory Group & Nation-al Mining Ass'n at 10-11, reprinted in J.A. 97-98. Petitioners also sought notice and comment in connection with these portions of the Haze Rule in their petition for reconsideration. See Petition for Reconsideration of the Regional Haze Rule Submitted by the Center for Energy and Economic Development at 11-14, reprinted in J.A. 116-19.

On the merits, we reject petitioners' claim that EPA had no authority under s 169A to adopt the natural visibility goal. EPA acted under express congressional authorization in promulgating the challenged regulations. See 42 U.S.C. s 7491(a)(4). In a case such as this, where

> "there is an express delegation of authority to the agency to elucidate a specific provision of the statute by regulation," Chevron, 467 U.S. at 843-844, ... any ensuing regulation is binding in the courts unless procedurally defective, arbitrary or capricious in substance, or manifestly contrary to the statute.

[4] The industry petitioners argued that source-by-source BART determinations are required by the statute and that no concept of area-wide BART determinations is permissible. See Brief for Industry Pet'rs and Intervenor in Case Nos. 99-1348, et al. at 14 (arguing that s 169A makes it clear that BART determinations "must be made on a source-by-source basis"). Cf. Train v. Natural Res. Def. Council, 421 U.S. 60, 64 (1975) (discussing the history of the Clean Air Act and how the premise of the Act was to give states and local governments responsibility over preventing air pollution "at its source").

United States v. Mead Corp., 533 U.S. 218, 227 (2001) (foot-note omitted). The natural visibility goal is neither "manifestly contrary to the statute" nor "arbitrary or capricious in substance." Indeed, the goal is an eminently reasonable elucidation of the statute.

The statutory goal enunciated in s 169A(a)(1) is quite clear: "the prevention of any future, and the remedying of any existing, impairment of visibility." 42 U.S.C. s 7491(a)(1). Petitioners argue that a "natural visibility" goal cannot be gleaned from this statutory standard. This claim is specious. Agency regulations that aim to remedy any existing impairment of visibility and prevent any future impairment - as the statute commands - will of necessity aim to achieve a state of natural visibility. There is no material inconsistency between the statutory and regulatory goals, for the latter merely elucidates the former.

The petitioners also claim that Congress did not intend for the statutory goal of s 169A(a) to displace the objectives of the PSD program. Therefore, according to petitioners, the natural visibility goal and the no degradation requirement cannot be squared with the PSD program, because that program recognizes that some impairment of visibility would be acceptable in Mandatory Federal Class I areas. We reject this argument, because EPA has reasonably construed the PSD program and the disputed regional haze rules as complementary regulatory regimes.

There are two things worth noting at the outset. First, the natural visibility goal is not a mandate, it is a goal. As EPA has explained, this goal serves as the foundation for analytical tools to be used by the states to set reasonable progress goals. 64 Fed. Reg. at 35,732-33 Petitioners' claim that the agency is without authority to mandate attainment of the national goal is therefore meritless.

Second, the statute specifically calls for regulations to assure "reasonable progress toward meeting the national goal" of remedying any current and preventing any future impairment of visibility. 42 U.S.C. s 7491(a)(4). The no degradation provision requires implementation plans to "pro-vide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period." 40 C.F.R. s 51.308(d)(1). This regulation plainly and permissibly serves to assure the reasonable progress sought by Congress.

The PSD program was adopted pursuant to the 1977 amendments to the Act. See generally Ala. Power Co. v. Costle, 636 F.2d 323, 349-51 (D.C. Cir. 1979). The program generally controls any additional deterioration of air quality by establishing maximum allowable increases of certain pollutants in specified areas. See 42 U.S.C. s 7473(b). It is therefore true, as industry petitioners point out, that the PSD program may sometimes allow for limited air quality deterioration. EPA, however, has taken pains to explain that the PSD program and the Haze Rule are not at odds:

> Section 169A of the CAA requires the EPA to promulgate regulations to ensure that the States revise their implementation plans to contain those measures necessary to make reasonable progress toward the national visibility goal. In addition to the remedying of any existing visibility impairment, that goal requires the prevention of any future visibility impairment in mandatory Class I Federal areas. As part of the overall strategy to effectuate that goal, the final rule requires States to identify all anthropogenic sources of visibility impairment. The States accordingly should take into account the cumulative effect of all existing, man-made sources of air pollution in developing their regional haze implementation plan as well as potential new sources.
>
> With respect to the comment that EPA lacks authority to impose a welfare-based standard which renders other requirements of the CAA such a[s] PSD and NSPS largely superfluous, EPA notes that when Congress amended the CAA in 1977 to provide for the protection of visibility, it was aware of both the PSD and NSPS provisions. Nevertheless, Congress required EPA to issue regulations to address visibility. In contrast, the final regional haze rule requires States to take into account the visibility impact of emissions from both existing and new sources, and stationary and nonstationary sources. This is only one of many instances under the CAA in which Congress has provided for overlapping regulation. Indeed, the PSD and NSPS programs both focus on the control of emissions from new stationary sources. EPA believes that the regional haze rule and these other provisions are complementary means of improving air quality.
>
> Commenters raised a number of specific questions regarding the interaction of the PSD program and the regional haze rule. One commenter asked the EPA to address the relationship of allowable Class I impacts to the proposed visibility impact limits. All PSD areas are categorized as Class I, II, or III. The classification of an area determines the corresponding

maximum allowable increases, or increment, of air quality deterioration. Only a relatively small increment of air quality deterioration is permissible in Class I areas. These increments are measured over annual, 24-hour, and/or 3-hour aver- aging times. Nowhere, however, does the CAA provide that air quality must be allowed to deteriorate to the full extent allowed by the Class I increments standing alone. To read the statute in that manner would contravene both the general goals of the CAA to "protect and enhance" air quality (see section 101(b)(1)) but the specific long-term goal of section 169A is to eventually remedy existing visibility impairment in Class I areas. Accordingly, we believe that allowing localized air quality in- creases in the short-term due to the emissions from major new sources subject to PSD is not inconsistent with the regional haze program. The regional haze program is focused on long-term emission decreases from the entire regional emission inventory, comprised of major and minor stationary sources, area sources and mo- bile sources. We expect that long-term emission strategies for regional haze will derive substantial emission decreases from the inventory as a whole, and that these overall strategies will be able to accommodate some localized increases within the framework of a regional decrease. We also note that the overall inventory would decrease in cases where new sources are built that replace older, more polluting sources. Accordingly, we do not see any inherent conflict between the two pro- grams.

While the PSD program generally allows for a small increment of air quality deterioration in Class I areas, section 165 of the CAA also provides for the additional protection of air quality-related values, "including visibility," in Class I Federal areas beyond that provided by the increments. That is, where the FLM [Federal Land Manager] demonstrates that emissions from a new or modified source will have an adverse impact on air quality-related values (AQRVs), notwithstanding the fact that the emissions from the source do not cause or contribute to concentrations in excess of the increment for a Class I area, "a permit shall not be issued." Section 165(d). Thus, under PSD there can be no in- crease in emissions from the construction or modification of a major stationary source where that increase would result in adverse impacts on AQRVs in a Class I Federal area.

Responses to Significant Comments on the Notice of Pro-posed Rulemaking s I.F (Apr. 1999), reprinted in J.A. 1062-63.

The Government also reminds us that the PSD program "does not require that [visibility] deterioration occur. Nor does it create an entitlement to degrade air quality in general or visibility in particular, because nothing in the CAA pro- vides for issuance of a PSD permit as a matter of right." Br. for EPA at 59. We agree.

Petitioners cite Alabama Power in an attempt to support their claim that the existence of the PSD program effectively bars "natural visibility" as a viable regulatory goal. Alabama Power supports no such claim. Indeed, the court noted that "[s]ection 169A is available to protect visibility in Class I areas where visibility is an important characteristic, and the [agency] may choose to invoke [its] rulemaking authority ... to address this problem." 636 F.2d at 368. In acknowledging the availability of s 169A, the court implicitly embraced EPA's view that the visibility program is a supplement to the PSD program.

Industry petitioners additionally claim that the no degradation requirement conflicts with s 169A(g)(1)'s list of factors that states must consider when determining reasonable progress. Section 169A(g)(1) states:

> in determining reasonable progress there shall be taken into consideration the costs of compliance, the time necessary for compliance, and the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements.

42 U.S.C. s 7491(g)(1). Petitioners argue that, because "reasonable progress" could at times involve degradation, the "no degradation" requirement restricts the States' authority to apply the statutory criteria. We disagree.

As noted above, the statute commands EPA to promulgate regulations assuring "reasonable progress toward meeting the national goal." Id. s 7491(a)(4). The national goal includes "the prevention of any future ... impairment of visibility." Id. s 7491(a)(1). The no degradation requirement simply elucidates "reasonable progress." The requirement does not, however, in any way alter the list of s 169A(g)(1) criteria. In fact, the cited statutory factors do not include "degradation." Therefore, the States will be able to comply with the no degradation requirement while applying the s 169A(g)(1) criteria.

Next, although the petitioners assert that the Haze Rule somehow restricts the opportunity of some states to participate in the planning process aimed at addressing regional haze, we can find no real evidence in support of this claim.

This contention certainly offers no ground upon which to vacate the disputed regulations.

Finally, petitioners claim that they did not have fair notice and an adequate opportunity to comment on the regulatory goal of natural visibility, because "EPA provided no notice in its 1997 proposal that it intended to require States to achieve natural visibility conditions." Br. for Reconsideration Pet'rs at 25. Rather, according to petitioners, EPA merely pro-posed regulations patterned on the statutory goal enunciated in s 169A(a)(1), i.e., "'preventing any future, and remedying any existing, impairment of visibility."' Br. for Reconsideration Pet'rs at 25 (quoting old 40 C.F.R. s 51.300(a)(1)). This argument is meritless. As noted above, there is no material inconsistency between the statutory goal enunciated in s 169A(a)(1) and the regulatory goal of "natural visibility." The latter is a "logical outgrowth" of the former. Fertilizer Inst. v. EPA, 935 F.2d 1303, 1311 (D.C. Cir. 1991). There-fore, EPA did not violate any notice and comment requirements in adopting the natural visibility goal as a part of the Haze Rule.

If there is any tension between the Haze Rule and the PSD program, it is EPA's responsibility to harmonize the regulatory requirements. It has done so in a perfectly reasonable fashion. EPA's regulatory harmonization is both consistent with the statute and reasonable. Accordingly, we deny the petitions for review of the natural visibility goal and the no degradation requirement.

IV. The "Reasonable Progress" Criteria and the Extension of the Statutory Deadline

While the Industry Petitioners attack the Regional Haze Rule as overstepping EPA's statutory authority, Sierra Club argues that EPA has not gone far enough to meet its statutory responsibilities.

In its first cluster of attacks on the Haze Rule, Sierra Club contends that the Rule does not satisfy EPA's responsibility under CAA s 169A(a)(4) to "promulgate regulations to assure ... reasonable progress toward meeting the national [visibility] goal," 42 U.S.C. s 7491(a)(4), its responsibility under CAA s 169B(e)(1) to establish "criteria for measuring 'reasonable progress' toward the national goal," 42 U.S.C. s 7492(e)(1), and its obligation under the Administrative Procedure Act not to act in an "arbitrary or capricious" fashion, 5 U.S.C. s 706 (2)(A). Sierra Club argues that the Haze Rule's requirements for improvement in visibility during the 20 percent most impaired days and for no degradation during the 20 percent least impaired days, 40 C.F.R. s 51.308(d)(1); see also 64 Fed. Reg. at 35,734, do not qualify as "reasonable progress" criteria and are arbitrary and capricious. Similarly, it argues that the Rule's requirement that a state not adopt a rate of improvement that would take more than 60 years to achieve natural visibility unless the state demonstrates that the 60-year rate is unreasonable, 40 C.F.R. s 51.308(d)(1)(i)(b), (ii), does not meet the statutory mandates and lacks "requisite specificity" because a state would be "free to reject the 60 year time frame merely by claiming that such a schedule is not 'reasonable."' Reply Br. for Sierra Club at 5, 8.

We might well consider the latter attack unripe even without reference to our decision in Part II that the group-BART provisions of the Haze Rule are invalid. If in the future a state does conclude that it needs more than 60 years to achieve natural visibility, and if EPA decides to accept that conclusion, it will at that time be open to Sierra Club to challenge EPA's decision as arbitrary and capricious. In the meantime, this court will certainly "'benefit from postponing review until the policy in question has sufficiently crystallized."' Grand Canyon Air Tour Coalition v. FAA, 154 F.3d 455, 472 (D.C. Cir. 1998) (quoting Florida Power & Light Co. v. EPA, 145 F.3d 1414, 1421 (D.C. Cir. 1998)).

But in any event, our decision to invalidate the group-BART provisions renders this entire cluster of challenges unripe for disposition. Because those provisions were intimately related to EPA's assessment of what was necessary to achieve the goal of natural visibility, we cannot be sure whether on remand EPA will retain its current criteria for evaluating reasonable progress or adopt others. If the invalidation of the group-BART provisions causes EPA to doubt the efficacy of the remaining elements of the Haze Rule, perhaps EPA will see wisdom in some of Sierra Club's complaints and, for example, increase the percentage of days during which there must be improvement in visibility, or increase the specificity of its criteria for reasonable progress. In light of the uncertainty that our decision creates with respect to the form of the rule that may emerge upon remand, the only prudent course is for us to decline to address Sierra Club's challenges at this juncture.

Sierra Club's second major attack on the Haze Rule challenges EPA's determination to give states 3 years to file haze SIPs for areas designated "attainment" or "unclassifiable." We are troubled by EPA's action, which appears to contravene express statutory language, but in light of our decision regarding group-BART we leave this to EPA to reconsider on remand as well.

The Transportation Equity Act for the 21st Century, Pub. L. No. 105-178, 112 Stat. 107, 463 (1998) ("TEA-21"), provides that, for areas designated as "nonattainment" for the new national ambient air quality standard (NAAQS) for fine particulate matter, EPA shall require states to submit haze SIPs 3 years after the area has been so designated. See TEA-21 s 6102(c)(2) (incorporating the 3-year deadline of 42 U.S.C. s 7492(e)(2)). However, TEA-21 also expressly mandates that for any area designated as "attainment" or "unclassifiable" for that standard, EPA "shall require the [SIP] to be submitted 1 year after the area has been so designated." Id. Nonetheless, the Haze Rule permits a state to "choose to defer addressing the [Rule's] core requirements for regional haze ... and the requirements for BART" by submitting a so-called "commitment SIP," containing a "demonstration of ongoing participation in a regional planning process to ad-dress regional haze, and an agreement ... to continue participating," a "description of the regional planning process," and a "list of all BART-eligible sources within the state." 40 C.F.R. s 51.308(c), (c)(1). If a state submits such a commitment SIP, the deadline for submitting a haze SIP is extended from 1 year to 3. Id. s 51.308(c)(2); see Br. for EPA at 87; Br. for Sierra Club at 25.

On its face, this provision of the Haze Rule appears to extend the express statutory deadline for "attainment" and "unclassifiable" areas, an action which is beyond the agency's authority. See Sierra Club v. EPA, 129 F.3d 137, 140 (D.C. Cir. 1997) (holding that EPA cannot establish a "grace period" for compliance when not authorized to do so by the CAA); Sierra Club v. EPA, 719 F.2d 436, 469 (D.C. Cir. 1983) (reversing an EPA implementation plan that would have effectively extended the statutory deadline for state submissions under CAA amendments). The statute requires states to submit, by the 1-year deadline, SIPs "contain[ing] such emission limits, schedules of compliance, and other measures as may be necessary to carry out" the haze regulations. 42 U.S.C. s 7492(e)(2) (incorporated by reference into TEA-21 s 6102(c)(2)). A commitment SIP, which by definition ad-dresses neither the Haze Rule's core requirements for regional haze," nor its "requirements for BART," 40 C.F.R. s 51.308(c), does not appear to satisfy the statutory requirement. Cf. Natural Res. Def. Council, Inc. v. EPA, 22 F.3d 1125, 1134 (D.C. Cir. 1994) (holding, under CAA s 110(k)(4), that EPA cannot satisfy its responsibility to determine whether a state plan submission complies with the CAA unless the submission "contains something more than a mere promise to take appropriate but unidentified measures in the future," and that a submission containing nothing more than such a commitment cannot extend the statutory deadline).

Notwithstanding our doubts about the validity of this provision, we decline to vacate it in light of the uncertainty that our decision invalidating the group-BART provisions of the Haze Rule will cast upon the contents of the SIPs required of the states. With the Rule and hence the contents of the SIPs now altered and subject to revision on remand, the more prudent course for this court is simply to remand the dead-line-extension issue as well. This will permit the agency to reconsider its decision to extend the deadline at the same time that it decides what form the substantive requirements of a revised Haze Rule should take.

Garland, Circuit Judge, concurring in part and dissenting in part: In the Clean Air Act, Congress declared a national goal of restoring natural visibility in the country's largest national parks and wilderness areas. In Part II of today's opinion, the court adopts an interpretation of the Act that, in the view of the Environmental Protection Agency (EPA) and the National Academy of Sciences, will prevent the achievement of Congress' goal. If that interpretation were required by the statutory language, we would of course be compelled to adopt it. But such an interpretation is not required. To the contrary, EPA's construction of the Clean Air Act as permitting the group-BART provisions of the Haze Rule is a reasonable interpretation of the legislative language. It is therefore entitled to our deference under the standard announced in Chevron U.S.A. Inc. v. Natural Res. Def. Council, Inc., 467 U.S. 837, 842-43 (1984). Accordingly, while concur-ring in most of the court's opinion, I dissent from the conclusions it reaches in Part II.

A

Chevron instructs courts to apply a two-step framework when reviewing an agency's construction of a statute. First, we must ask "whether Congress has directly spoken to the precise question at issue," in which case we "must give effect to the unambiguously expressed intent of Congress." Id. at 842-43. However, if the "statute is silent or ambiguous with respect to the specific issue," we move to the second step and must defer to the agency's interpretation as long as it is "based on a permissible construction of the statute." Id. at 843; accord Barnhart v. Walton, 122 S.Ct. 1265, 1271-72 (2002).

My colleagues stop at Chevron's first step, concluding that the language of the Clean Air Act (CAA) can be read in only one way. They adopt the view of the industry petitioners that under the Act, BART ("best available retrofit technology") controls cannot be imposed on a source unless a state determines how much that particular source contributes to visual impairment in a downwind national park or wilderness area, as well as how much improvement in visibility would result from installing BART controls at that specific source. Op. at 10-11. EPA, by contrast, interprets the Clean Air Act as permitting a collective assessment of the impact that emissions from (and controls on) sources located in upwind regions have on visibility impairment in downwind areas.

Before considering the grounds for the court's decision, it is important to understand why EPA decided to require a collective contribution approach, rather than a tracing of the effects of each individual source's emissions. Congress added s 169A to the Clean Air Act "[i]n response to a growing awareness that visibility was rapidly deteriorating" in major national parks and wilderness areas ("Class I areas"). Chevron U.S.A., Inc. v. EPA, 658 F.2d 271, 272 (5th Cir. 1981). The section establishes a national goal of restoring natural visibility in such areas,[1] and expressly instructs EPA to issue regulations to "assure ... reasonable progress" toward meet-ing the national goal. 42 U.S.C. s 7491(a)(4). After examining the results of scientific studies, EPA concluded that such reasonable progress was not possible without a collective approach. The record compiled by EPA showed that visibility impairment in Class I areas is caused in large part by long-range transport of combined emissions from multiple sources.[2] Although it is practicable to trace emissions from an individual source into its surrounding region, and to model the transport of combined pollution from that region to a downwind Class I area,[3] it is not possible to trace emissions from an individual source directly to such a downwind area without great time and expense[4] - - and even then the results would be of uncertain reliability.[5] Citing the National Acade-my of Sciences' conclusion that a program focused "on deter-mining the contribution of individual emission sources to visibility impairment is doomed to failure,"[6] EPAadopted the group-BART approach that is at issue here.

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[1] Section 169A declares the national goal to be "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas." 42 U.S.C. s 7491(a)(1). As the court holds today, agency regulations that aim to accomplish these objectives "will of necessity aim to achieve a state of natural visibility." Op. at 16.

[2] See, e.g., Congressional Research Service, Regional Haze: EPA's Proposal to Improve Visibility in National Parks and Wilderness Areas 2 (1997) (J.A. at 242); National Academy of Sciences, National Research Council, Protecting Visibility in National Parks and Wilderness Areas 7-8, 196-99 (1993) (J.A. at 362, 456-57) [hereinafter "NAS Report"].

[3] See Regional Haze Regulations, 64 Fed. Reg. 35,714, 35,718 (July 1, 1999). The court does not dispute the reasonableness of, or support for, the latter proposition. Cf. Appalachian Power Co. v. EPA, 135 F.3d 791, 802 (D.C. Cir. 1998) (noting that "computer models are a useful and often essential tool for performing the Herculean labors Congress imposed on EPA in the Clean Air Act," and that "their scientific nature does not easily lend itself to judicial review" (internal quotation marks omitted)); id. at 814 ("[O]ur consideration of EPA's use of computer models proceeds with considerable deference to the agency's expertise.").

[4] See NAS Report at 240-41 (J.A. at 478) ("It would be extremely time-consuming and expensive to try to determine the percent contribution of individual sources to haze one source at a time."); Regional Haze Regulations, 64 Fed. Reg. at 35,740 ("[E]stablishing the contribution from one particular source to the problem of regional haze would require lengthy and expensive studies and pose substantial technical difficulties.").

[5] See NAS Report at 2 (J.A. at 359) ("During transport, the emissions from many sources mix together to form a uniform, widespread haze known as regional haze."); id. at 20 (J.A. at 368) ("[T]he extent to which [source-specific] techniques can be used in attributing visibility impairment is uncertain, as is their usefulness in estimating the effect that different control strategies might have on visibility."); id. at 25-26 (J.A. at 370-71) ("Efforts to decide whether a particular source is contributing to regional haze have thus far encountered grave obstacles. Studies designed to estimate the effect of a particular source on surrounding visibility are expensive, and the results can be uncertain and controversial."). To take just one example, "the efforts to trace the contribution of the Navajo Generating Station to haze in the Grand Canyon National Park took several years and cost millions of dollars without leading to quantitatively definitive answers." Id. at 7 (J.A. at 361).

[6]

EPA, Resp. to Pets. for Recons. of Regional Haze Rule 16 (Jan. 10, 2001) (J.A. at 17) (quoting NAS Report at 7 (J.A. at 361)); see also NAS Report at 240 (J.A. at 478) ("The committee doubts ... that such attributions could be the basis for a workable visibility protection program.").

My colleagues do not dispute that we must defer to EPA's expert opinion regarding the impracticability of tracing individual source emissions.[7] Rather, they conclude that not with-standing EPA's view of the facts, the industry petitioners are correct that the Haze Rule's group-BART provisions violate the plain meaning of the Clean Air Act by: (i) employing a group rather than source-by-source standard in determining the appropriate BART controls for a particular source, and (ii) constraining the authority of the states to make their own BART-related decisions. These two contentions are considered in Parts B and C below. Because I conclude that there is nothing in the Clean Air Act that bars the approach taken by EPA, and that to the contrary the Haze Rule rests on a reasonable interpretation of the statutory language, I would follow the Supreme Court's direction in Chevron and uphold the Rule.

B

As the court notes, the Haze Rule employs a group analysis in making two determinations required by the Clean Air Act: (i) whether a pollution-emitting source is subject to BART requirements at all, and (ii) what kind of BART controls should be placed on a subject source. The industry petitioners contend that the Clean Air Act prohibits the use of a group standard in making either of these determinations.

Under the Act, a source is subject to BART requirements, and hence a state implementation plan must require such a source to install BART controls, if it "emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any [Class I] area." CAA s 169A(b)(2)(A), 42 U.S.C. s 7491(b)(2)(A). Under the Haze Rule, a state must "find that a BART-eligible source is 'reasonably anticipated to cause or contribute' to regional haze if it can be shown that the source emits pollutants within a geographic area from which pollutants can be emitted and transported downwind to a Class I area." Regional Haze Regulations, 64 Fed. Reg. at 35,740. That is, a source is subject to BART requirements, without proof of that source's individual contribution to visibility impairment in a Class I area, as long as the source emits pollutants into an upwind area from which pollutants may be transported to a down-wind Class I area. Id.

The industry petitioners contend that CAA s 169A(b)(2) unambiguously provides that a source is subject to BART requirements only if a state can show the extent to which that particular source contributes to impairment in a Class I area. That section, however, requires states to impose BART controls on any source that "emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any [Class I] area." 42 U.S.C. s 7491(b)(2)(A) (emphasis added). Far from plainly compel-ling the petitioners' reading, the italicized words pile ambiguity upon ambiguity and virtually invite the reader to adopt the construction favored by EPA. See Merriam-Webster's Collegiate Dictionary 252 (10th ed. 1996) (defining "contribute" as "to give or supply in common with others," or "to give a part to a common ... store") (emphasis added); Central Ariz. Water Conservation Dist., 990 F.2d 1531, 1541 (9th Cir. 1993) ("The phrase 'may reasonably be anticipated' suggests that Congress did not intend to require EPA to show a precise relationship between a source's emissions and all or a specific fraction of the visibility impairment within a Class I area." (quoting with approval National Research Council, Haze in the Grand Canyon: An Evaluation of the Winter Haze Intensive Tracer Experiment 5 (1990))). If a source is one of several that emit pollutants into an upwind area, and if pollution from that area is transported downwind to a national park,[8] then it can hardly be unreasonable to conclude that the pollutants issued by the source "may reasonably be anticipated" to "contribute" to "any" impairment in the park.

My colleagues wisely do not accept the industry petitioners' contention that s 169A(b)(2) bars a collective determination of whether a source is subject to BART. (As discussed in Part C infra, they do conclude that EPA may not require the states to employ such a mode of analysis.) They do, however, accept the petitioners' contention that to determine the kind of BART controls that should be imposed on a subject source, a state must determine how much that particular source contributes to visual impairment in the downwind Class I area, Op. at 11, as well as the degree of improvement in visibility that would occur in the downwind area if that particular source installed such controls, id. at 10. The

[7] See Appalachian Power, 135 F.3d at 801-02 ("Our analysis is guided by the deference traditionally given to agency expertise, particularly when dealing with a statutory scheme as unwieldy and science-driven as the Clean Air Act."); see also Husqvarna AB v. EPA, 254 F.3d 195, 199 (D.C. Cir. 2001).

[8] Under the Haze Rule, the state must establish the first condition directly and the second through the application of computer modeling techniques. See Regional Haze Regulations, 64 Fed. Reg. at 35,740, 35,741; supra note 3.

Haze Rule, by contrast, provides that once a state has concluded that a particular source is subject to BART requirements, in determining the kind of BART controls to place on the source the state must consider the degree of improvement that would be achieved in the downwind area by imposing BART controls on all subject sources in the contributing upwind area. See 40 C.F.R. s 51.308(e)(1)(ii)(B); Regional Haze Regulations, 64 Fed. Reg. at 35,741.

The industry petitioners rest their contention that the statute unambiguously bars this collective assessment approach on s 169A(g)(2), which states:

> [I]n determining best available retrofit technology the State ... shall take into consideration [1] the costs of compliance, [2] the energy and nonair quality environ- mental 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.

42 U.S.C. s 7491(g)(2). According to both the industry petitioners and the court, this section requires the state to take into consideration each of the five listed factors on a source-by-source basis. Since the Haze Rule does require source-by-source consideration of the first four factors, see Regional Haze Regulations, 64 Fed. Reg. at 35,740-41; Op. at 9, the only question is whether such consideration is also required of the fifth factor: "the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."

There is nothing in the statutory language that requires a source-by-source application of the fifth factor. Section 169A(g)(2) requires an assessment of the degree of improvement that may reasonably be anticipated "from the use of such technology," but it does not say whether that improvement must be from the use of such technology by a single source or by all sources in the upwind area.[9] Although the court says that the statute does not permit any of the five factors to be treated differently from any of the others, the statute itself does not say so. Moreover, the first four factors are different in kind from the fifth: the first four all go to the cost of imposing controls on a particular source and permit a determination of the most cost-effective control technology for each such source. Regional Haze Regulations, 64 Fed. Reg. at 35,740-41. The fifth factor, by contrast, goes to the benefit to be derived from using the most cost-effective controls. In EPA's expert view, that benefit can best be determined by considering the total benefit that would accrue if each source in the upwind area used the kind of controls most cost-effective for that source.

The industry petitioners concede that s 169A(g)(2) does not require a state to undertake a cost-benefit analysis in deciding the type of controls to impose, or specify the weight to be accorded to any of the five factors.[10] All that is required is that the state "take into consideration" the five listed factors. 42 U.S.C. s 7491(g)(2). Because the statute does not specify how the state should take those factors into consideration, it does not bar EPA from employing a group rather than source-by-source mode of analysis in considering benefits. See Weyerhaeuser Co. v. Costle, 590 F.2d 1011, 1045 (D.C. Cir. 1978) (holding that where "Congress did not mandate any particular structure or weight" for the factors EPA is to consider, "it left EPA with discretion to decide how to account for the consideration factors, and how much weight to give each factor"); see also New York v. Reilly, 969 F.2d 1147, 1150 (D.C. Cir. 1992) (same).

Other related provisions of the Clean Air Act support EPA's reading of s 169A(g)(2) as permitting a region-wide assessment. Section 169A(a)(3) directs EPA to undertake a study to "identify the classes or categories of sources ... which, alone or in conjunction with other sources ..., may reasonably be anticipated to cause or contribute significantly to impairment of visibility," 42 U.S.C. s 7491(a)(3) (emphasis added), and s 169A(b)(1) directs that the regulations promulgated under s 169A take into account the recommendations of that study, 42 U.S.C. s 7491(b)(1). Similarly, s 169B(a)(1) instructs EPA to conduct research "to identify and evaluate sources and source regions of ... visibility impairment." 42 U.S.C. s 7492(a)(1) (emphasis added); see id. s

[9] See Regional Haze Regulations, 64 Fed. Reg. at 35,741 ("EPA interprets the language 'from the use of such technology' to refer to the application of BART level controls to all sources subject to BART.").

[10] Reply Br. for Industry Pet'rs at 8 ("Industry Petitioners agree ... that states are free to determine the weight and significance to be assigned to each of the CAA s 169A(g)(2) factors."); see Op. at 10; cf. American Textile Mfrs. Inst., Inc. v. Donovan, 452 U.S. 490, 510 (1981) ("When Congress has intended that an agency engage in cost-benefit analysis, it has clearly indicated such intent on the face of the statute."); Central Ariz., 990 F.2d at 1542 n.10 (holding that "Congress has not required 'cost-benefit' analysis in the [Clean Air] Act").

7492(a)(2). These provisions not only permit, but again appear to invite a group-BART approach.

The court states that "under EPA's take on the statute, it is ... entirely possible that a source may be forced to spend millions of dollars for new technology that will have no appreciable effect on the haze in any Class I area." Op. at 10. In accordance with the statute, however, EPA has structured the Haze Rule to avoid this result. The Rule creates an evidentiary presumption that, if a source emits pollution into an upwind region from which it can be shown that pollution is transported downwind to a Class I area, then it "may reasonably be anticipated" that the source "cause[s] or contribute[s] to" impairment in the Class I area--and hence that limiting the source's emissions will reduce that impairment.[11] But the presumption is not irrebuttable. To the contrary, the Haze Rule incorporates the exemption provision of s 169A(c)(1), which permits EPA to

> exempt any major stationary source from the [BART]requirement of subsection (b)(2)(A) of this section, upon his determination that such source does not or will not, by itself or in combination with other sources, emit any air pollutant which may reasonably be anticipated to cause or contribute to a significant impairment of visibility in any mandatory class I Federal area.

42 U.S.C. s 7491(c)(1); see also 40 C.F.R. ss 51.303, .308(e)(4). Hence, a source that emits pollution into a source region, but that can show that BART controls are unnecessary because its pollution does not contribute to a significant impairment of visibility in a Class I area, will not have to spend money installing BART controls.[12] All that the Haze Rule does is put the burden of proof on the polluter, rather than on the state. Moreover, the statute's limitation of the exemption to a source that does not by itself "or in combination with other sources" contribute to a significant impairment, 42 U.S.C. s 7491(c)(1), once again invites the collective-assessment approach taken by EPA.

Finally, one more provision of s 169A deserves repeat mention here. As discussed in Part A above, s 169A(a)(4) instructs EPA "to promulgate regulations to assure reason-able progress toward meeting the national goal" of restoring natural visibility conditions. 42 U.S.C. s 7491(a)(4). Yet EPA's findings indicate that it will not be possible "to assure reasonable progress" if the statutory interpretation announced today prevails: it is simply not practicable to deter-mine, as the court's interpretation requires, how much a particular "source is contributing to visual impairment in downwind Class I areas," or the degree of improvement in visibility in such areas "that would result from [a particular] source's installing and operating" BART controls. Op. at 11, 10; see supra notes 4, 5. Indeed, EPA explained that it "avoided inclusion of any approach in the regional haze rule that required the assessment of the visibility improvement attributed to an individual source because" the National Academy of Sciences had determined that such an approach was "doomed to failure." Resp. to Pets. for Recons. of Regional Haze Rule 16 (Jan. 10, 2001) (J.A. at 17) (quoting National Academy of Sciences, National Research Council, Protecting Visibility in National Parks and Wilderness Areas 7-8, 196-99 (1993) (J.A. at 362, 456-57)). We should not lightly assume that Congress enacted a statute that makes it impracticable to achieve the same statute's stated goal. There certainly is nothing in the language of the Clean Air Act that requires us to adopt such a self-defeating construction.

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[11] The court does not dispute the reasonableness of this presumption. See American Iron & Steel Inst. v. EPA, 115 F.3d 979, 1000 (D.C. Cir. 1997) (holding that it is reasonable for EPA to presume that if a pollutant is present in fish tissue at a level exceeding that set by regulation, then any facility "that contributes a pollutant to a body of water [in which the fish swims] ... has the reasonable potential to contribute to that exceedence"); see also Baltimore Gas & Elec. Co. v. Natural Res. Def. Council, Inc., 462 U.S. 87, 103 (1983) (holding that a reviewing court must be "at its most deferential" when the agency is "making predictions, within its area of special expertise, at the frontiers of science"); American Trucking Ass'ns, Inc. v. EPA, 175 F.3d 1027, 1055 (D.C. Cir. 1999) ("[W]e have expressly held that EPA's decision to adopt and set air quality standards need only be based on reasonable extrapolations from some reliable evidence." (internal quotation marks omitted)), rev'd on other grounds sub nom. Whitman v. American Trucking Ass'ns, Inc., 531 U.S. 457 (2001).

[12] The court correctly notes that under this exemption, it is EPA rather than the state that determines whether a source has made the required showing. EPA, however, does not rely on the exemption to answer the state-authority issue discussed in Part C below, but rather to counter the petitioners' claim that the Haze Rule fails to provide a source with the opportunity to demonstrate that it makes no appreciable contribution to visibility impairment in a Class I area. Br. for EPA at 29-30, 32.

C

The industry petitioners' second attack on the Haze Rule marches under the banner of states' rights, but in this case that banner is a false flag. The Rule gives states great leeway to make the BART determinations required by the Clean Air Act, reserving to EPA no more authority than Congress conferred upon the agency. Moreover, as discussed above, the industry petitioners' insistence that both EPA and the states are barred from using group-BART principles will impose an enormous unfunded mandate on the states--requiring them to engage in lengthy, expensive, and likely fruitless studies to trace pollutants from specific sources into specific Class I areas.[13] It is not surprising, therefore, that only a single state has enlisted under the petitioner's banner. Five others have filed briefs in support of EPA, while the balance remain silent.

The industry petitioners attack, as unlawfully constraining state authority, both the provision of the Haze Rule that concerns which sources are subject to BART requirements, and the provision that concerns the kind of BART controls that must be installed on subject sources. With respect to the former, the petitioners emphasize s 169A's declaration that "each major stationary source ... which, as determined by the State ... emits any air pollution which may reasonably be anticipated to cause or contribute to any impairment of visibility" in a Class I area, is subject to BART requirements. 42 U.S.C. s 7491(b)(2)(A) (emphasis added). With respect to the latter, they stress that s 169A requires that each subject source install "the best retrofit technology, as determined by the State," 42 U.S.C. s 7491(b)(2)(A), and that "in determining best available retrofit technology the State ... shall take into consideration" the five factors discussed in Part B above, id. s 7491(g)(2) (emphasis added). By directing the states to employ a group-BART analysis in making these determinations, the industry petitioners contend, and the court agrees, that EPA has unlawfully constrained the states' decision making authority. Op. at 11-13.

The Haze Rule, however, does not contravene the statutory commands italicized above. Under the Rule, it is the state and not EPA that determines which specific sources emit pollution that "may reasonably be anticipated to cause or contribute to" impairment, and hence are subject to BART requirements. All that EPA has done, as explained in Part B, is reasonably interpret that phrase to include sources that emit pollution into upwind regions from which pollution is transported to national parks. It is still the state that must determine both that the source emits covered pollutants, and that the region into which the source emits such pollutants is one from which emissions may reasonably be anticipated to be transported to downwind parks. See 40 C.F.R. s 51.308(e)(1)(ii); Regional Haze Regulations, 64 Fed. Reg. at 35,739-41; Br. for EPA at 43. Similarly, it is still the state that must take into consideration the five statutory factors and the state that must then determine the best available retrofit technology for a particular source. All that EPA has done, again as explained in Part B, is reasonably interpret the fifth of those factors to require the state to analyze the degree of anticipated improvement on a group basis. See Regional Haze Regulations, 64 Fed. Reg. at 35,741.

Moreover, the Clean Air Act expressly delegates to EPA the authority to make these kinds of judgments. As already noted, s 169A directs EPA to promulgate regulations to assure reasonable progress toward meeting the national goal of restoring natural visibility. 42 U.S.C. s 7491(a)(4). It further instructs that those regulations shall "provide guide-lines to the States ... on appropriate techniques and methods for implementing" the section's provisions, including the provisions governing which sources are subject to BART requirements and the kind of BART controls that should be imposed. Id. s 7491(b)(1). The section likewise directs EPA to "require each applicable implementation plan for a State ... to contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal" of restoring natural visibility. Id. s 7491(b)(2). Similarly, the next section of the Act, s 169B, orders EPA to "carry out [its] regulatory responsibilities" under s 169A by promulgating "criteria for measuring 'reasonable progress' toward the national goal." 42 U.S.C. s 7492(e)(1). These provisions give EPA ample authority to promulgate guidelines requiring states to use group-BART principles to determine both the sources that are subject to BART requirements and the kinds of controls those sources must install.

My colleagues contend that the Conference Report on the 1977 Clean Air Amendments reinforces their view that the Haze Rule impermissibly constrains state authority. Op. at 13. But that report is a weak reed upon which to rest a Chevron step one claim regarding the Act's plain meaning. As the court recounts, the report merely states that the conference "agreement clarifies that the State, rather than the Administrator, identifies the source that impairs

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[13] See supra notes 4, 5; Br. for Maine, et al. at 10 (protesting that to adopt the industry petitioners' interpretation of s 169A(g)(2) "would impose staggering and costly administrative burdens" on the states).

visibility," and that in determining the appropriate BART controls for such a source, "the state shall determine what constitutes 'best available retrofit technology' ... in establishing emission limitations on a source-by-source basis." H.R. Conf. Rep. No. 95-564, at 535 (1977). The report tells us nothing more about the referenced "agreement" than can be gleaned from these quotations, and the quotations themselves do little more than restate the statutory language. Moreover, as noted above, the Haze Rule is consistent with these quotations: under the Rule, it is the state rather than EPA that identifies the sources that impair visibility, and it is the state that determines the best available retrofit technology for each such individual source. All that the group-BART provisions of the Rule do is effectuate EPA's authority to "provide guidelines to the states" for making these determinations regarding particular sources. 42 U.S.C. s 7491(b)(1).[14]

As the Clean Air Act repeatedly declares, restoring natural visibility to national parks and wilderness areas is a "nation-al" goal. See id. s 7491(a)(1), (a)(4), (b)(2), (b)(2)(B); id. s 7492(e)(1). It is not surprising, therefore, that while the Act leaves many determinations regarding particular sources to the states, it grants EPA authority to establish national guidelines for the kind of analysis the states must employ in making those determinations.[15] Under the statute, those guidelines must "assure ... reasonable progress toward meeting the national goal" of restoring natural visibility. Id. s 7491(a)(4). Because EPA has reasonably determined that group-BART principles are necessary to provide such assurance, the provisions of the Haze Rule that incorporate those principles are a permissible exercise of the agency's delegated power.

D

In sum, there is nothing in the language, structure or history of the Clean Air Act that bars EPA from promulgating the group-BART provisions of its Haze Rule. To the contrary, those provisions represent "a reasonable interpretation of an ambiguous statute," and therefore must be given effect by this court. Christensen v. Harris County, 529 U.S. 576, 586 (2000) (citing Chevron, 467 U.S. at 842-844). Accordingly, I respectfully dissent from the court's decision to strike down those provisions.

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[14] The court states that the "agreement" referred to in the report was an agreement to reject the provisions of an earlier House bill. As there may have been many reasons for rejecting that bill, the "[r]ejection of [the] proposed legislation during the course of enactment provides a hazardous basis from which to determine legislative intent," GAO v. GAO Pers. Appeals Bd., 698 F.2d 517, 525 n.52 (D.C. Cir. 1983), and a particularly hazardous foundation for a Chevron step one claim. In any event, the most the court can divine regarding the content of the agreement is that it was to insert language clarifying that the states were to "deter-mine whether a source contributes to visibility impairment and, if so, what BART controls should be applied to that source." Op. at 13. As noted in the text, the Haze Rule leaves both determinations in the hands of the states.

[15] Cf. Appalachian Power Co. v. EPA, 249 F.3d 1032, 1047 (D.C. Cir. 2001) (holding that a state's development of its implementation plan under CAA s 110 is not "free of extrinsic legal constraints," including EPA's reasonable construction of CAA s 126).

ATTACHMENT H

September 8, 2003, Federal Register Notice – Proposed Consent Decree For BART Rule Promulgation Deadlines

Counsel, phone 202–502–8947, e-mail: *gordon.wagner@ferc.gov*.

Magalie R. Salas,

Secretary.

[FR Doc. 03–22720 Filed 9–5–03; 8:45 am]

BILLING CODE 6717–01–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–7555–1]

Proposed Consent Decree, Clean Air Act Citizen Suit

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of proposed Consent Decree; request for public comment.

SUMMARY: In accordance with section 113(g) of the Clean Air Act, as amended (''Act''), 42 U.S.C. 7413(g), notice is hereby given of a proposed Consent Decree. On August 15, 2003, Environmental Defense filed a complaint pursuant to section 304(a) of the Act, 42 U.S.C. 7604(a), alleging that the Environmental Protection Agency had failed to meet its mandatory duty to promulgate guidelines and requirements for Best Available Retrofit Technology (''BART'') for certain major stationary sources. *Environmental Defense* v. *Marianne Lamont Horinko,* No. 1:03CV01737 RMU (D.D.C.). On August 19, 2003, the United States Environmental Protection Agency lodged the proposed Consent Decree with the United States District Court for the District of Columbia Circuit. The proposed Consent Decree establishes a time frame for EPA to promulgate the BART regulations and guidelines.

DATES: Written comments on the Proposed Consent decree must be received by October 8, 2003.

ADDRESSES: Written comments should be sent to M. Lea Anderson, Air and Radiation Law Office (2344A), Office of General Counsel, U.S. Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460. Copies of the proposed Consent Decree are available from Phyllis J. Cochran, (202) 564–5566.

SUPPLEMENTARY INFORMATION: Environmental Defense alleges that EPA failed to promulgate BART regulations and guidelines by the Congressionally-enacted deadline.

Pursuant to sections 169A and 169B of the Clean Air Act, EPA promulgated regulations on July 1, 1999 to protect visibility in Federal Class I areas. 64 FR 35714 (''regional haze rule''). In addition, pursuant to section 169A(b), EPA proposed to promulgate guidelines for the implementation of the BART requirements of the regional haze rule on July 20, 2001, 66 FR 38108, but has not published final guidelines. The regional haze rule was challenged, and on May 24, 2002, the United States Court of Appeals for the District of Columbia Circuit (''D.C. Circuit'') vacated and remanded to EPA the BART provisions of the regional haze rule. *American Corn Growers Assoc.* v. *EPA*, 291 F.3d 1 (D.C. Cir. 2002).

Section 169B(e) of the CAA provides that EPA must carry out its regulatory responsibilities under section 169A of the Act to promulgate regulations to protect visibility by December 10, 1997.[1] These regulations must require each applicable implementation plan to contain measures to assure reasonable progress toward the national visibility goal, including requirements that certain major stationary sources procure, install, and operate BART. CAA section 169A(b)(2). The CAA also requires EPA to provide guidelines to the States on the implementation of the visibility program, including guidelines for the determination of BART emission limits for fossil-fuel fired generating plants with a total generating capacity in excess of 750 megawatts. CAA section 169A(b).

The Consent Decree provides that EPA will sign a notice of proposed rulemaking setting forth its proposed BART regulations and guidelines no later than April 15, 2004. It further provides that EPA will submit the notice of proposed rulemaking to the Office of Federal Register no later than five days following signature. The Decree also provides that EPA shall sign a final notice of rulemaking setting forth its BART regulations and guidelines no later than April 15, 2005, and that EPA will submit the notice of final rulemaking to the Office of Federal Register no later than five days following signature.

For a period of thirty (30) days following the date of publication of this notice, the Agency will receive written comments relating to the proposed Consent Decree from persons who were not named as parties or interveners to the litigation in question. EPA or the Department of Justice may withdraw or withhold consent to the proposed Consent Decree if the comments disclose facts or considerations that indicate that such consent is inappropriate, improper, inadequate, or inconsistent with the requirements of the Act. Unless EPA or the Department of Justice determine, following the comment period, that consent is inappropriate, the Consent Decree will be final.

[1] Section 169B(e)(1) of the CAA requires EPA to issue regional haze rules within 18 months of the receipt of the final report of the Grand Canyon Visibility Transport Commission. This report was received by EPA on June 10, 1996.

Dated: August 22, 2003.

Lisa K. Friedman,

Associate General Counsel.

[FR Doc. 03–22769 Filed 9–5–03; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–7554–7]

Control of Emissions From New Highway Vehicles and Engines

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of denial of petition for rulemaking.

SUMMARY: A group of organizations petitioned EPA to regulate emissions of carbon dioxide and other greenhouse gases from motor vehicles under the Clean Air Act. For the reasons set forth in this notice, EPA is denying the petition.

EFFECTIVE DATE: September 8, 2003.

ADDRESSES: Information relevant to this action is contained in Docket No. A–2000–04 at the EPA Docket Center, Public Reading Room, Room B102, EPA West Building, 1301 Constitution Avenue, NW., Washington, DC. Dockets may be inspected at this location from 8:30 a.m. to 4:30 p.m., Monday through Friday, except on Government holidays. You can reach the Air Docket by telephone at (202) 566–1742 and by facsimile at (202) 566–1741. You may be charged a reasonable fee for photocopying docket materials, as provided in 40 CFR part 2.

FOR FURTHER INFORMATION CONTACT: Chitra Kumar, Office of Air and Radiation, (202) 564–1389.

SUPPLEMENTARY INFORMATION:

I. Background

On October 20, 1999, the International Center for Technology Assessment (ICTA) and a number of other organizations[1] petitioned EPA to

[1] Alliance for Sustainable Communities, Applied Power Technologies, Bio Fuels America, California Solar Energy Industries Association, Clements Environmental Corporation, Environmental Advocates, Environmental and Energy Study Institute, Friends of the Earth, Full Circle Energy Project, Green Party of Rhode Island, Greenpeace USA, Network for Environmental and Economic Responsibility of the United Church of Christ, New Jersey Environmental Watch, New Mexico Solar

ATTACHMENT I

Model BART Cost Analysis - Induration Furnace NOx Emissions

<u>List of Tables</u>:

Table I-1: BART Screening Evaluation Summary: Straight Grate Induration - SCR

Model Source for Straight Grate Waste Gas Exhaust - NOx Emissions

General Information

Source Type	Straight Grate Waste Gas Exhaust
Pollutant:	NOx
Existing Pollution Control Equipment	None

Control Cost Summary

Control Technology	Control Eff %	Emissions T/y	Emission Reduction T/yr	Installed Capital Cost (SCR & Burner) $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton	Air Toxic's & AQRV's?	Energy Impacts?	Non-Air Env Impacts?
SCR on Ind Duct 1 yr catalyst life	**90%**	**309.7**	**278.7**	**2,397,513**	**1,103,603**	**3,959**	**NH3 Emissions**	**High**	**Catalyst Waste, Water**
2 yr catalyst life				**2,397,513**	**841,182**	**3,018**			
SCR Add on Control 2 yr catalyst life	**90%**	**309.7**	**278.7**	**3,720,873**	**2,622,367**	**9,408**	**NH3 Emissions**	**High**	**Catalyst Waste, Water**

Comments

Table I-2: BART Screening Evaluation Summary: Grate/Kiln Induration - SCR

Model Source for Grate/Kiln Waste Gas Exhaust - NOx Emissions

General Information

Source Type	Grate/Kiln Waste Gas Exhaust
Pollutant:	NOx
Existing Pollution Control Equipment	None

Control Cost Summary 50 PPM NO_x Case

Control Technology	Control Eff %	Emissions T/y	Emission Reduction T/yr	Installed Capital Cost (SCR & Burner) $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton	Air Toxic's & AQRV's?	Energy Impacts?	Non-Air Env Impacts?
SCR on Ind Duct 1 yr catalyst life	90%	387.1	348.4	4,181,322	2,036,612	5,846	NH3 Emissions	High	Catalyst Waste, Water
2 yr catalyst life				4,181,322	1,511,770	4,339			
SCR Add on Control 2 yr catalyst life	90%	387.1	348	5,755,072	4,878,940	14,004	NH3 Emissions	High	Catalyst Waste, Water

Comments

Control Cost Summary 175 PPM NO_x Case

Control Technology	Control Eff %	Emissions T/y	Emission Reduction T/yr	Installed Capital Cost (SCR & Burner) $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton	Air Toxic's & AQRV's?	Energy Impacts?	Non-Air Env Impacts?
SCR on Ind Duct 1 yr catalyst life	90%	1,354.9	1,219.4	4,181,322	2,169,600	1,779	NH3 Emissions	High	Catalyst Waste, Water
2 yr catalyst life				4,181,322	1,644,758	1,349			
SCR Add on Control 2 yr catalyst life	90%	1,354.9	1,219	5,755,072	5,011,928	4,110	NH3 Emissions	High	Catalyst Waste, Water

Comments

Table I-3: BART Screening Evaluation Summary: Straight Grate and Grate/Kiln Induration - LNB and UNLB

Model Source for Straight Grate and Grate/Kiln Waste Gas Exhaust - NOx Emissions
Preheat Induced Fuel-Gas Recirculation & Pre Heat Low NOx Burners

General Information

Source Type	Grate/Kiln Waste Gas Exhaust
	Straight Grate Waste Gas Exhaust
Pollutant:	NOx
Existing Pollution Control Equipment	None

Control Cost Summary Pre Heat Low NOx Burners

Control Technology	Control Eff %	Emissions T/y	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton	Air Toxic's & AQRV's?	Energy Impacts?	Non-Air Env Impacts?
Pre Heat IFGR Burners	50%	75.6	37.8	611,448	242,174	6,407	No	No	No
Pre Heat Low NOx Burners	25%	75.6	18.9	369,171	197,614	10,456	No	No	No

Comments

Table I-4a: Selective Catalytic Reduction - Straight Grate Induration - NOx 1 yr SCR Catalyst Life
BACT Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**1,210,590**
Instrumentation	10%	of control device cost (A)	121,059
MN Sales Taxes	6.5%	of control device cost (A)	78,688
Freight	5%	of control device cost (A)	60,530
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	18%		**1,470,867**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	117,669
Handling, erection	14%	of purchased equip cost (B)	205,921
Electrical	4%	of purchased equip cost (B)	58,835
Piping	4%	of purchased equip cost (B)	58,835
Insulation	1%	of purchased equip cost (B)	14,709
Painting	1%	of purchased equip cost (B)	14,709
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	30%		**470,677**
Total Direct Capital Cost			**1,941,544**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	147,087
Construction, field exp.	5%	of purchased equip cost (B)	73,543
Construction fee	10%	of purchased equip cost (B)	147,087
Startup	2%	of purchased equip cost (B)	29,417
Tests	1%	of purchased equip cost (B)	14,709
Contingencies	3%	of purchased equip cost (B)	44,126
Total Indirect Capital Costs	31%		**455,969**
Total Capital Investment (TCI)			**2,397,513**
Replacement Parts Cost & Installation Labor	506,448	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**1,891,065**
Total Annualized Capital Costs			**178,503**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.00	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	12,500
Supervisor	15%	of oper labor costs	1,875
Maintenance Labor	17.50	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	8,750
Maintenance Materials	100%	of maint labor costs	8,750
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 509 kW-hr, 8000 hr/yr, 90.0% of capacity	187,277
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Anhydrous Ammonia)	405.00	$/Ton, 32.1 lb/hr, 8000 hr/yr, Ammonia	47,755
Reagent #2 (Urea 50% Solution)	NA		-
Solid Waste Disposal	25.00	$/Ton, 50.7 ton/yr	1,268
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	156.72	$/ft3, 2,898.2 ft3, 1, 8000 hr/yr, 90.0% of capacity	541,899
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**810,074**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	19,125
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	23,975
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	23,975
Administration (2% total capital costs)	2%	of total capital costs (TCI)	47,950
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**293,529**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,103,603**
Pollutant Removed (tons/yr)			**279**
Cost per ton of NOx Removed			**3,959**

Notes & Assumptions

1 Equipment cost estimates obtained from cost curve created from Born Environmental SCR cost estimate dated, 2001
2 Used EPA guideline for catalytic oxidizers for cost analysis.
3 Increased factor for piping from 2% to 4% to cover ammonia piping. This is consistent with Steel Dynamics Analysis
4 Air blower power costs for catalyst bed pressure drop; ductwork pressure drop alreading part of plant design
5 Maks sure bed temp > 610 Deg F to min sulfate formation
6 Specify large passage size for catalyst bed. Include soot blowing mechanism & ID any cleaning practices needed
7 Make sure bed temp > 610 Deg F to min sulfate formation

Table I-4a: Selective Catalytic Reduction - Straight Grate Induration - NOx 1 yr SCR Catalyst Life (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost					
Catalyst Life	1	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	1.0700		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	156.72	\$/ft^3	50.7	1	50.7
Amount Required	2898.2	ft^3			
Catalyst Cost	506,448	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**506,448**				
Annualized Cost	**541,899**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	\$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at \$29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **506,448**

Design Flow	150,000	dscfm	170,455	scfm
	135	Temp Deg F		
	12%	% Moisture		
	188,865	acfm		

Operating Cost Calculations				Utilization Rate		90.0%	
				Annual hours of operation:		8,000	
Item	**Unit Cost \$**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.00	Hr	0.5	hr/8 hr shift	500	12,500	\$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	500	8,750	\$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	508.9	kW-hr	4,071,246	187,277	\$/kW-hr, 509 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	\$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	\$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	405	Ton	32.1	lb/hr	235,828	47,755	\$/Ton, 32.1 lb/hr, 8000 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	\$/Lb, 0.0 lb/hr, 8000 hr/yr, 50 wt% Urea Soln.
SW Disposal	25	Ton	50.7	ton/yr	51	1,268	\$/Ton, 50.7 ton/yr
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	\$/Ton, 80.000 ppm, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	156.72	ft^3	2898.2	ft^3	1	541,899	\$/ft3, 2,898.2 ft3, 1, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	\$/bag	0	bags	2	0	\$/\$/bag, 0.0 bags, 2, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
80.0	ppm	150,000	dscfm	NA	310	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**30.97**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**279**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	188,865	11.4	0.55	0.9	508.9	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.05	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**508.9**	

Ammonia	77.4	lb/hr NOx	0.370	lb NH3/lb NOx	32.1	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	77.4	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	114.5	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required

Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	188,865	
Vol #2	**2898.2**	ft3

Table I-4b: Selective Catalytic Reduction - Straight Grate Induration - NOx 2 yr SCR Catalyst Life
BACT Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Control Device (A)		**1,210,590**
Instrumentation	10% of control device cost (A)	121,059
MN Sales Taxes	6.5% of control device cost (A)	78,688
Freight	5% of control device cost (A)	60,530
Auxiliary equipment (not included in CD cost)	0% of control device cost (A)	0
Purchased Equipment Total (B)	18%	**1,470,867**
Installation		
Foundations & supports	8% of purchased equip cost (B)	117,669
Handling, erection	14% of purchased equip cost (B)	205,921
Electrical	4% of purchased equip cost (B)	58,835
Piping	4% of purchased equip cost (B)	58,835
Insulation	1% of purchased equip cost (B)	14,709
Painting	1% of purchased equip cost (B)	14,709
Expenses not covered by items listed above	0% of purchased equip cost (B)	0
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Installation Total	30%	**470,677**
Total Direct Capital Cost		**1,941,544**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	147,087
Construction, field exp.	5% of purchased equip cost (B)	73,543
Construction fee	10% of purchased equip cost (B)	147,087
Startup	2% of purchased equip cost (B)	29,417
Tests	1% of purchased equip cost (B)	14,709
Contingencies	3% of purchased equip cost (B)	44,126
Total Indirect Capital Costs	31%	**455,969**
Total Capital Investment (TCI)		**2,397,513**
Replacement Parts Cost & Installation Labor	506,448 Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**1,891,065**
Total Annualized Capital Costs		**178,503**
OPERATING COSTS		
Direct Operating Costs		
Operating Labor	25.00 $/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	12,500
Supervisor	15% of oper labor costs	1,875
Maintenance Labor	17.50 $/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	8,750
Maintenance Materials	100% of maint labor costs	8,750
Utilities, Reagents, Waste Management & Replacements		
Electricity	0.05 $/kW-hr, 509 kW-hr, 8000 hr/yr, 90.0% of capacity	187,277
Natural Gas (Fuel)	NA	-
Water	NA	-
Compressed Air	NA	-
Reagent #1(Anhydrous Ammonia)	405.00 $/Ton, 32.1 lb/hr, 8000 hr/yr, Ammonia	47,755
Reagent #2 (Urea 50% Solution)	NA	-
Solid Waste Disposal	25.00 $/Ton, 25.4 ton/yr	634
Hazardous Waste Disposal	NA	-
Wastewater Treatment	NA	-
Catalyst	156.72 $/ft3, 2,898.2 ft3, 2, 8000 hr/yr, 90.0% of capacity	280,112
Replacement Parts	NA	-
Total Annual Direct Operating Costs		**547,653**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	19,125
Property tax (1% total capital costs)	1% of total capital costs (TCI)	23,975
Insurance (1% total capital costs)	1% of total capital costs (TCI)	23,975
Administration (2% total capital costs)	2% of total capital costs (TCI)	47,950
Total Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**293,529**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**841,182**
Pollutant Removed (tons/yr)		**279**
Cost per ton of NOx Removed		**3,018**

Notes & Assumptions

1 Equipment cost estimates obtained from cost curve created from Born Environmental SCR cost estimate dated, 2001
2 Used EPA guideline for catalytic oxidizers for cost analysis.
3 Increased factor for piping from 2% to 4% to cover ammonia piping. This is consistent with Steel Dynamics Analysis
4 Air blower power costs for catalyst bed pressure drop; ductwork pressure drop alreading part of plant design
5 Maks sure bed temp > 610 Deg F to min sulfate formation
6 Specify large passage size for catalyst bed. Include soot blowing mechanism & ID any cleaning practices needed
7 Make sure bed temp > 610 Deg F to min sulfate formation

Table I-4b: Selective Catalytic Reduction - Straight Grate Induration - NOx 2 yr SCR Catalyst Life (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost					
Catalyst Life	2	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	0.5531		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	156.72	\$/ft^3	50.7	2	25.4
Amount Required	2898.2	ft^3			
Catalyst Cost	506,448	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**506,448**				
Annualized Cost	**280,112**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	\$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at \$29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **506,448**

Design Flow	150,000	dscfm	170,455	scfm
	135	Temp Deg F		
	12%	% Moisture		
	188,865	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,000**	
Item	**Unit Cost \$**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.00	Hr	0.5	hr/8 hr shift	500	12,500	\$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	500	8,750	\$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	508.9	kW-hr	4,071,246	187,277	\$/kW-hr, 509 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	\$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	\$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	405	Ton	32.1	lb/hr	235,828	47,755	\$/Ton, 32.1 lb/hr, 8000 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	\$/Lb, 0.0 lb/hr, 8000 hr/yr, 50 wt% Urea Soln.
SW Disposal	25	Ton	25.4	ton/yr	25	634	\$/Ton, 25.4 ton/yr
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	\$/Ton, 80.000 ppm, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	156.72	ft^3	2898.2	ft^3	2	280,112	\$/ft3, 2,898.2 ft3, 2, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	\$/bag	0	bags	2	0	\$/\$/bag, 0.0 bags, 2, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
80.0	ppm	150,000	dscfm	NA	310	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**30.97**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**279**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	188,865	11.4	0.55	0.9	508.9	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.05	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**508.9**	

Ammonia	77.4	lb/hr NOx	0.370	lb NH3/lb NOx	32.1	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	77.4	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	114.5	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required

Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	188,865	
Vol #2	**2898.2**	ft3

Table I-5a: Selective Catalytic Reduction - Grate/Kiln Induration - NOx (50-ppm) 1 yr SCR Catalyst Life
BACT Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Control Device (A)		**2,111,299**
Instrumentation	10% of control device cost (A)	211,130
MN Sales Taxes	6.5% of control device cost (A)	137,234
Freight	5% of control device cost (A)	105,565
Auxiliary equipment (not included in CD cost)	0% of control device cost (A)	0
Purchased Equipment Total (B)	18%	**2,565,228**
Installation		
Foundations & supports	8% of purchased equip cost (B)	205,218
Handling, erection	14% of purchased equip cost (B)	359,132
Electrical	4% of purchased equip cost (B)	102,609
Piping	4% of purchased equip cost (B)	102,609
Insulation	1% of purchased equip cost (B)	25,652
Painting	1% of purchased equip cost (B)	25,652
Expenses not covered by items listed above	0% of purchased equip cost (B)	0
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Installation Total	30%	**820,873**
Total Direct Capital Cost		**3,386,101**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	256,523
Construction, field exp.	5% of purchased equip cost (B)	128,261
Construction fee	10% of purchased equip cost (B)	256,523
Startup	2% of purchased equip cost (B)	51,305
Tests	1% of purchased equip cost (B)	25,652
Contingencies	3% of purchased equip cost (B)	76,957
Total Indirect Capital Costs	31%	**795,221**
Total Capital Investment (TCI)		**4,181,322**
Replacement Parts Cost & Installation Labor	1,012,895 Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**3,168,427**
Total Annualized Capital Costs		**299,077**
OPERATING COSTS		
Direct Operating Costs		
Operating Labor	25.00 $/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	12,500
Supervisor	15% of oper labor costs	1,875
Maintenance Labor	17.50 $/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	8,750
Maintenance Materials	100% of maint labor costs	8,750
Utilities, Reagents, Waste Management & Replacements		
Electricity	0.05 $/kW-hr, 1,018 kW-hr, 8000 hr/yr, 90.0% of capacity	374,554
Natural Gas (Fuel)	NA	-
Water	NA	-
Compressed Air	NA	-
Reagent #1(Anhydrous Ammonia)	405.00 $/Ton, 39.3 lb/hr, 8000 hr/yr, Ammonia	58,394
Reagent #2 (Urea 50% Solution)	NA	-
Solid Waste Disposal	25.00 $/Ton, 101.4 ton/yr	2,536
Hazardous Waste Disposal	NA	-
Wastewater Treatment	NA	-
Catalyst	156.72 $/ft3, 5,796.5 ft3, 1, 8000 hr/yr, 90.0% of capacity	1,083,798
Replacement Parts	NA	-
Total Annual Direct Operating Costs		**1,551,157**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	19,125
Property tax (1% total capital costs)	1% of total capital costs (TCI)	41,813
Insurance (1% total capital costs)	1% of total capital costs (TCI)	41,813
Administration (2% total capital costs)	2% of total capital costs (TCI)	83,626
Total Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**485,455**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**2,036,612**
Pollutant Removed (tons/yr)		**348**
Cost per ton of NOx Removed		**5,846**

Notes & Assumptions

1 Equipment cost estimates obtained from cost curve created from Born Environmental SCR cost estimate dated, 2001
2 Used EPA guideline for catalytic oxidizers for cost analysis.
3 Increased factor for piping from 2% to 4% to cover ammonia piping. This is consistent with Steel Dynamics Analysis
4 Air blower power costs for catalyst bed pressure drop; ductwork pressure drop alreading part of plant design
5 Maks sure bed temp > 610 Deg F to min sulfate formation
6 Specify large passage size for catalyst bed. Include soot blowing mechanism & ID any cleaning practices needed
7 Make sure bed temp > 610 Deg F to min sulfate formation

Table I-5a: Selective Catalytic Reduction - Grate/Kiln Induration - NOx (50-ppm) 1 yr SCR Catalyst Life (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost					
Catalyst Life	1	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	1.0700		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	156.72	\$/ft^3	101.4	1	101.4
Amount Required	5796.5	ft^3			
Catalyst Cost	1,012,895	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**1,012,895**				
Annualized Cost	**1,083,798**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **1,012,895**

Design Flow	300,000	dscfm	340,909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,000**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.00	Hr	0.5	hr/8 hr shift	500	12,500	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	500	8,750	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	1017.8	kW-hr	8,142,488	374,554	$/kW-hr, 1,018 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	405	Ton	39.3	lb/hr	288,366	58,394	$/Ton, 39.3 lb/hr, 8000 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	$/Lb, 0.0 lb/hr, 8000 hr/yr, 50 wt% Urea Soln.
SW Disposal	25	Ton	101.4	ton/yr	101	2,536	$/Ton, 101.4 ton/yr
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	$/Ton, 50.000 ppm, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	156.72	ft^3	5796.5	ft^3	1	1,083,798	$/ft3, 5,796.5 ft3, 1, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2	0	$/$/bag, 0.0 bags, 2, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation						
Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
50.0	ppm	300,000	dscfm	NA	387	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**38.71**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**348**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	377,730	11.4	0.55	0.9	1017.8	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.06	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**1017.8**	

Ammonia	96.8	lb/hr NOx	0.370	lb NH3/lb NOx	39.3	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	96.8	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	140.0	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required		
Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	377,730	
Vol #2	**5796.5**	ft3

Table I-5b: Selective Catalytic Reduction - Grate/Kiln Induration - NOx (50-ppm) 2 yr SCR Catalyst Life
BACT Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Control Device (A)		**2,111,299**
Instrumentation	10% of control device cost (A)	211,130
MN Sales Taxes	6.5% of control device cost (A)	137,234
Freight	5% of control device cost (A)	105,565
Auxiliary equipment (not included in CD cost)	0% of control device cost (A)	0
Purchased Equipment Total (B)	18%	**2,565,228**
Installation		
Foundations & supports	8% of purchased equip cost (B)	205,218
Handling, erection	14% of purchased equip cost (B)	359,132
Electrical	4% of purchased equip cost (B)	102,609
Piping	4% of purchased equip cost (B)	102,609
Insulation	1% of purchased equip cost (B)	25,652
Painting	1% of purchased equip cost (B)	25,652
Expenses not covered by items listed above	0% of purchased equip cost (B)	0
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Installation Total	30%	**820,873**
Total Direct Capital Cost		**3,386,101**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	256,523
Construction, field exp.	5% of purchased equip cost (B)	128,261
Construction fee	10% of purchased equip cost (B)	256,523
Startup	2% of purchased equip cost (B)	51,305
Tests	1% of purchased equip cost (B)	25,652
Contingencies	3% of purchased equip cost (B)	76,957
Total Indirect Capital Costs	31%	**795,221**
Total Capital Investment (TCI)		**4,181,322**
Replacement Parts Cost & Installation Labor	1,012,895 Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**3,168,427**
Total Annualized Capital Costs		**299,077**
OPERATING COSTS		
Direct Operating Costs		
Operating Labor	25.00 $/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	12,500
Supervisor	15% of oper labor costs	1,875
Maintenance Labor	17.50 $/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	8,750
Maintenance Materials	100% of maint labor costs	8,750
Utilities, Reagents, Waste Management & Replacements		
Electricity	0.05 $/kW-hr, 1,018 kW-hr, 8000 hr/yr, 90.0% of capacity	374,554
Natural Gas (Fuel)	NA	-
Water	NA	-
Compressed Air	NA	-
Reagent #1(Anhydrous Ammonia)	405.00 $/Ton, 39.3 lb/hr, 8000 hr/yr, Ammonia	58,394
Reagent #2 (Urea 50% Solution)	NA	-
Solid Waste Disposal	25.00 $/Ton, 50.7 ton/yr	1,268
Hazardous Waste Disposal	NA	-
Wastewater Treatment	NA	-
Catalyst	156.72 $/ft3, 5,796.5 ft3, 2, 8000 hr/yr, 90.0% of capacity	560,224
Replacement Parts	NA	-
Total Annual Direct Operating Costs		**1,026,315**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	19,125
Property tax (1% total capital costs)	1% of total capital costs (TCI)	41,813
Insurance (1% total capital costs)	1% of total capital costs (TCI)	41,813
Administration (2% total capital costs)	2% of total capital costs (TCI)	83,626
Total Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**485,455**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**1,511,770**
Pollutant Removed (tons/yr)		**348**
Cost per ton of NOx Removed		**4,339**

Notes & Assumptions

1 Equipment cost estimates obtained from cost curve created from Born Environmental SCR cost estimate dated, 2001
2 Used EPA guideline for catalytic oxidizers for cost analysis.
3 Increased factor for piping from 2% to 4% to cover ammonia piping. This is consistent with Steel Dynamics Analysis
4 Air blower power costs for catalyst bed pressure drop; ductwork pressure drop alreading part of plant design
5 Maks sure bed temp > 610 Deg F to min sulfate formation
6 Specify large passage size for catalyst bed. Include soot blowing mechanism & ID any cleaning practices needed
7 Make sure bed temp > 610 Deg F to min sulfate formation

Table I-5b: Selective Catalytic Reduction - Grate/Kiln Induration - NOx (50-ppm) 2 yr SCR Catalyst Life (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost					
Catalyst Life	2	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	0.5531		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	156.72	\$/ft^3	101.4	2	50.7
Amount Required	5796.5	ft^3			
Catalyst Cost	1,012,895	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**1,012,895**				
Annualized Cost	**560,224**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **1,012,895**

Design Flow	300,000	dscfm	340,909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations				**Utilization Rate**	**90.0%**		
				Annual hours of operation:	**8,000**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.00	Hr	0.5	hr/8 hr shift	500	12,500	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	500	8,750	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	1017.8	kW-hr	8,142,488	374,554	$/kW-hr, 1,018 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	405	Ton	39.3	lb/hr	288,366	58,394	$/Ton, 39.3 lb/hr, 8000 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	$/Lb, 0.0 lb/hr, 8000 hr/yr, 50 wt% Urea Soln.
SW Disposal	25	Ton	50.7	ton/yr	51	1,268	$/Ton, 50.7 ton/yr
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	$/Ton, 50.000 ppm, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	156.72	ft^3	5796.5	ft^3	2	560,224	$/ft3, 5,796.5 ft3, 2, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2	0	$/$/bag, 0.0 bags, 2, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation						
Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
50.0	ppm	300,000	dscfm	NA	387	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**38.71**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**348**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	377,730	11.4	0.55	0.9	1017.8	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.06	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**1017.8**	

Ammonia	96.8	lb/hr NOx	0.370	lb NH3/lb NOx	39.3	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	96.8	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	140.0	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required

Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	377,730	
Vol #2	**5796.5**	ft3

Table I-6a: Selective Catalytic Reduction - Grate/Kiln Induration - NOx (175-ppm) 1 yr SCR Catalyst Life
BACT Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**2,111,299**
Instrumentation	10%	of control device cost (A)	211,130
MN Sales Taxes	6.5%	of control device cost (A)	137,234
Freight	5%	of control device cost (A)	105,565
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	18%		**2,565,228**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	205,218
Handling, erection	14%	of purchased equip cost (B)	359,132
Electrical	4%	of purchased equip cost (B)	102,609
Piping	4%	of purchased equip cost (B)	102,609
Insulation	1%	of purchased equip cost (B)	25,652
Painting	1%	of purchased equip cost (B)	25,652
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	30%		**820,873**
Total Direct Capital Cost			**3,386,101**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	256,523
Construction, field exp.	5%	of purchased equip cost (B)	128,261
Construction fee	10%	of purchased equip cost (B)	256,523
Startup	2%	of purchased equip cost (B)	51,305
Tests	1%	of purchased equip cost (B)	25,652
Contingencies	3%	of purchased equip cost (B)	76,957
Total Indirect Capital Costs	31%		**795,221**
Total Capital Investment (TCI)			**4,181,322**
Replacement Parts Cost & Installation Labor	1,012,895	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**3,168,427**
Total Annualized Capital Costs			**299,077**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.00	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	12,500
Supervisor	15%	of oper labor costs	1,875
Maintenance Labor	17.50	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	8,750
Maintenance Materials	100%	of maint labor costs	8,750
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 1,018 kW-hr, 8000 hr/yr, 90.0% of capacity	374,555
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Anhydrous Ammonia)	405.00	$/Ton, 128.8 lb/hr, 8000 hr/yr, Ammonia	191,381
Reagent #2 (Urea 50% Solution)	NA		-
Solid Waste Disposal	25.00	$/Ton, 101.4 ton/yr	2,536
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	156.72	$/ft3, 5,796.5 ft3, 1, 8000 hr/yr, 90.0% of capacity	1,083,798
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**1,684,145**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	19,125
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	41,813
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	41,813
Administration (2% total capital costs)	2%	of total capital costs (TCI)	83,626
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**485,455**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,169,600**
Pollutant Removed (tons/yr)			**1,219**
Cost per ton of NOx Removed			**1,779**

Notes & Assumptions

1 Equipment cost estimates obtained from cost curve created from Born Environmental SCR cost estimate dated, 2001
2 Used EPA guideline for catalytic oxidizers for cost analysis.
3 Increased factor for piping from 2% to 4% to cover ammonia piping. This is consistent with Steel Dynamics Analysis
4 Air blower power costs for catalyst bed pressure drop; ductwork pressure drop alreading part of plant design
5 Maks sure bed temp > 610 Deg F to min sulfate formation
6 Specify large passage size for catalyst bed. Include soot blowing mechanism & ID any cleaning practices needed
7 Make sure bed temp > 610 Deg F to min sulfate formation

Table I-6a: Selective Catalytic Reduction - Grate/Kiln Induration - NOx (175-ppm) 1 yr SCR Catalyst Life (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost					
Catalyst Life	1	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	1.0700		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	156.72	\$/ft^3	101.4	1	101.4
Amount Required	5796.5	ft^3			
Catalyst Cost	1,012,895	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**1,012,895**				
Annualized Cost	**1,083,798**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	\$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at \$29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **1,012,895**

Design Flow	300,000	dscfm	340,909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,000**	
Item	**Unit Cost \$**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.00	Hr	0.5	hr/8 hr shift	500	12,500	\$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	500	8,750	\$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	1017.8	kW-hr	8,142,502	374,555	\$/kW-hr, 1,018 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	\$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	\$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	405	Ton	128.8	lb/hr	945,090	191,381	\$/Ton, 128.8 lb/hr, 8000 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	\$/Lb, 0.0 lb/hr, 8000 hr/yr, 50 wt% Urea Soln.
SW Disposal	25	Ton	101.4	ton/yr	101	2,536	\$/Ton, 101.4 ton/yr
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	\$/Ton, 175.000 ppm, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	156.72	ft^3	5796.5	ft^3	1	1,083,798	\$/ft3, 5,796.5 ft3, 1, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	\$/bag	0	bags	2	0	\$/\$/bag, 0.0 bags, 2, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
175.0	ppm	300,000	dscfm	NA	1,355	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**135.49**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1,219**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	377,730	11.4	0.55	0.9	1017.8	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.20	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**1017.8**	

Ammonia	338.7	lb/hr NOx	0.370	lb NH3/lb NOx	128.8	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	338.7	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	458.6	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required

Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	377,730	
Vol #2	**5796.5**	ft3

Table I-6a: Selective Catalytic Reduction - Grate/Kiln Induration - NOx (175-ppm) 2 yr SCR Catalyst Life
BACT Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**2,111,299**
Instrumentation	10%	of control device cost (A)	211,130
MN Sales Taxes	6.5%	of control device cost (A)	137,234
Freight	5%	of control device cost (A)	105,565
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	18%		**2,565,228**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	205,218
Handling, erection	14%	of purchased equip cost (B)	359,132
Electrical	4%	of purchased equip cost (B)	102,609
Piping	4%	of purchased equip cost (B)	102,609
Insulation	1%	of purchased equip cost (B)	25,652
Painting	1%	of purchased equip cost (B)	25,652
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	30%		**820,873**
Total Direct Capital Cost			**3,386,101**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	256,523
Construction, field exp.	5%	of purchased equip cost (B)	128,261
Construction fee	10%	of purchased equip cost (B)	256,523
Startup	2%	of purchased equip cost (B)	51,305
Tests	1%	of purchased equip cost (B)	25,652
Contingencies	3%	of purchased equip cost (B)	76,957
Total Indirect Capital Costs	31%		**795,221**
Total Capital Investment (TCI)			**4,181,322**
Replacement Parts Cost & Installation Labor	1,012,895	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**3,168,427**
Total Annualized Capital Costs			**299,077**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.00	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	12,500
Supervisor	15%	of oper labor costs	1,875
Maintenance Labor	17.50	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	8,750
Maintenance Materials	100%	of maint labor costs	8,750
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 1,018 kW-hr, 8000 hr/yr, 90.0% of capacity	374,555
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Anhydrous Ammonia)	405.00	$/Ton, 128.8 lb/hr, 8000 hr/yr, Ammonia	191,381
Reagent #2 (Urea 50% Solution)	NA		-
Solid Waste Disposal	25.00	$/Ton, 50.7 ton/yr	1,268
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	156.72	$/ft3, 5,796.5 ft3, 2, 8000 hr/yr, 90.0% of capacity	560,224
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**1,159,303**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	19,125
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	41,813
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	41,813
Administration (2% total capital costs)	2%	of total capital costs (TCI)	83,626
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**485,455**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,644,758**
Pollutant Removed (tons/yr)			**1,219**
Cost per ton of NOx Removed			**1,349**

Notes & Assumptions

1 Equipment cost estimates obtained from cost curve created from Born Environmental SCR cost estimate dated, 2001
2 Used EPA guideline for catalytic oxidizers for cost analysis.
3 Increased factor for piping from 2% to 4% to cover ammonia piping. This is consistent with Steel Dynamics Analysis
4 Air blower power costs for catalyst bed pressure drop; ductwork pressure drop alreading part of plant design
5 Maks sure bed temp > 610 Deg F to min sulfate formation
6 Specify large passage size for catalyst bed. Include soot blowing mechanism & ID any cleaning practices needed
7 Make sure bed temp > 610 Deg F to min sulfate formation

Table I-6a: Selective Catalytic Reduction - Grate/Kiln Induration - NOx (175-ppm) 2 yr SCR Catalyst Life (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost					
Catalyst Life	2	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	0.5531		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	156.72	\$/ft^3	101.4	2	50.7
Amount Required	5796.5	ft^3			
Catalyst Cost	1,012,895	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**1,012,895**				
Annualized Cost	**560,224**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	\$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at \$29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **1,012,895**

Design Flow	300,000	dscfm	340,909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations				**Utilization Rate**	**90.0%**		
				Annual hours of operation:	**8,000**		
Item	**Unit Cost \$**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.00	Hr	0.5	hr/8 hr shift	500	12,500	\$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	500	8,750	\$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	1017.8	kW-hr	8,142,502	374,555	\$/kW-hr, 1,018 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	\$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	\$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	405	Ton	128.8	lb/hr	945,090	191,381	\$/Ton, 128.8 lb/hr, 8000 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	\$/Lb, 0.0 lb/hr, 8000 hr/yr, 50 wt% Urea Soln.
SW Disposal	25	Ton	50.7	ton/yr	51	1,268	\$/Ton, 50.7 ton/yr
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	\$/Ton, 175.000 ppm, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	156.72	ft^3	5796.5	ft^3	2	560,224	\$/ft3, 5,796.5 ft3, 2, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	\$/bag	0	bags	2	0	\$/\$/bag, 0.0 bags, 2, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
175.0	ppm	300,000	dscfm	NA	1,355	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**135.49**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1,219**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	377,730	11.4	0.55	0.9	1017.8	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.20	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**1017.8**	

Ammonia	338.7	lb/hr NOx	0.370	lb NH3/lb NOx	128.8	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	338.7	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	458.6	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required

Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	377,730	
Vol #2	**5796.5**	ft3

Table I-7: Selective Non-Catalytic Reduction - Straight Grate Induration - NOx
BACT Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)		SNCR equipment + duct + grate bays + blower	**325,951**
Instrumentation	1%	of control device cost (A)	3,260
MN Sales Taxes	6.5%	of control device cost (A)	21,187
Freight	5%	of control device cost (A)	16,298
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	18%		**366,695**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	29,336
Handling, erection	14%	of purchased equip cost (B)	51,337
Electrical	4%	of purchased equip cost (B)	14,668
Piping	4%	of purchased equip cost (B)	14,668
Insulation	1%	of purchased equip cost (B)	3,667
Painting	1%	of purchased equip cost (B)	3,667
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	
Buildings, as required		Building extention to for additional grate sections	
Installation Total	30%		**117,342**
Total Direct Capital Cost			**484,037**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	36,669
Construction, field exp.	5%	of purchased equip cost (B)	18,335
Construction fee	10%	of purchased equip cost (B)	36,669
Startup	2%	of purchased equip cost (B)	7,334
Tests	1%	of purchased equip cost (B)	3,667
Contingencies	3%	of purchased equip cost (B)	11,001
Total Indirect Capital Costs	31%		**113,675**
Total Capital Investment (TCI)			**597,713**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**597,713**
Total Annualized Capital Costs			**56,420**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.00	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	12,500
Supervisor	15%	of oper labor costs	1,875
Maintenance Labor	17.50	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	8,750
Maintenance Materials	100%	of maint labor costs	8,750
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 223 kW-hr, 8000 hr/yr, 90.0% of capacity	82,139
Natural Gas (Fuel)	NA		-
Water	0.22	$/Mgal, 8.0 gpm, 8000 hr/yr, 90.0% of capacity	845
Compressed Air	0.27	$/Mscf, 14.0 scfm, 8000 hr/yr, 90.0% of capacity	1,814
Reagent #1(Anhydrous Ammonia)	NA		-
Reagent #2 (Urea 50% Solution)	0.09	$/Lb, 175.0 lb/hr, 8000 hr/yr, 50 wt% Urea Soln.	109,109
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**225,782**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	19,125
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	5,977
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	5,977
Administration (2% total capital costs)	2%	of total capital costs (TCI)	11,954
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**99,453**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**325,235**
Pollutant Removed (tons/yr)			**217**
Cost per ton of NOx Removed			**1,500**

Notes & Assumptions

1 Equipment cost estimated using 0.6 power factor in conjunction with SNCR cost estimate from Wheelabrator dated 2001.
2 Used EPA guideline for catalytic oxidizers for cost analysis.
3 Increased factor for piping from 2% to 4% to cover urea piping. This is consistent with Steel Dynamics Analysis
4 Air blower power costs for catalyst bed pressure drop; ductwork pressure drop alreading part of plant design
5 Equipment cost includes instrumentation. Reduced instrumentation factor from 10% to 1% to account for tie-ins to plant control system
6
7 Make sure bed temp > 610 Deg F to min sulfate formation

Table I-7: Selective Non-Catalytic Reduction - Straight Grate Induration - NOx (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	150,000	dscfm	170,455	scfm
	135	Temp Deg F		
	12%	% Moisture		
	188,865	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,000**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.00	Hr	0.5	hr/8 hr shift	500	12,500	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	500	8,750	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	223.2	kW-hr	1,785,637	82,139	$/kW-hr, 223 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	8	gpm	3,840	845	$/Mgal, 8.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	14.0	scfm	6,719,110	1,814	$/Mscf, 14.0 scfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	405	Ton	0.0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8000 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	175.0	lb/hr	1,283,630	109,109	$/Lb, 175.0 lb/hr, 8000 hr/yr, 50 wt% Urea Soln.
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 80.000 ppm, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/2-yr perioc	0	0	$/Ton, 80.000 ppm, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
80	ppm	150,000	dscfm	NA	310	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				70%	**92.91**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**217**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	188,865	5	0.55	0.9	223.2	OAQPS Cost Cont Manual 5th ed - Eq 3.37
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.05	50	0.8	0.9	0.00	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					223.2	

Ammonia	77.4	lb/hr NOx	0.370	lb NH3/lb NOx	32.1	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	77.4	lb/hr NOx	2.260	lb Urea Sol'n/lb NOx	175.0	lb/hr Urea Sol'n per vendor quote
Comp Air	0.08	scfm per lb/hr Urea			14.0	

Table I-8: Selective Non-Catalytic Reduction - Grate/Kiln Induration - NOx (50-ppm)
BACT Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)		SNCR equipment + duct + grate bays + blower	**494,049**
Instrumentation	1%	of control device cost (A)	4,940
MN Sales Taxes	6.5%	of control device cost (A)	32,113
Freight	5%	of control device cost (A)	24,702
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	18%		**555,805**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	44,464
Handling, erection	14%	of purchased equip cost (B)	77,813
Electrical	4%	of purchased equip cost (B)	22,232
Piping	4%	of purchased equip cost (B)	22,232
Insulation	1%	of purchased equip cost (B)	5,558
Painting	1%	of purchased equip cost (B)	5,558
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	
Buildings, as required		Building extention to for additional grate sections	
Installation Total	30%		**177,858**
Total Direct Capital Cost			**733,663**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	55,581
Construction, field exp.	5%	of purchased equip cost (B)	27,790
Construction fee	10%	of purchased equip cost (B)	55,581
Startup	2%	of purchased equip cost (B)	11,116
Tests	1%	of purchased equip cost (B)	5,558
Contingencies	3%	of purchased equip cost (B)	16,674
Total Indirect Capital Costs	31%		**172,300**
Total Capital Investment (TCI)			**905,962**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**905,962**
Total Annualized Capital Costs			**85,516**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.00	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	12,500
Supervisor	15%	of oper labor costs	1,875
Maintenance Labor	17.50	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	8,750
Maintenance Materials	100%	of maint labor costs	8,750
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 446 kW-hr, 8000 hr/yr, 90.0% of capacity	164,278
Natural Gas (Fuel)	NA		-
Water	0.22	$/Mgal, 8.0 gpm, 8000 hr/yr, 90.0% of capacity	845
Compressed Air	0.27	$/Mscf, 17.5 scfm, 8000 hr/yr, 90.0% of capacity	2,268
Reagent #1(Anhydrous Ammonia)	NA		-
Reagent #2 (Urea 50% Solution)	0.09	$/Lb, 218.7 lb/hr, 8000 hr/yr, 50 wt% Urea Soln.	136,386
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**335,652**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	19,125
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	9,060
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	9,060
Administration (2% total capital costs)	2%	of total capital costs (TCI)	18,119
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**140,880**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**476,532**
Pollutant Removed (tons/yr)			**271**
Cost per ton of NOx Removed			**1,759**

Notes & Assumptions

1 Equipment cost estimated using 0.6 power factor in conjunction with SNCR cost estimate from Wheelabrator dated 2001.
2 Used EPA guideline for catalytic oxidizers for cost analysis.
3 Increased factor for piping from 2% to 4% to cover urea piping. This is consistent with Steel Dynamics Analysis
4 Air blower power costs for catalyst bed pressure drop; ductwork pressure drop alreading part of plant design
5 Equipment cost includes instrumentation. Reduced instrumentation factor from 10% to 1% to account for tie-ins to plant control system
6
7 Make sure bed temp > 610 Deg F to min sulfate formation

Table I-8: Selective Non-Catalytic Reduction - Grate/Kiln Induration - NOx (50-ppm) (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	300,000	dscfm	340,909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,000**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.00	Hr	0.5	hr/8 hr shift	500	12,500	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	500	8,750	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	446.4	kW-hr	3,571,270	164,278	$/kW-hr, 446 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	8	gpm	3,840	845	$/Mgal, 8.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	17.49768	scfm	8,398,888	2,268	$/Mscf, 17.5 scfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	405	Ton	0.0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8000 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	218.7	lb/hr	1,604,538	136,386	$/Lb, 218.7 lb/hr, 8000 hr/yr, 50 wt% Urea Soln.
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 50.000 ppm, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/2-yr perioc	0	0	$/Ton, 50.000 ppm, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
50	ppm	300,000	dscfm	NA	387	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				70%	**116.14**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**271**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	377,730	5	0.55	0.9	446.4	OAQPS Cost Cont Manual 5th ed - Eq 3.37
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.06	50	0.8	0.9	0.00	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					446.4	

Ammonia	96.8	lb/hr NOx	0.370	lb NH3/lb NOx	39.3	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	96.8	lb/hr NOx	2.260	lb Urea Sol'n/lb NOx	218.7	lb/hr Urea Sol'n per vendor quote
Comp Air	0.08	scfm per lb/hr Urea			17.5	

Table I-9: Selective Non-Catalytic Reduction - Grate/Kiln Induration - NOx (175-ppm)
BACT Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)		SNCR equipment + duct + grate bays + blower	**494,049**
Instrumentation	1%	of control device cost (A)	4,940
MN Sales Taxes	6.5%	of control device cost (A)	32,113
Freight	5%	of control device cost (A)	24,702
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	18%		**555,805**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	44,464
Handling, erection	14%	of purchased equip cost (B)	77,813
Electrical	4%	of purchased equip cost (B)	22,232
Piping	4%	of purchased equip cost (B)	22,232
Insulation	1%	of purchased equip cost (B)	5,558
Painting	1%	of purchased equip cost (B)	5,558
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	
Buildings, as required		Building extention to for additional grate sections	
Installation Total	30%		**177,858**
Total Direct Capital Cost			**733,663**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	55,581
Construction, field exp.	5%	of purchased equip cost (B)	27,790
Construction fee	10%	of purchased equip cost (B)	55,581
Startup	2%	of purchased equip cost (B)	11,116
Tests	1%	of purchased equip cost (B)	5,558
Contingencies	3%	of purchased equip cost (B)	16,674
Total Indirect Capital Costs	31%		**172,300**
Total Capital Investment (TCI)			**905,962**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**905,962**
Total Annualized Capital Costs			**85,516**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.00	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	12,500
Supervisor	15%	of oper labor costs	1,875
Maintenance Labor	17.50	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	8,750
Maintenance Materials	100%	of maint labor costs	8,750
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 446 kW-hr, 8000 hr/yr, 90.0% of capacity	164,279
Natural Gas (Fuel)	NA		-
Water	0.22	$/Mgal, 8.0 gpm, 8000 hr/yr, 90.0% of capacity	845
Compressed Air	0.27	$/Mscf, 61.2 scfm, 8000 hr/yr, 90.0% of capacity	7,937
Reagent #1(Anhydrous Ammonia)	NA		-
Reagent #2 (Urea 50% Solution)	0.09	$/Lb, 765.5 lb/hr, 8000 hr/yr, 50 wt% Urea Soln.	477,350
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**682,286**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	19,125
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	9,060
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	9,060
Administration (2% total capital costs)	2%	of total capital costs (TCI)	18,119
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**140,880**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**823,166**
Pollutant Removed (tons/yr)			**948**
Cost per ton of NOx Removed			**868**

Notes & Assumptions

1 Equipment cost estimated using 0.6 power factor in conjunction with SNCR cost estimate from Wheelabrator dated 2001.
2 Used EPA guideline for catalytic oxidizers for cost analysis.
3 Increased factor for piping from 2% to 4% to cover urea piping. This is consistent with Steel Dynamics Analysis
4 Air blower power costs for catalyst bed pressure drop; ductwork pressure drop alreading part of plant design
5 Equipment cost includes instrumentation. Reduced instrumentation factor from 10% to 1% to account for tie-ins to plant control system
6
7 Make sure bed temp > 610 Deg F to min sulfate formation

Table I-9: Selective Non-Catalytic Reduction - Grate/Kiln Induration - NOx (175-ppm) (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	300,000	dscfm	340,909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,000**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.00	Hr	0.5	hr/8 hr shift	500	12,500	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	500	8,750	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	446.4	kW-hr	3,571,284	164,279	$/kW-hr, 446 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	8	gpm	3,840	845	$/Mgal, 8.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	61.24189	scfm	29,396,108	7,937	$/Mscf, 61.2 scfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	405	Ton	0.0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8000 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	765.5	lb/hr	5,615,881	477,350	$/Lb, 765.5 lb/hr, 8000 hr/yr, 50 wt% Urea Soln.
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 175.000 ppm, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/2-yr perioc	0	0	$/Ton, 175.000 ppm, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
175	ppm	300,000	dscfm	NA	1,355	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				70%	**406.47**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**948**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	377,730	5	0.55	0.9	446.4	OAQPS Cost Cont Manual 5th ed - Eq 3.37
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.20	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					446.4	

Ammonia	338.7	lb/hr NOx	0.370	lb NH3/lb NOx	128.8	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	338.7	lb/hr NOx	2.260	lb Urea Sol'n/lb NOx	765.5	lb/hr Urea Sol'n per vendor quote
Comp Air	0.08	scfm per lb/hr Urea			61.2	

Table I-10: Pre Heat Low NOx Burner - Straight Grate and Grate/Kiln Induration
BACT Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**142,857**
Instrumentation	10%	of control device cost (A)	14,286
MN Sales Taxes	3.0%	of control device cost (A)	4,286
Freight	5%	of control device cost (A)	7,143
Auxiliary equipment (not included in CD cost)	-	of control device cost (A) - See Notes	0
Purchased Equipment Total (B)	18%		**168,571**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	6,743
Handling, erection	50%	of purchased equip cost (B)	84,286
Electrical	8%	of purchased equip cost (B)	13,486
Piping	1%	of purchased equip cost (B)	1,686
Insulation	7%	of purchased equip cost (B)	11,800
Painting	4%	of purchased equip cost (B)	6,743
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	74%		**124,743**
Total Direct Capital Cost			**293,314**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	16,857
Construction, field exp.	20%	of purchased equip cost (B)	33,714
Construction fee	10%	of purchased equip cost (B)	16,857
Startup	1%	of purchased equip cost (B)	1,686
Tests	1%	of purchased equip cost (B)	1,686
Contingencies	3%	of purchased equip cost (B)	5,057
Total Indirect Capital Costs	45%		**75,857**
Total Capital Investment (TCI)			**369,171**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**369,171**
Total Annualized Capital Costs			**34,847**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.00	$/Hr, 2.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	50,000
Supervisor	15%	of oper labor costs	7,500
Maintenance Labor	17.50	$/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	17,500
Maintenance Materials	100%	of maint labor costs	17,500
Utilities, Reagents, Waste Management & Replacements			
Electricity	NA		-
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**92,500**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,500
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	3,692
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	3,692
Administration (2% total capital costs)	2%	of total capital costs (TCI)	7,383
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**105,114**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**197,614**
Pollutant Removed (tons/yr)[B]			**19**
Cost per ton of NOx Removed			**10,456**

Notes & Assumptions

1 1 At present, cost estimate is assumed to be 33% less than the cost of the Ultra Low NOx Burner bid by JZink, 2003.
2
3

Table I-10: Pre Heat Low NOx Burner - Straight Grate and Grate/Kiln Induration (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	150,000	dscfm	170,455	scfm
	135	Temp Deg F		
	12%	% Moisture		
	188,865	acfm		

Operating Cost Calculations				**Annual hours of operation:**		**8,000**	
				Utilization rate:		**90%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	2	hr/8 hr shift	2,000	50,000	$/Hr, 2.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.5	Hr	1	hr/8 hr shift	1,000	17,500	$/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	0.0	kW-hr	0	0	$/kW-hr, 0 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0	Mscf	100	Mscfm	48,000	0	$/Mscf, 100.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 50 wt% Urea Soln.
SW Disposal	0	Ton	0.857	ton/hr	6,857	0	$/Ton, 0.140 lb/mmbtu, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.140 lb/mmbtu, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.14	lb/mmbtu	150	mmbtu/hr	NA	**76**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				25%	**56.70**	
Emission Reduction T/yr					**19**	

	Flow acfm	D P in H2O	Blower Effi	Motor Eff	kW	
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37

Table I-11: Pre Heat Ultra Low NOx Burner - Straight Grate and Grate/Kiln Induration
BACT Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**190,000**
Instrumentation	10%	of control device cost (A)	19,000
MN Sales Taxes	3.0%	of control device cost (A)	5,700
Freight	5%	of control device cost (A)	9,500
Auxiliary equipment (not included in CD cost)	-	of control device cost (A)	55,000
Purchased Equipment Total (B)	18%		**279,200**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	11,168
Handling, erection	50%	of purchased equip cost (B)	139,600
Electrical	8%	of purchased equip cost (B)	22,336
Piping	1%	of purchased equip cost (B)	2,792
Insulation	7%	of purchased equip cost (B)	19,544
Painting	4%	of purchased equip cost (B)	11,168
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	74%		**206,608**
Total Direct Capital Cost			**485,808**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	27,920
Construction, field exp.	20%	of purchased equip cost (B)	55,840
Construction fee	10%	of purchased equip cost (B)	27,920
Startup	1%	of purchased equip cost (B)	2,792
Tests	1%	of purchased equip cost (B)	2,792
Contingencies	3%	of purchased equip cost (B)	8,376
Total Indirect Capital Costs	45%		**125,640**
Total Capital Investment (TCI)			**611,448**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**611,448**
Total Annualized Capital Costs			**57,716**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.00	$/Hr, 2.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	50,000
Supervisor	15%	of oper labor costs	7,500
Maintenance Labor	17.50	$/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	17,500
Maintenance Materials	100%	of maint labor costs	17,500
Utilities, Reagents, Waste Management & Replacements			
Electricity	NA		-
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	0.25	$/Mscf, 100.0 Mscfm, 8000 hr/yr, 90.0% of capacity	12,000
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**104,500**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,500
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	6,114
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	6,114
Administration (2% total capital costs)	2%	of total capital costs (TCI)	12,229
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**137,674**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**242,174**
Pollutant Removed (tons/yr)[B]			**37.8**
Cost per ton of NOx Removed			**6,407**

Notes & Assumptions

1 1 Equipment cost estimate provided by JZink. Additional cost of $55000 required for FD fan and auxillary equipment.

2 Assumed control efficiency is based on 3% excess air. Actual operating conditions are at 300-400% excess air.

3

Table I-11: Pre Heat Ultra Low NOx Burner - Straight Grate and Grate/Kiln Induration (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	150,000	dscfm	170,455	scfm
	135	Temp Deg F		
	12%	% Moisture		
	188,865	acfm		

Operating Cost Calculations — **Annual hours of operation: 8,000** — **Utilization rate: 90%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	2	hr/8 hr shift	2,000	50,000	$/Hr, 2.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.5	Hr	1	hr/8 hr shift	1,000	17,500	$/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	0.0	kW-hr	0	0	$/kW-hr, 0 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	100	Mscfm	48,000	12,000	$/Mscf, 100.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 50 wt% Urea Soln.
SW Disposal	0	Ton	0.857	ton/hr	6,857	0	$/Ton, 0.140 lb/mmbtu, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.140 lb/mmbtu, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.14	lb/mmbtu	150	mmbtu/hr	NA	**76**	

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				50%	**37.80**	
Emission Reduction T/yr					**37.80**	

	Flow acfm	D P in H2O	Blower Effi	Motor Eff	kW	
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37

Table I-12: Selective Catalytic Reduction - Straight Grate Induration with Duct Burner - NOx
BACT Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**1,210,590**
Instrumentation	10%	of control device cost (A)	121,059
MN Sales Taxes	6.5%	of control device cost (A)	78,688
Freight	5%	of control device cost (A)	60,530
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	18%		**1,470,867**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	117,669
Handling, erection	14%	of purchased equip cost (B)	205,921
Electrical	4%	of purchased equip cost (B)	58,835
Piping	4%	of purchased equip cost (B)	58,835
Insulation	1%	of purchased equip cost (B)	14,709
Painting	1%	of purchased equip cost (B)	14,709
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	30%		**470,677**
Total Direct Capital Cost			**1,941,544**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	147,087
Construction, field exp.	5%	of purchased equip cost (B)	73,543
Construction fee	10%	of purchased equip cost (B)	147,087
Startup	2%	of purchased equip cost (B)	29,417
Tests	1%	of purchased equip cost (B)	14,709
Contingencies	3%	of purchased equip cost (B)	44,126
Total Indirect Capital Costs	31%		**455,969**
Total Capital Investment (TCI)			**2,397,513**
Replacement Parts Cost & Installation Labor	506,448	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**1,891,065**
Total Annualized Capital Costs			**178,503**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.00	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	12,500
Supervisor	15%	of oper labor costs	1,875
Maintenance Labor	17.50	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	8,750
Maintenance Materials	100%	of maint labor costs	8,750
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 509 kW-hr, 8000 hr/yr, 90.0% of capacity	187,277
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Anhydrous Ammonia)	405.00	$/Ton, 32.1 lb/hr, 8000 hr/yr, Ammonia	47,755
Reagent #2 (Urea 50% Solution)	NA		-
Solid Waste Disposal	25.00	$/Ton, 25.4 ton/yr	634
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	156.72	$/ft3, 2,898.2 ft3, 2, 8000 hr/yr, 90.0% of capacity	280,112
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**547,653**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	19,125
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	23,975
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	23,975
Administration (2% total capital costs)	2%	of total capital costs (TCI)	47,950
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**293,529**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (SCR)			**841,182**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (Burner)			**1,781,185**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (SCR + Burner)			**2,622,367**
Pollutant Removed (tons/yr)			**279**
Cost per ton of NOx Removed			**9,408**

Notes & Assumptions

1 Equipment cost estimates obtained from cost curve created from Born Environmental SCR cost estimate dated, 2001
2 Used EPA guideline for catalytic oxidizers for cost analysis.
3 Increased factor for piping from 2% to 4% to cover ammonia piping. This is consistent with Steel Dynamics Analysis
4 Air blower power costs for catalyst bed pressure drop; ductwork pressure drop alreading part of plant design
5 Make sure bed temp > 610 Deg F to min sulfate formation
6 Specify large passage size for catalyst bed. Include soot blowing mechanism & ID any cleaning practices needed
7 Check for potential of any issue with ammonium bisulfate plugging downsteam equipment.

Table I-12: Selective Catalytic Reduction - Straight Grate Induration with Duct Burner - NOx (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost					
Catalyst Life	2	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	0.5531		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	156.72	\$/ft^3	50.7	2	25.4
Amount Required	2898.2	ft^3			
Catalyst Cost	506,448	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**506,448**				
Annualized Cost	**280,112**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **506,448**

Design Flow	150,000	dscfm	170,455	scfm
	135	Temp Deg F		
	12%	% Moisture		
	188,865	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,000**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.00	Hr	0.5	hr/8 hr shift	500	12,500	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	500	8,750	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	508.9	kW-hr	4,071,246	187,277	$/kW-hr, 509 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	405	Ton	32.1	lb/hr	235,828	47,755	$/Ton, 32.1 lb/hr, 8000 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	$/Lb, 0.0 lb/hr, 8000 hr/yr, 50 wt% Urea Soln.
SW Disposal	25	Ton	25.4	ton/yr	25	634	$/Ton, 25.4 ton/yr
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	$/Ton, 80.000 ppm, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	156.72	ft^3	2898.2	ft^3	2	280,112	$/ft3, 2,898.2 ft3, 2, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2	0	$/$/bag, 0.0 bags, 2, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
80.0	ppm	150,000	dscfm	NA	310	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**30.97**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**279**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	188,865	11.4	0.55	0.9	508.9	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.05	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**508.9**	

Ammonia	77.4	lb/hr NOx	0.370	lb NH3/lb NOx	32.1	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	77.4	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	114.5	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required

Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	188,865	
Vol #2	**2898.2**	ft3

Table I-12.1: Selective Catalytic Reduction - Duct Burner for Straight Grate Induration
BACT Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Control Device (A)		**676,513**
Instrumentation	10% of control device cost (A)	67,651
MN Sales Taxes	6.5% of control device cost (A)	43,973
Freight	5% of control device cost (A)	33,826
Auxiliary equipment (not included in CD cost)	0% of control device cost (A)	0
Purchased Equipment Total (B)	18%	**821,963**
Installation		
Foundations & supports	8% of purchased equip cost (B)	65,757
Handling, erection	14% of purchased equip cost (B)	115,075
Electrical	4% of purchased equip cost (B)	32,879
Piping	2% of purchased equip cost (B)	16,439
Insulation	1% of purchased equip cost (B)	8,220
Painting	1% of purchased equip cost (B)	8,220
Expenses not covered by items listed above	0% of purchased equip cost (B)	0
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Installation Total	30%	**246,589**
Total Direct Capital Cost		**1,068,552**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	82,196
Construction, field exp.	5% of purchased equip cost (B)	41,098
Construction fee	10% of purchased equip cost (B)	82,196
Startup	2% of purchased equip cost (B)	16,439
Tests	1% of purchased equip cost (B)	8,220
Contingencies	3% of purchased equip cost (B)	24,659
Total Indirect Capital Costs	31%	**254,809**
Total Capital Investment (TCI)		**1,323,360**
Replacement Parts Cost & Installation Labor	0 Capital Recovery Cost for Control System	**1,323,360**
Total Annualized Capital Costs		**124,916**
OPERATING COSTS		
Direct Operating Costs		
Operating Labor	25.00 $/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	12,500
Supervisor	15% of oper labor costs	1,875
Maintenance Labor	17.50 $/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	8,750
Maintenance Materials	100% of maint labor costs	8,750
Utilities, Reagents, Waste Management & Replacements		
Electricity	0.06 $/kW-hr, 223 kW-hr, 8000 hr/yr, 90.0% of capacity	105,352
Natural Gas (Fuel)	3.30 $/Mft3, 913 scfm, 8000 hr/yr, 90.0% of capacity	1,446,982
Water	NA	-
Compressed Air	NA	-
Reagent #1(Caustic)	NA	-
Reagent #2	NA	-
Solid Waste Disposal	NA	-
Hazardous Waste Disposal	NA	-
Wastewater Treatment	NA	-
Catalyst	NA	-
Replacement Parts	NA	-
Total Annual Direct Operating Costs		**1,584,210**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	19,125
Property tax (1% total capital costs)	1% of total capital costs (TCI)	13,234
Insurance (1% total capital costs)	1% of total capital costs (TCI)	13,234
Administration (2% total capital costs)	2% of total capital costs (TCI)	26,467
Total Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**196,975**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**1,781,185**
Pollutant Removed (tons/yr)[B]		-
Cost per ton of PM Removed		-

Notes & Assumptions

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Table I-12.1: Selective Catalytic Reduction - Duct Burner for Straight Grate Induration (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	150,000	dscfm	170,455	scfm
	135	Temp Deg F		
	12%	% Moisture		
	188,865	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,000**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	0.5	hr/8 hr shift	500	12,500	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	15%				NA	1875	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	500	8,750	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.059	kW-hr	223.2	kW-hr	1,785,632	105,352	$/kW-hr, 223 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	3.3	Mft^3	913	scfm	438,479	1,446,982	$/Mft3, 913 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 50 wt% Urea Soln.
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.000 , 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.000 , 8000 hr/yr
WW Treat	3.8	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation					
Uncontrolled Emission Rate					
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Emis Rate T/yr**	**Comments/Notes**
				1000	
Controlled Emission Rate					
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Emis Rate T/yr**	**Comments/Notes**
				500	
Emission Reduction T/yr				**500**	

	Flow acfm	D P in H2O	Blower Efl	Motor Eff	kW	
Blower	188,865	5	0.55	0.9	223.2	OAQPS Cost Cont Manual 5th ed - Eq 3.37

Table I-12.1: Selective Catalytic Reduction - Duct Burner for Straight Grate Induration (Continued)

Duct Burner Cost Estimate

	Input Numbers	
$\boxed{}$	Calculated Numbers	

Auxiliary Fuel Use Equation 3.19

T_{wi}	150	Deg F - Temperature of waste gas into heat recovery
T_{fi}	750	Deg F - Temperature of Flue gas into of heat recovery
T_{ref}	77	Deg F - Reference temperature for fuel combustion calculations
FER	70%	Factional Heat Recovery % Heat recovery section efficiency
T_{wo}	$\boxed{570}$	Deg F - Temperature of waste gas out of heat recovery
T_{fo}	$\boxed{330}$	Deg F - Temperature of flue gas into of heat recovery
$-h_{caf}$	21502	Btu/lb Heat of combustion auxiliary fuel (methane)
$-h_{wg}$	0	Btu/lb Heat of combustion waste gas
$C_{p\ wg}$	0.255	Btu/lb - Deg F Heat Capacity of waste gas (air)
p_{wg}	0.0739	lb/scf - Density of waste gas (air) at 77 Deg F
p_{af}	0.0408	lb/scf - Density of auxiliary fuel (methane) at 77 Deg F
Q_{wg}	170,455	scfm - Flow of waste gas
Q_{af}	$\boxed{913}$	scfm - Flow of auxiliary fuel

Flow Calculator

Design Flow	150,000	dscfm	170,455	scfm
	135	Temp Deg F		
	12%	% Moisture		
	188,865	acfm		

Year	2003	Inflation Rate	3.0%		
Cost Calculations	$\boxed{171,368}$	scfm Flue Gas		Cost in 1988 $'s	$\boxed{\$434,228}$
				Current Cost @ 3% inflation	$\boxed{\$676,513}$

Heat Rec %	A	B	
0	10,294	0.2355	Exponents per equation 3.24
0.3	13,149	0.2609	Exponents per equation 3.25
0.5	17,056	0.2502	Exponents per equation 3.26
0.7	21,342	0.2500	Exponents per equation 3.27

Reference: OAQPS Control Cost Manual 5th Ed Feb 1996 - Chapter 3 Thermal & Catalytic Incinerators (EPA 453/B-96-001)

Table I-13: Selective Catalytic Reduction - Grate/Kiln Induration with Duct Burner - NOx (50-ppm)
BACT Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**2,111,299**
Instrumentation	10%	of control device cost (A)	211,130
MN Sales Taxes	6.5%	of control device cost (A)	137,234
Freight	5%	of control device cost (A)	105,565
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	18%		**2,565,228**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	205,218
Handling, erection	14%	of purchased equip cost (B)	359,132
Electrical	4%	of purchased equip cost (B)	102,609
Piping	4%	of purchased equip cost (B)	102,609
Insulation	1%	of purchased equip cost (B)	25,652
Painting	1%	of purchased equip cost (B)	25,652
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	30%		**820,873**
Total Direct Capital Cost			**3,386,101**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	256,523
Construction, field exp.	5%	of purchased equip cost (B)	128,261
Construction fee	10%	of purchased equip cost (B)	256,523
Startup	2%	of purchased equip cost (B)	51,305
Tests	1%	of purchased equip cost (B)	25,652
Contingencies	3%	of purchased equip cost (B)	76,957
Total Indirect Capital Costs	31%		**795,221**
Total Capital Investment (TCI)			**4,181,322**
Replacement Parts Cost & Installation Labor	1,012,895	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**3,168,427**
Total Annualized Capital Costs			**299,077**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.00	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	12,500
Supervisor	15%	of oper labor costs	1,875
Maintenance Labor	17.50	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	8,750
Maintenance Materials	100%	of maint labor costs	8,750
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 1,018 kW-hr, 8000 hr/yr, 90.0% of capacity	374,554
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Anhydrous Ammonia)	405.00	$/Ton, 39.3 lb/hr, 8000 hr/yr, Ammonia	58,394
Reagent #2 (Urea 50% Solution)	NA		-
Solid Waste Disposal	25.00	$/Ton, 50.7 ton/yr	1,268
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	156.72	$/ft3, 5,796.5 ft3, 2, 8000 hr/yr, 90.0% of capacity	560,224
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**1,026,315**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	19,125
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	41,813
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	41,813
Administration (2% total capital costs)	2%	of total capital costs (TCI)	83,626
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**485,455**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (SCR)			**1,511,770**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (Burner)			**3,367,170**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (SCR + Burner)			**4,878,940**
Pollutant Removed (tons/yr)			**348**
Cost per ton of NOx Removed			**14,004**

Notes & Assumptions

1 Equipment cost estimates obtained from cost curve created from Born Environmental SCR cost estimate dated, 2001
2 Used EPA guideline for catalytic oxidizers for cost analysis.
3 Increased factor for piping from 2% to 4% to cover ammonia piping. This is consistent with Steel Dynamics Analysis
4 Air blower power costs for catalyst bed pressure drop; ductwork pressure drop alreading part of plant design
5 Make sure bed temp > 610 Deg F to min sulfate formation
6 Specify large passage size for catalyst bed. Include soot blowing mechanism & ID any cleaning practices needed
7 Check for potential of any issue with ammonium bisulfate plugging downsteam equipment.

Table I-13: Selective Catalytic Reduction - Grate/Kiln Induration with Duct Burner - NOx (50-ppm) (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost					
Catalyst Life	2	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft³		
CRF	0.5531		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	156.72	$/ft³	101.4	2	50.7
Amount Required	5796.5	ft³			
Catalyst Cost	1,012,895	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**1,012,895**				
Annualized Cost	**560,224**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **1,012,895**

Design Flow	300,000	dscfm	340,909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,000**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.00	Hr	0.5	hr/8 hr shift	500	12,500	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	500	8,750	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	1017.8	kW-hr	8,142,488	374,554	$/kW-hr, 1,018 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft³	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	405	Ton	39.3	lb/hr	288,366	58,394	$/Ton, 39.3 lb/hr, 8000 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	$/Lb, 0.0 lb/hr, 8000 hr/yr, 50 wt% Urea Soln.
SW Disposal	25	Ton	50.7	ton/yr	51	1,268	$/Ton, 50.7 ton/yr
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	$/Ton, 50.000 ppm, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	156.72	ft³	5796.5	ft³	2	560,224	$/ft3, 5,796.5 ft3, 2, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2	0	$/$/bag, 0.0 bags, 2, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
50.0	ppm	300,000	dscfm	NA	387	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**38.71**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**348**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	377,730	11.4	0.55	0.9	1017.8	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.06	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**1017.8**	

Ammonia	96.8	lb/hr NOx	0.370	lb NH3/lb NOx	39.3	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	96.8	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	140.0	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required		
Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	377,730	
Vol #2	**5796.5**	ft3

Table I-13.1: Selective Catalytic Reduction - Duct Burner for Grate/Kiln Induration - NOx
BACT Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**804,514**
Instrumentation	10%	of control device cost (A)	80,451
MN Sales Taxes	6.5%	of control device cost (A)	52,293
Freight	5%	of control device cost (A)	40,226
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	18%		**977,484**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	78,199
Handling, erection	14%	of purchased equip cost (B)	136,848
Electrical	4%	of purchased equip cost (B)	39,099
Piping	2%	of purchased equip cost (B)	19,550
Insulation	1%	of purchased equip cost (B)	9,775
Painting	1%	of purchased equip cost (B)	9,775
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	30%		**293,245**
Total Direct Capital Cost			**1,270,729**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	97,748
Construction, field exp.	5%	of purchased equip cost (B)	48,874
Construction fee	10%	of purchased equip cost (B)	97,748
Startup	2%	of purchased equip cost (B)	19,550
Tests	1%	of purchased equip cost (B)	9,775
Contingencies	3%	of purchased equip cost (B)	29,325
Total Indirect Capital Costs	31%		**303,020**
Total Capital Investment (TCI)			**1,573,749**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Cost for Control System	1,573,749
Total Annualized Capital Costs			**148,551**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.00	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	12,500
Supervisor	15%	of oper labor costs	1,875
Maintenance Labor	17.50	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	8,750
Maintenance Materials	100%	of maint labor costs	8,750
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.06	$/kW-hr, 446 kW-hr, 8000 hr/yr, 90.0% of capacity	210,705
Natural Gas (Fuel)	3.30	$/Mft3, 1,827 scfm, 8000 hr/yr, 90.0% of capacity	2,893,964
Water	NA		-
Compressed Air	NA		-
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**3,136,544**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	19,125
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	15,737
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	15,737
Administration (2% total capital costs)	2%	of total capital costs (TCI)	31,475
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**230,626**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**3,367,170**
Pollutant Removed (tons/yr)[B]			-
Cost per ton of PM Removed			-

Notes & Assumptions

1 1
2
3

Table I-13.1: Selective Catalytic Reduction - Duct Burner for Grate/Kiln Induration - NOx (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	300,000	dscfm	340,909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,000**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	0.5	hr/8 hr shift	500	12,500	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	15%				NA	1875	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	500	8,750	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.059	kW-hr	446.4	kW-hr	3,571,264	210,705	$/kW-hr, 446 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	3.3	Mft^3	1,827	scfm	876,959	2,893,964	$/Mft3, 1,827 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 50 wt% Urea Soln.
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.000 , 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.000 , 8000 hr/yr
WW Treat	3.8	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation					
Uncontrolled Emission Rate					
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Emis Rate T/yr**	**Comments/Notes**
				1000	
Controlled Emission Rate					
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Emis Rate T/yr**	**Comments/Notes**
				500	
Emission Reduction T/yr				**500**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	377,730	5	0.55	0.9	446.4	OAQPS Cost Cont Manual 5th ed - Eq 3.37

Table I-13.1: Selective Catalytic Reduction - Duct Burner for Grate/Kiln Induration - NOx (Continued)

Duct Burner Cost Estimate

Auxiliary Fuel Use Equation 3.19

Input Numbers
Calculated Numbers

T_{wi}	150	Deg F - Temperature of waste gas into heat recovery
T_{fi}	750	Deg F - Temperature of Flue gas into of heat recovery
T_{ref}	77	Deg F - Reference temperature for fuel combustion calculations
FER	70%	Factional Heat Recovery % Heat recovery section efficiency
T_{wo}	570	Deg F - Temperature of waste gas out of heat recovery
T_{fo}	330	Deg F - Temperature of flue gas into of heat recovery
$-h_{caf}$	21502	Btu/lb Heat of combustion auxiliary fuel (methane)
$-h_{wg}$	0	Btu/lb Heat of combustion waste gas
$C_{p\ wg}$	0.255	Btu/lb - Deg F Heat Capacity of waste gas (air)
p_{wg}	0.0739	lb/scf - Density of waste gas (air) at 77 Deg F
p_{af}	0.0408	lb/scf - Density of auxiliary fuel (methane) at 77 Deg F
Q_{wg}	340,909	scfm - Flow of waste gas
Q_{af}	1,827	scfm - Flow of auxiliary fuel

Flow Calculator

Design Flow	300,000	dscfm	340,909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Year 2003 Inflation Rate 3.0%

Cost Calculations 342,736 scfm Flue Gas Cost in 1988 $'s $516,387

Current Cost @ 3% inflation $804,514

Heat Rec %	A	B	
0	10,294	0.2355	Exponents per equation 3.24
0.3	13,149	0.2609	Exponents per equation 3.25
0.5	17,056	0.2502	Exponents per equation 3.26
0.7	21,342	0.2500	Exponents per equation 3.27

Reference: OAQPS Control Cost Manual 5th Ed Feb 1996 - Chapter 3 Thermal & Catalytic Incinerators (EPA 453/B-96-001)

Table I-14: Selective Catalytic Reduction - Grate/Kiln Induration with Duct Burner - NOx (175-ppm)
BACT Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**2,111,299**
Instrumentation	10%	of control device cost (A)	211,130
MN Sales Taxes	6.5%	of control device cost (A)	137,234
Freight	5%	of control device cost (A)	105,565
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	18%		**2,565,228**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	205,218
Handling, erection	14%	of purchased equip cost (B)	359,132
Electrical	4%	of purchased equip cost (B)	102,609
Piping	4%	of purchased equip cost (B)	102,609
Insulation	1%	of purchased equip cost (B)	25,652
Painting	1%	of purchased equip cost (B)	25,652
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	30%		**820,873**
Total Direct Capital Cost			**3,386,101**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	256,523
Construction, field exp.	5%	of purchased equip cost (B)	128,261
Construction fee	10%	of purchased equip cost (B)	256,523
Startup	2%	of purchased equip cost (B)	51,305
Tests	1%	of purchased equip cost (B)	25,652
Contingencies	3%	of purchased equip cost (B)	76,957
Total Indirect Capital Costs	31%		**795,221**
Total Capital Investment (TCI)			**4,181,322**
Replacement Parts Cost & Installation Labor	1,012,895	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**3,168,427**
Total Annualized Capital Costs			**299,077**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.00	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	12,500
Supervisor	15%	of oper labor costs	1,875
Maintenance Labor	17.50	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	8,750
Maintenance Materials	100%	of maint labor costs	8,750
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 1,018 kW-hr, 8000 hr/yr, 90.0% of capacity	374,555
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Anhydrous Ammonia)	405.00	$/Ton, 128.8 lb/hr, 8000 hr/yr, Ammonia	191,381
Reagent #2 (Urea 50% Solution)	NA		-
Solid Waste Disposal	25.00	$/Ton, 50.7 ton/yr	1,268
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	156.72	$/ft3, 5,796.5 ft3, 2, 8000 hr/yr, 90.0% of capacity	560,224
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**1,159,303**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	19,125
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	41,813
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	41,813
Administration (2% total capital costs)	2%	of total capital costs (TCI)	83,626
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**485,455**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (SCR)			**1,644,758**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (Burner)			**3,367,170**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (SCR + Burner)			**5,011,928**
Pollutant Removed (tons/yr)			**1,219**
Cost per ton of NOx Removed			**4,110**

Notes & Assumptions

1 Equipment cost estimates obtained from cost curve created from Born Environmental SCR cost estimate dated, 2001
2 Used EPA guideline for catalytic oxidizers for cost analysis.
3 Increased factor for piping from 2% to 4% to cover ammonia piping. This is consistent with Steel Dynamics Analysis
4 Air blower power costs for catalyst bed pressure drop; ductwork pressure drop already part of plant design
5 Make sure bed temp > 610 Deg F to min sulfate formation
6 Specify large passage size for catalyst bed. Include soot blowing mechanism & ID any cleaning practices needed
7 Check for potential of any issue with ammonium bisulfate plugging downsteam equipment.

Table I-14: Selective Catalytic Reduction - Grate/Kiln Induration with Duct Burner - NOx (175-ppm) (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost					
Catalyst Life	2	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	0.5531		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	156.72	\$/ft^3	101.4	2	50.7
Amount Required	5796.5	ft^3			
Catalyst Cost	1,012,895	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**1,012,895**				
Annualized Cost	**560,224**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	\$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at \$29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **1,012,895**

Design Flow	300,000	dscfm	340,909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,000**	
Item	**Unit Cost \$**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.00	Hr	0.5	hr/8 hr shift	500	12,500	\$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	500	8,750	\$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	1017.8	kW-hr	8,142,502	374,555	\$/kW-hr, 1,018 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	\$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	\$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	405	Ton	128.8	lb/hr	945,090	191,381	\$/Ton, 128.8 lb/hr, 8000 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	\$/Lb, 0.0 lb/hr, 8000 hr/yr, 50 wt% Urea Soln.
SW Disposal	25	Ton	50.7	ton/yr	51	1,268	\$/Ton, 50.7 ton/yr
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	\$/Ton, 175.000 ppm, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	156.72	ft^3	5796.5	ft^3	2	560,224	\$/ft3, 5,796.5 ft3, 2, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	\$/bag	0	bags	2	0	\$/\$/bag, 0.0 bags, 2, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
175.0	ppm	300,000	dscfm	NA	1,355	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**135.49**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1,219**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	377,730	11.4	0.55	0.9	1017.8	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.20	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**1017.8**	

Ammonia	338.7	lb/hr NOx	0.370	lb NH3/lb NOx	128.8	lb/hr NH3; includes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	338.7	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	458.6	lb/hr Urea Sol'n; includes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required

Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	377,730	
Vol #2	**5796.5**	ft3

Table I-14.1: Selective Catalytic Reduction - Duct Burner for Grate/Kiln Induration - NOx
BACT Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**804,514**
Instrumentation	10%	of control device cost (A)	80,451
MN Sales Taxes	6.5%	of control device cost (A)	52,293
Freight	5%	of control device cost (A)	40,226
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	18%		**977,484**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	78,199
Handling, erection	14%	of purchased equip cost (B)	136,848
Electrical	4%	of purchased equip cost (B)	39,099
Piping	2%	of purchased equip cost (B)	19,550
Insulation	1%	of purchased equip cost (B)	9,775
Painting	1%	of purchased equip cost (B)	9,775
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	30%		**293,245**
Total Direct Capital Cost			**1,270,729**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	97,748
Construction, field exp.	5%	of purchased equip cost (B)	48,874
Construction fee	10%	of purchased equip cost (B)	97,748
Startup	2%	of purchased equip cost (B)	19,550
Tests	1%	of purchased equip cost (B)	9,775
Contingencies	3%	of purchased equip cost (B)	29,325
Total Indirect Capital Costs	31%		**303,020**
Total Capital Investment (TCI)			**1,573,749**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Cost for Control System	1,573,749
Total Annualized Capital Costs			**148,551**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.00	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	12,500
Supervisor	15%	of oper labor costs	1,875
Maintenance Labor	17.50	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	8,750
Maintenance Materials	100%	of maint labor costs	8,750
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.06	$/kW-hr, 446 kW-hr, 8000 hr/yr, 90.0% of capacity	210,705
Natural Gas (Fuel)	3.30	$/Mft3, 1,827 scfm, 8000 hr/yr, 90.0% of capacity	2,893,964
Water	NA		-
Compressed Air	NA		-
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**3,136,544**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	19,125
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	15,737
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	15,737
Administration (2% total capital costs)	2%	of total capital costs (TCI)	31,475
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**230,626**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**3,367,170**
Pollutant Removed (tons/yr) [B]			-
Cost per ton of PM Removed			-

Notes & Assumptions

1
2

Table I-14.1: Selective Catalytic Reduction - Duct Burner for Grate/Kiln Induration - NOx (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	300,000	dscfm	340,909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,000**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	0.5	hr/8 hr shift	500	12,500	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	15%				NA	1875	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	500	8,750	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.059	kW-hr	446.4	kW-hr	3,571,264	210,705	$/kW-hr, 446 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	3.3	Mft^3	1,827	scfm	876,959	2,893,964	$/Mft3, 1,827 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 50 wt% Urea Soln.
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.000 , 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.000 , 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation					
Uncontrolled Emission Rate					
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Emis Rate T/yr**	**Comments/Notes**
				1000	
Controlled Emission Rate					
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Emis Rate T/yr**	**Comments/Notes**
				500	
Emission Reduction T/yr				**500**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	377,730	5	0.55	0.9	446.4	OAQPS Cost Cont Manual 5th ed - Eq 3.37

Table I-14.1: Selective Catalytic Reduction - Duct Burner for Grate/Kiln Induration - NOx (Continued)

Duct Burner Cost Estimate

Auxiliary Fuel Use Equation 3.19

Input Numbers
[ ] Calculated Numbers

T_{wi}	150	Deg F - Temperature of waste gas into heat recovery
T_{fi}	750	Deg F - Temperature of Flue gas into of heat recovery
T_{ref}	77	Deg F - Reference temperature for fuel combustion calculations
FER	70%	Factional Heat Recovery % Heat recovery section efficiency
T_{wo}	570	Deg F - Temperature of waste gas out of heat recovery
T_{fo}	330	Deg F - Temperature of flue gas into of heat recovery
$-h_{caf}$	21502	Btu/lb Heat of combustion auxiliary fuel (methane)
$-h_{wg}$	0	Btu/lb Heat of combustion waste gas
$C_{p\ wg}$	0.255	Btu/lb - Deg F Heat Capacity of waste gas (air)
p_{wg}	0.0739	lb/scf - Density of waste gas (air) at 77 Deg F
p_{af}	0.0408	lb/scf - Density of auxiliary fuel (methane) at 77 Deg F
Q_{wg}	340,909	scfm - Flow of waste gas
Q_{af}	1,827	scfm - Flow of auxiliary fuel

Flow Calculator

Design Flow	300,000	dscfm	340,909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Year 2003 Inflation Rate 3.0%

Cost Calculations 342,736 scfm Flue Gas Cost in 1988 $'s $516,387

Current Cost @ 3% inflation $804,514

Heat Rec %	A	B	
0	10,294	0.2355	Exponents per equation 3.24
0.3	13,149	0.2609	Exponents per equation 3.25
0.5	17,056	0.2502	Exponents per equation 3.26
0.7	21,342	0.2500	Exponents per equation 3.27

Reference: OAQPS Control Cost Manual 5th Ed Feb 1996 - Chapter 3 Thermal & Catalytic Incinerators (EPA 453/B-96-001)

Table I-15: LTO Scrubber - Grate/Kiln Induration - NOx (50-ppm)
BACT Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**9,464,103**
Instrumentation	1%	of control device cost (A)	94,641
MN Sales Taxes	6.5%	of control device cost (A)	615,167
Freight	5%	of control device cost (A)	473,205
Auxiliary equipment (not included in CD cost)	5.0%	of control device cost (A)	473,205
Purchased Equipment Total (B)	18%		**11,120,321**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	1,334,439
Handling, erection	40%	of purchased equip cost (B)	4,448,128
Electrical	1%	of purchased equip cost (B)	111,203
Piping	30%	of purchased equip cost (B)	3,336,096
Insulation	1%	of purchased equip cost (B)	111,203
Painting	1%	of purchased equip cost (B)	111,203
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	85%		**9,452,273**
Total Direct Capital Cost			**20,572,594**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	1,112,032
Construction, field exp.	10%	of purchased equip cost (B)	1,112,032
Construction fee	10%	of purchased equip cost (B)	1,112,032
Startup	1%	of purchased equip cost (B)	111,203
Tests	1%	of purchased equip cost (B)	111,203
Contingencies	3%	of purchased equip cost (B)	333,610
Total Indirect Capital Costs	35%		**3,892,112**
Total Capital Investment (TCI) + Technology Fee of $1,012,000			**25,476,706**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Cost for Control System	**25,476,706**
Total Annualized Capital Costs			**2,404,821**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.00	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr	12,500
Supervisor	15%	of oper labor costs	1,875
Maintenance Labor	17.50	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr	8,750
Maintenance Materials	100%	of maint labor costs	8,750
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.0460	$/kW-hr, 1,052.0 kW-hr, 8000 hr/yr, 90.0% of capacity	387,136
Natural Gas (Fuel)	NA		-
Water	0.22	$/Mgal, 180.0 gpm, 8000 hr/yr, 90.0% of capacity	19,008
Compressed Air	NA		-
Reagent #1(Oxygen)	1.2	$/Mscf, 1.9 mscfh, 8000 hr/yr	16,272
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	5.35	$/Mgal, 180.0 gpm, 8000 hr/yr, 90.0% of capacity	462,240
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**916,531**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	19,125
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	254,767
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	254,767
Administration (2% total capital costs)	2%	of total capital costs (TCI)	509,534
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**3,443,014**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,359,545**
Pollutant Removed (tons/yr)			**348**
Cost per ton of NOx Removed			**12,513**

Notes & Assumptions

1 Aux equip & supports estimated at 5%. Vendor is more complete than other scrubber bids which had a 15% factor for auxiliary equipment.
2 Make up- water & wastewater blowdown rates = 20% of circulating rate per vendor
3 Equipment cost estimate from vendor dated 7/2/2001
4 Oxygen use and electric power use for LTO skid provided by vendor
5 Equipment cost includes instrumentation. Reduced instrumentation factor from 10% to 1% to account for tie-ins to plant control system
6 Used biological treatment cost for wastewater to address treatment for nitrates
7
8

Table I-15: LTO Scrubber - Grate/Kiln Induration - NOx (50-ppm) (Continued)

Capital Recovery Factors			
Primary Installation			
Interest Rate	7.0%		
Equipment Life	20	years	Equipment Life per Vendor
CRF	0.0944		

Catalyst Replacement Cost		
Catalyst Life		years
CRF		
Catalyst cost per unit		$/ft^3
Amount Required		ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life		
CRF		
Rep part cost per unit		$ each
Amount Required		Number
Total Rep Parts Cost		Cost adjusted for freight & sales tax
Installation Labor		10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Operating Cost Calculations					**Utilization Rate**		**90.0%**	
					Annual hours of operation:		**8,000**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**	
Op Labor	25	Hr	0.5	hr/8 hr shift	500	12,500	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr	
Supervisor	NA				NA	NA	Calc'd as % of labor costs	
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	500	8,750	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr	
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs	
Utilities, Reagents, Waste Management & Replacements								
Electricity	0.046	kW-hr	1052	kW-hr	8,416,000	387,136	$/kW-hr, 1,052.0 kW-hr, 8000 hr/yr, 90.0% of capacity	
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity	
Water	0.22	Mgal	180.0	gpm	86,400	19,008	$/Mgal, 180.0 gpm, 8000 hr/yr, 90.0% of capacity	
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity	
Reagent #1(Oxygen)	1.2	Mscf	2	mscfh	13,560	16,272	$/Mscf, 1.9 mscfh, 8000 hr/yr	
Reagent #2	0	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, Lime	
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.0 ton/hr, 50.00 ppm, 8000 hr/yr. 90.0% of capacity	
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.0 ton/hr, 50.00 ppm, 8000 hr/yr. 90.0% of capacity	
WW Treat	5.35	Mgal	180.0	gpm	86,400	462,240	$/Mgal, 180.0 gpm, 8000 hr/yr, 90.0% of capacity	
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity	
Rep Parts	0	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity	

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation					
Uncontrolled Emission Rate					
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Emis Rate T/yr**	**Comments/Notes**
50.0	ppm	300,000	dscfm	387	
Controlled Emission Rate					
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Emis Rate T/yr**	**Comments/Notes**
90%	Pct Red			**39**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr				**348**	

	Flow acfm	△ P in H2O	Blower Eff	Motor Eff	kW	
Blower						OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	△ P ft H2O	Pump Eff	Motor Eff		
Circ Pump	900					Estimated from Vendor Data (gpm= mscfh gas * 3)
H2O WW Disch	180					Water Makeup Rate/WW Disch = 20% of circulating water rate
LTO Skid Electric Use					1,052	Estimated from Vendor Data
Oxygen Use	1.9	mscfh				Estimated from Vendor Data

Table I-16: LTO Scrubber - Grate/Kiln Induration - NOx (175-ppm)
BACT Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**16,464,811**
Instrumentation	1%	of control device cost (A)	164,648
MN Sales Taxes	6.5%	of control device cost (A)	1,070,213
Freight	5%	of control device cost (A)	823,241
Auxiliary equipment (not included in CD cost)	5.0%	of control device cost (A)	823,241
Purchased Equipment Total (B)	18%		**19,346,153**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	2,321,538
Handling, erection	40%	of purchased equip cost (B)	7,738,461
Electrical	1%	of purchased equip cost (B)	193,462
Piping	30%	of purchased equip cost (B)	5,803,846
Insulation	1%	of purchased equip cost (B)	193,462
Painting	1%	of purchased equip cost (B)	193,462
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	85%		**16,444,230**
Total Direct Capital Cost			**35,790,383**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	1,934,615
Construction, field exp.	10%	of purchased equip cost (B)	1,934,615
Construction fee	10%	of purchased equip cost (B)	1,934,615
Startup	1%	of purchased equip cost (B)	193,462
Tests	1%	of purchased equip cost (B)	193,462
Contingencies	3%	of purchased equip cost (B)	580,385
Total Indirect Capital Costs	35%		**6,771,154**
Total Capital Investment (TCI) + Technology Fee of $1,012,000			**43,573,536**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Cost for Control System	**43,573,536**
Total Annualized Capital Costs			**4,113,034**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.00	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr	12,500
Supervisor	15%	of oper labor costs	1,875
Maintenance Labor	17.50	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr	8,750
Maintenance Materials	100%	of maint labor costs	8,750
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.0460	$/kW-hr, 3,394.0 kW-hr, 8000 hr/yr, 90.0% of capacity	1,248,992
Natural Gas (Fuel)	NA		-
Water	0.22	$/Mgal, 180.0 gpm, 8000 hr/yr, 90.0% of capacity	19,008
Compressed Air	NA		-
Reagent #1(Oxygen)	1.2	$/Mscf, 6.6 mscfh, 8000 hr/yr	57,024
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	5.35	$/Mgal, 180.0 gpm, 8000 hr/yr, 90.0% of capacity	462,240
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**1,819,139**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	19,125
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	435,735
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	435,735
Administration (2% total capital costs)	2%	of total capital costs (TCI)	871,471
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**5,875,100**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**7,694,239**
Pollutant Removed (tons/yr)			**1,219**
Cost per ton of NOx Removed			**6,310**

Notes & Assumptions

1 Aux equip & supports estimated at 5%. Vendor is more complete than other scrubber bids which had a 15% factor for auxiliary equipment.
2 Make up- water & wastewater blowdown rates = 20% of circulating rate per vendor
3 Equipment cost estimate from vendor dated 7/2/2001
4 Oxygen use and electric power use for LTO skid provided by vendor
5 Equipment cost includes instrumentation. Reduced instrumentation factor from 10% to 1% to account for tie-ins to plant control system
6 Used biological treatment cost for wastewater to address treatment for nitrates
7
8

Table I-16: LTO Scrubber - Grate/Kiln Induration - NOx (175-ppm) (Continued)

Capital Recovery Factors			
Primary Installation			
Interest Rate	7.0%		
Equipment Life	20	years	Equipment Life per Vendor
CRF	0.0944		

Catalyst Replacement Cost		
Catalyst Life		years
CRF		
Catalyst cost per unit		$/ft^3
Amount Required		ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life		
CRF		
Rep part cost per unit		$ each
Amount Required		Number
Total Rep Parts Cost		Cost adjusted for freight & sales tax
Installation Labor		10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,000**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	0.5	hr/8 hr shift	500	12,500	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	500	8,750	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	3394	kW-hr	27,152,000	1,248,992	$/kW-hr, 3,394.0 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	180.0	gpm	86,400	19,008	$/Mgal, 180.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Oxygen)	1.2	Mscf	7	mscfh	47,520	57,024	$/Mscf, 6.6 mscfh, 8000 hr/yr
Reagent #2	0	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.0 ton/hr, 175.00 ppm, 8000 hr/yr. 90.0% of capacity
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.0 ton/hr, 175.00 ppm, 8000 hr/yr. 90.0% of capacity
WW Treat	5.35	Mgal	180.0	gpm	86,400	462,240	$/Mgal, 180.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	0	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate					
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Emis Rate T/yr**	**Comments/Notes**
175.0	ppm	300,000	dscfm	1,355	
Controlled Emission Rate					
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Emis Rate T/yr**	**Comments/Notes**
90%	Pct Red			**135**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr				**1,219**	

	Flow acfm	△ P in H2O	Blower Eff	Motor Eff	kW	
Blower						OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	△ P ft H2O	Pump Eff	Motor Eff		
Circ Pump	900					Estimated from Vendor Data (gpm= mscfh gas * 3)
H2O WW Disch	180					Water Makeup Rate/WW Disch = 20% of circulating water rate
LTO Skid Electric Use					3,394	Estimated from Vendor Data
Oxygen Use	6.6	mscfh				Estimated from Vendor Data

ATTACHMENT J

Model BART Cost Analysis - Induration Furnace SO2 Emissions

<u>List of Tables</u>:

Table J-1: BART Screening Evaluation Summary: Straight Grate Induration - Wet Scrubber and Wet Wall ESP

Model Source for Straight Grate Waste Gas Exhaust - SO2 Emissions

General Information

Source Type	Straight Grate Waste Gas Exhaust
Pollutant:	SO2
Existing Pollution Control Equipment	Most sources are routed to a wet scrubber

Control Cost Summary

Control Technology	Control Eff %	Emissions T/y	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton	Air Toxic's & AQRV's?	Energy Impacts?	Non-Air Env Impacts?
Wet Scrubbers High Efficiency	95%	26.93	25.58	572,338	1,124,378	43,950	None	Medium	Waste-water
Wet Scrubbers Low Efficiency	80%	26.93	21.54	572,338	1,124,378	52,190	None	Medium	Waste-water
Wet Wall ElectroStatic Precipitator (WWESP)	80%	26.93	21.54	3,785,848	2,164,096	100,451	None	Low	Waste-water

Comments

Table J-2: BART Screening Evaluation Summary: Grate/Kiln Induration - Wet Scrubber and Wet Wall ESP

Model Source for Grate/Kiln Waste Gas Exhaust - SO2 Emissions

General Information

Source Type	Grate/Kiln Waste Gas Exhaust
Pollutant:	SO2
Existing Pollution Control Equipment	Most sources are routed to a wet scrubber

Control Cost Summary 20 PPM SO2 Case

Control Technology	Control Eff %	Emissions T/y	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton	Air Toxic's & AQRV's?	Energy Impacts?	Non-Air Env Impacts?
Wet Scrubbers High Efficiency	95%	215.4	204.7	1,038,044	2,376,383	11,611	None	High	Waste-Water
Wet Scrubbers Low Efficiency	80%	215.4	172.4	1,038,044	2,376,383	13,788	None	High	Waste-Water
Wet Wall ElectroStatic Precipitator (WWESP)	80%	215.4	172.4	6,010,799	4,155,113	24,108	None	Medium	Waste-Water

Comments

Control Cost Summary PM + 20 PPM SO2 Case

Control Technology	Control Eff %	Emissions T/y	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton	Air Toxic's & AQRV's?	Energy Impacts?	Non-Air Env Impacts?
Wet Scrubbers Low Efficiency	80%SO2 99% PM	630.6	630.6	1,038,044	2,376,383	3,769	None	High	Waste-Water
Wet Wall ElectroStatic Precipitator (WWESP)	80%SO2 99% PM	678.3	630.6	6,010,799	4,155,113	6,589	None	Medium	Waste-Water

Comments: Used PM Emission Rate from High Efficiency PM Scrubber

Control Cost Summary 130 PPM SO2 Case

Control Technology	Control Eff %	Emissions T/y	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton	Air Toxic's & AQRV's?	Energy Impacts?	Non-Air Env Impacts?
Wet Scrubbers High Efficiency	95%	1400.4	1330.3	1,038,044	4,035,263	3,033	None	High	Waste-Water
Wet Scrubbers Low Efficiency	80%	1400.4	1120.3	1,038,044	4,035,263	3,602	None	High	Waste-Water
Wet Wall ElectroStatic Precipitator (WWESP)	80%	1400.4	1120.3	6,010,799	4,984,553	4,449	None	Medium	Waste-Water

Comments

Table J-3: Wet Wall ESP - Straight Grate Induration - SO2
BACT Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
ESP + auxillary equipment		**1,438,720**
Instrumentation	10% of control device cost (A)	143,872
MN Sales Taxes	3% of control device cost (A)	43,162
Freight	5% of control device cost (A)	71,936
Purchased Equipment Total (B)	18%	**1,697,690**
Direct Installation Costs		
Foundations & supports	4% of purchased equip cost (B)	67,908
Handling & erection	50% of purchased equip cost (B)	848,845
Electrical	8% of purchased equip cost (B)	135,815
Piping	1% of purchased equip cost (B)	16,977
Insulation for ductwork	2% of purchased equip cost (B)	33,954
Painting	2% of purchased equip cost (B)	33,954
Direct Installation Costs		**1,137,452**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Total Direct Capital Costs, DC	67%	**2,835,142**
Indirect Capital Costs		
Engineering	20% of purchased equip cost (B)	339,538
Construction & field expenses	20% of purchased equip cost (B)	339,538
Constractor fees	10% of purchased equip cost (B)	169,769
Start-up	1% of purchased equip cost (B)	16,977
Performance Test	1% of purchased equip cost (B)	
Model Study	2% of purchased equip cost (B)	33,954
Contingencies	3% of purchased equip cost (B)	50,931
Total Indirect Capital Costs	57%	**950,706**
Total Capital Investment (TCI) = DC + IC		**3,785,848**
OPERATING COSTS		
Direct Operating Costs		
Operator	25.00 $/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	25,000
Supervisor	15% of operator costs	3,750
Coordinator	33% of operator costs	8,250
Operating materials		
Maintenance Labor	0.1155 $/ft2 collector area; $5775 if < 50,000 ft2	21,017
Maintenance Materials	1% of purchased equipment costs	16,977
Utilities		
Electricity	0.05 $/kW-hr, 365 kW-hr, 8000 hr/yr, 90.0% of capacity	134,390
Water	0.20 $/Mgal, 1,699.8 gpm, 8000 hr/yr, 90.0% of capacity	163,179
Solid Waste Disposal	NA	-
Wastewater Treatment	1.50 $/Mgal, 1,699.8 gpm, 8000 hr/yr, 90.0% of capacity	1,223,845
Reagent (Caustic)	280.00 $/Ton, 16.8 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	18,851
Total Annual Direct Operating Costs, DC		**1,615,259**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	40,046
Administration (2% total capital costs)	2% of total capital costs (TCI)	75,717
Property tax (1% total capital costs)	1% of total capital costs (TCI)	37,858
Insurance (1% total capital costs)	1% of total capital costs (TCI)	37,858
Captial Recovery	9% for a 20- year equipment life and a 7% interest rate	357,357
Total Indirect Operating Costs		**548,838**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**2,164,096**
Pollutant Removed (tons/yr)[B]		**21.5**
Cost per ton of SO2 Removed		**100,451**

Notes & Assumptions

1 Equipment cost estimates assumed to be 3% higher than that of dry ESP.
2 EPA Cost Manual 6th Ed. 2002
3
4
5
6
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Table J-3: Wet Wall ESP - Straight Grate Induration - SO2 (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	150,000	dscfm	170455	scfm
	135	Temp Deg F		
	12%	% Moisture		
	188,865	acfm		

Operating Cost Calculations — **Annual hours of operation: 8,000** — **Utilization Rate: 90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	1	hr/8 hr shift	1,000	25,000	$/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	25				NA	NA	Calc'd as % of labor costs
Maint Labor	0.1155	$/ft^2 collector	57,401	ft^2 collector area		6,630	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	17.5				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	365.2	kW-hr	2,921,526	134,390	$/kW-hr, 365 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.2	Mgal	1700	gpm	815,896	163,179	$/Mgal, 1,699.8 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	16.831	lb/hr	67	18,851	$/Ton, 16.8 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0.000	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	0	Ton	0.857	ton/hr	6,857	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.5	Mgal	1700	gpm	815,896	1,223,845	$/Mgal, 1,699.8 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
5	ppm	150,000	dscfm	NA	27	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				80%	**5.39**	Currently assumes 80%.
Emission Reduction T/yr					**21.5**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	188,865	5	0.55	0.9	223.2	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	Δ P ft H2O	Pump Eff	Motor Eff		
Pump 1	1700	60	0.8	0.9	26.6	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	0	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	57,401	111.4	2	4	115.4	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Caustic Use	6.73 lb/hr SO2	2.50 lb NaOH/lb SO2	16.83	lb/hr Caustic
Lime Use	6.73 lb/hr SO2	1.53 lb Lime/lb SO2	10.301	lb/hr Lime

Estimate Area (ft2)

Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	188,865	acfm
Area #2	**57401.0235**	**ft2**

Table J-4: Wet Wall ESP - Grate/Kiln Induration - SO2 (20-ppm)
BACT Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
ESP + auxillary equipment		**2,284,259**
Instrumentation	10% of control device cost (A)	228,426
MN Sales Taxes	3% of control device cost (A)	68,528
Freight	5% of control device cost (A)	114,213
Purchased Equipment Total (B)	18%	**2,695,426**
Direct Installation Costs		
Foundations & supports	4% of purchased equip cost (B)	107,817
Handling & erection	50% of purchased equip cost (B)	1,347,713
Electrical	8% of purchased equip cost (B)	215,634
Piping	1% of purchased equip cost (B)	26,954
Insulation for ductwork	2% of purchased equip cost (B)	53,909
Painting	2% of purchased equip cost (B)	53,909
Direct Installation Costs		**1,805,935**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Total Direct Capital Costs, DC	67%	**4,501,361**
Indirect Capital Costs		
Engineering	20% of purchased equip cost (B)	539,085
Construction & field expenses	20% of purchased equip cost (B)	539,085
Constractor fees	10% of purchased equip cost (B)	269,543
Start-up	1% of purchased equip cost (B)	26,954
Performance Test	1% of purchased equip cost (B)	
Model Study	2% of purchased equip cost (B)	53,909
Contingencies	3% of purchased equip cost (B)	80,863
Total Indirect Capital Costs	57%	**1,509,438**
Total Capital Investment (TCI) = DC + IC		**6,010,799**
OPERATING COSTS		
Direct Operating Costs		
Operator	25.00 $/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	25,000
Supervisor	15% of operator costs	3,750
Coordinator	33% of operator costs	8,250
Operating materials		
Maintenance Labor	0.1155 $/ft2 collector area; $5775 if < 50,000 ft2	36,102
Maintenance Materials	1% of purchased equipment costs	26,954
Utilities		
Electricity	0.05 $/kW-hr, 726 kW-hr, 8000 hr/yr, 90.0% of capacity	267,308
Water	0.20 $/Mgal, 3,399.6 gpm, 8000 hr/yr, 90.0% of capacity	326,359
Solid Waste Disposal	NA	-
Wastewater Treatment	1.50 $/Mgal, 3,399.6 gpm, 8000 hr/yr, 90.0% of capacity	2,447,689
Reagent (Caustic)	280.00 $/Ton, 134.6 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	150,807
Total Annual Direct Operating Costs, DC		**3,292,220**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	55,084
Administration (2% total capital costs)	2% of total capital costs (TCI)	120,216
Property tax (1% total capital costs)	1% of total capital costs (TCI)	60,108
Insurance (1% total capital costs)	1% of total capital costs (TCI)	60,108
Captial Recovery	9% for a 20- year equipment life and a 7% interest rate	567,377
Total Indirect Operating Costs		**862,893**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**4,155,113**
Pollutant Removed (tons/yr)[B]		**172.4**
Cost per ton of SO2 Removed		**24,108**

Notes & Assumptions

1 Equipment cost estimates assumed to be 3% higher than that of dry ESP.
2 EPA Cost Manual 6th Ed. 2002
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Table J-4: Wet Wall ESP - Grate/Kiln Induration - SO2 (20-ppm) (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	300,000	dscfm	340909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations				**Annual hours of operation:**	**8,000**		
				Utilization Rate:		**90.0%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	1	hr/8 hr shift	1,000	25,000	$/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	25				NA	NA	Calc'd as % of labor costs
Maint Labor	0.1155	$/ft^2 collector	114,802	ft^2 collector area		13,260	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	17.5				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	726.4	kW-hr	5,811,053	267,308	$/kW-hr, 726 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.2	Mgal	3400	gpm	1,631,793	326,359	$/Mgal, 3,399.6 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	134.649	lb/hr	539	150,807	$/Ton, 134.6 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	0	Ton	0.857	ton/hr	6,857	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.5	Mgal	3400	gpm	1,631,793	2,447,689	$/Mgal, 3,399.6 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
20	ppm	300,000	dscfm	NA	**215.44**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				80%	**43.09**	Currently assumes 80%.
Emission Reduction T/yr					**172.4**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	377,730	5	0.55	0.9	446.4	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	Δ P ft H2O	Pump Eff	Motor Eff		
Pump 1	3400	60	0.8	0.9	53.3	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	0	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	114,802	222.7	2	4	226.7	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Caustic Use	53.86	lb/hr SO2	2.50	lb NaOH/lb SO2	134.65	lb/hr Caustic
Lime Use	53.86	lb/hr SO2	1.53	lb Lime/lb SO2	82.405	lb/hr Lime

Estimate Area (ft2)

Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	377,730	acfm
Area #2	**114802.047**	**ft2**

Table J-5: Wet Wall ESP - Grate/Kiln Induration - SO2 (20-ppm) + PM
BACT Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**2,284,259**
Instrumentation	10%	of control device cost (A)	228,426
MN Sales Taxes	3%	of control device cost (A)	68,528
Freight	5%	of control device cost (A)	114,213
Purchased Equipment Total (B)	18%		**2,695,426**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	107,817
Handling & erection	50%	of purchased equip cost (B)	1,347,713
Electrical	8%	of purchased equip cost (B)	215,634
Piping	1%	of purchased equip cost (B)	26,954
Insulation for ductwork	2%	of purchased equip cost (B)	53,909
Painting	2%	of purchased equip cost (B)	53,909
Direct Installation Costs			**1,805,935**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**4,501,361**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	539,085
Construction & field expenses	20%	of purchased equip cost (B)	539,085
Constractor fees	10%	of purchased equip cost (B)	269,543
Start-up	1%	of purchased equip cost (B)	26,954
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	53,909
Contingencies	3%	of purchased equip cost (B)	80,863
Total Indirect Capital Costs	57%		**1,509,438**
Total Capital Investment (TCI) = DC + IC			**6,010,799**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.00	$/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	25,000
Supervisor	15%	of operator costs	3,750
Coordinator	33%	of operator costs	8,250
Operating materials			
Maintenance Labor	0.1155	$/ft2 collector area; $5775 if < 50,000 ft2	36,102
Maintenance Materials	1%	of purchased equipment costs	26,954
Utilities			
Electricity	0.05	$/kW-hr, 726 kW-hr, 8000 hr/yr, 90.0% of capacity	267,308
Water	0.20	$/Mgal, 3,399.6 gpm, 8000 hr/yr, 90.0% of capacity	326,359
Solid Waste Disposal	NA		-
Wastewater Treatment	1.50	$/Mgal, 3,399.6 gpm, 8000 hr/yr, 90.0% of capacity	2,447,689
Reagent (Caustic)	280.00	$/Ton, 134.6 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	150,807
Total Annual Direct Operating Costs, DC			**3,292,220**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,084
Administration (2% total capital costs)	2%	of total capital costs (TCI)	120,216
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	60,108
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	60,108
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	567,377
Total Indirect Operating Costs			**862,893**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,155,113**
Pollutant Removed SO_2 + PM (tons/yr)[B]			**630.6**
Cost per ton of SO_2 + PM Removed			**6,589**

Notes & Assumptions

1 Equipment cost estimates assumed to be 3% higher than that of dry ESP.
2 EPA Cost Manual 6th Ed. 2002
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Table J-5: Wet Wall ESP - Grate/Kiln Induration - SO2 (20-ppm) + PM (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cell

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	300,000	dscfm	340909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations — **Annual hours of operation: 8,000** — **Utilization Rate: 90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	1	hr/8 hr shift	1,000	25,000	$/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	25				NA	NA	Calc'd as % of labor costs
Maint Labor	0.1155	$/ft^2 collector	114,802	ft^2 collector area		13,260	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	17.5				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	726.4	kW-hr	5,811,053	267,308	$/kW-hr, 726 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.2	Mgal	3400	gpm	1,631,793	326,359	$/Mgal, 3,399.6 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	134.649	lb/hr	539	150,807	$/Ton, 134.6 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	0	Ton	0.857	ton/hr	6,857	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.5	Mgal	3400	gpm	1,631,793	2,447,689	$/Mgal, 3,399.6 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**	
20	ppm	300,000	dscfm	NA	**215.44**	SO_2 + PM	**678.30**

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				80%	**43.09**	Currently assumes 80%.
Emission Reduction SO_2 T/yr					**172.4**	
Emission Reduction PM T/yr					**458.2**	
Emission Reduction $SO_{2\,+}$ PM T/yr					**630.6**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	377,730	5	0.55	0.9	446.4	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	Δ P ft H2O	Pump Eff	Motor Eff		
Pump 1	3400	60	0.8	0.9	53.3	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	0	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	114,802	222.7	2	4	226.7	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Caustic Use	53.86	lb/hr SO2	2.50	lb NaOH/lb SO2	134.65	lb/hr Caustic
Lime Use	53.86	lb/hr SO2	1.53	lb Lime/lb SO2	82.405	lb/hr Lime

Estimate Area (ft2)

Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	377,730	acfm
Area #2	**114802.047**	**ft2**

Table J-6: Wet Wall ESP - Grate/Kiln Induration - SO2 (130-ppm)
BACT Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
ESP + auxillary equipment		**2,284,259**
Instrumentation	10% of control device cost (A)	228,426
MN Sales Taxes	3% of control device cost (A)	68,528
Freight	5% of control device cost (A)	114,213
Purchased Equipment Total (B)	18%	**2,695,426**
Direct Installation Costs		
Foundations & supports	4% of purchased equip cost (B)	107,817
Handling & erection	50% of purchased equip cost (B)	1,347,713
Electrical	8% of purchased equip cost (B)	215,634
Piping	1% of purchased equip cost (B)	26,954
Insulation for ductwork	2% of purchased equip cost (B)	53,909
Painting	2% of purchased equip cost (B)	53,909
Direct Installation Costs		**1,805,935**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Total Direct Capital Costs, DC	67%	**4,501,361**
Indirect Capital Costs		
Engineering	20% of purchased equip cost (B)	539,085
Construction & field expenses	20% of purchased equip cost (B)	539,085
Constractor fees	10% of purchased equip cost (B)	269,543
Start-up	1% of purchased equip cost (B)	26,954
Performance Test	1% of purchased equip cost (B)	
Model Study	2% of purchased equip cost (B)	53,909
Contingencies	3% of purchased equip cost (B)	80,863
Total Indirect Capital Costs	57%	**1,509,438**
Total Capital Investment (TCI) = DC + IC		**6,010,799**
OPERATING COSTS		
Direct Operating Costs		
Operator	25.00 $/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capac	25,000
Supervisor	15% of operator costs	3,750
Coordinator	33% of operator costs	8,250
Operating materials		
Maintenance Labor	0.1155 $/ft2 collector area; $5775 if < 50,000 ft2	36,102
Maintenance Materials	1% of purchased equipment costs	26,954
Utilities		
Electricity	0.05 $/kW-hr, 726 kW-hr, 8000 hr/yr, 90.0% of capac	267,308
Water	0.20 $/Mgal, 3,399.6 gpm, 8000 hr/yr, 90.0% of capac	326,359
Solid Waste Disposal	NA	-
Wastewater Treatment	1.50 $/Mgal, 3,399.6 gpm, 8000 hr/yr, 90.0% of capac	2,447,689
Reagent (Caustic)	280.00 $/Ton, 875.2 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 w	980,247
Total Annual Direct Operating Costs, DC		**4,121,660**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	55,084
Administration (2% total capital costs)	2% of total capital costs (TCI)	120,216
Property tax (1% total capital costs)	1% of total capital costs (TCI)	60,108
Insurance (1% total capital costs)	1% of total capital costs (TCI)	60,108
Captial Recovery	9% for a 20- year equipment life and a 7% interest ra	567,377
Total Indirect Operating Costs		**862,893**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**4,984,553**
Pollutant Removed (tons/yr)[B]		**1,120.3**
Cost per ton of SO2 Removed		**4,449**

Notes & Assumptions

1 Equipment cost estimates assumed to be 3% higher than that of dry ESP.
2 EPA Cost Manual 6th Ed. 2002
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Table J-6: Wet Wall ESP - Grate/Kiln Induration - SO2 (130-ppm) (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	300,000	dscfm	340909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations — **Annual hours of operation: 8,000** — **Utilization Rate: 90.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Op Labor	25	Hr	1	hr/8 hr shift	1,000	25,000	$/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	25				NA	NA	Calc'd as % of labor costs
Maint Labor	0.1155	$/ft^2 collector	114,802	ft^2 collector area		13,260	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	17.5				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	726.4	kW-hr	5,811,053	267,308	$/kW-hr, 726 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.2	Mgal	3400	gpm	1,631,793	326,359	$/Mgal, 3,399.6 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	875.221	lb/hr	3,501	980,247	$/Ton, 875.2 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	0	Ton	0.857	ton/hr	6,857	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.5	Mgal	3400	gpm	1,631,793	2,447,689	$/Mgal, 3,399.6 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
130	ppm	300,000	dscfm	NA	**1400.35**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				80%	**280.07**	Currently assumes 80%.
Emission Reduction T/yr					**1120.3**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	377,730	5	0.55	0.9	446.4	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	Δ P ft H2O	Pump Eff	Motor Eff		
Pump 1	3400	60	0.8	0.9	53.3	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	0	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	114,802	222.7	2	4	226.7	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Caustic Use	350.09	lb/hr SO2	2.50	lb NaOH/lb SO2	875.22 lb/hr Caustic
Lime Use	350.09	lb/hr SO2	1.53	lb Lime/lb SO2	535.635 lb/hr Lime

Estimate Area (ft2)

Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	377,730	acfm
Area #2	**114802.047**	**ft2**

Table J-7: Low Efficiency Wet Scrubber - Straight Grate Induration - SO2
BART Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**220,469**
Instrumentation	10%	of control device cost (A)	22,047
MN Sales Taxes	3.0%	of control device cost (A)	6,614
Freight	5%	of control device cost (A)	11,023
Purchased Equipment Total (B)	18%		**260,153**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	31,218
Handling & erection	40%	of purchased equip cost (B)	104,061
Electrical	1%	of purchased equip cost (B)	2,602
Piping	30%	of purchased equip cost (B)	78,046
Insulation	1%	of purchased equip cost (B)	2,602
Painting	1%	of purchased equip cost (B)	2,602
Installation Total	85%		**221,130**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**481,284**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	26,015
Construction & field expenses	10%	of purchased equip cost (B)	26,015
Construction fee	10%	of purchased equip cost (B)	26,015
Start-up	1%	of purchased equip cost (B)	2,602
Performance test	1%	of purchased equip cost (B)	2,602
Contingencies	3%	of purchased equip cost (B)	7,805
Total Indirect Capital Costs, IC	35%		**91,054**
Total Capital Investment (TCI) = DC + IC			**572,338**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.00	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	11,250
Supervisor	15%	of oper labor costs 15%	1,688
Operating Materials			
Reagent #1	280	$/Ton, 16.8 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	18,851
Reagent #2	NA	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA		-
Wastewater Treatment	1.50	$/Mgal, 340.0 gpm, 8000 hr/yr, 90.0% of capacity	220,292
Maintenance			
Maintenance Labor	17.50	1/2 hr per shift	8,750
Maintenance Materials	100%	of maintenance labor costs	8,750
Electricity - Fan, Pump	0.05	$/kW-hr, 698 kW-hr, 8000 hr/yr, 90.0% of capacity	231,287
Total Annual Direct Operating Costs			**500,867**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	18,263
Administration (2% total capital costs)	2%	of total capital costs (TCI)	11,447
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	5,723
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	5,723
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	81,488
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**623,511**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,124,378**
Pollutant Removed (tons/yr)[B]			**22**
Cost per ton of SO2 Removed			**52,190**

Notes & Assumptions

1 EPA Air Pollution Control Cost Manual 6th Ed 2002
2
3
4
5
6

Table J-7: Low Efficiency Wet Scrubber - Straight Grate Induration - SO2 (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	150,000	dscfm	170455	scfm
	135	Temp Deg F		
	12%	% Moisture		
	188,865	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,000**; **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	0.5	hr/8 hr shift	450	11,250	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,688	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	450	4,125	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	698.3	kW-hr	5,027,971	231,287	$/kW-hr, 698 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.2	Mgal	340.0	gpm	146,861	29,372	$/Mgal, 340.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	16.83	lb/hr	67	18,851	$/Ton, 16.8 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0.000	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.5	Mgal	340.0	gpm	146,861	220,292	$/Mgal, 340.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
5	ppm	150,000	dscfm	NA	**26.93**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 80%**	**Emis Rate T/yr**	**Currently assumes 80%.**
				80%	**5**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**21.5**	Assuming 80% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	169,978	12	0.55	0.7	619.9	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	1,700	125	0.8	0.7	71.3	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	340.0	62.5	0.8	0.7	7.1	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	6.73 lb/hr SO2	2.50	lb NaOH/lb SO2	16.83 lb/hr Caustic
Lime Use	6.73 lb/hr SO2	1.53	lb Lime/lb SO2	10.30 lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8000 hr/yr, 90.0% of capacity

Table J-8: High Efficiency Wet Scrubber - Straight Grate Induration - SO2
BART Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**220,469**
Instrumentation	10%	of control device cost (A)	22,047
MN Sales Taxes	3.0%	of control device cost (A)	6,614
Freight	5%	of control device cost (A)	11,023
Purchased Equipment Total (B)	18%		**260,153**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	31,218
Handling & erection	40%	of purchased equip cost (B)	104,061
Electrical	1%	of purchased equip cost (B)	2,602
Piping	30%	of purchased equip cost (B)	78,046
Insulation	1%	of purchased equip cost (B)	2,602
Painting	1%	of purchased equip cost (B)	2,602
Installation Total	85%		**221,130**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**481,284**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	26,015
Construction & field expenses	10%	of purchased equip cost (B)	26,015
Construction fee	10%	of purchased equip cost (B)	26,015
Start-up	1%	of purchased equip cost (B)	2,602
Performance test	1%	of purchased equip cost (B)	2,602
Contingencies	3%	of purchased equip cost (B)	7,805
Total Indirect Capital Costs, IC	35%		**91,054**
Total Capital Investment (TCI) = DC + IC			**572,338**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.00	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	11,250
Supervisor	15%	of oper labor costs 15%	1,688
Operating Materials			
Reagent #1	280	$/Ton, 16.8 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	18,851
Reagent #2	NA	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA		-
Wastewater Treatment	1.50	$/Mgal, 340.0 gpm, 8000 hr/yr, 90.0% of capacity	220,292
Maintenance			
Maintenance Labor	17.50	1/2 hr per shift	8,750
Maintenance Materials	100%	of maintenance labor costs	8,750
Electricity - Fan, Pump	0.05	$/kW-hr, 698 kW-hr, 8000 hr/yr, 90.0% of capacity	231,287
Total Annual Direct Operating Costs			**500,867**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	18,263
Administration (2% total capital costs)	2%	of total capital costs (TCI)	11,447
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	5,723
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	5,723
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	81,488
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**623,511**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,124,378**
Pollutant Removed (tons/yr)[B]			**26**
Cost per ton of SO2 Removed			**43,950**

Notes & Assumptions

1 EPA Air Pollution Control Cost Manual 6th Ed 2002
2
3
4
5
6

Table J-8: High Efficiency Wet Scrubber - Straight Grate Induration - SO2 (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	150,000	dscfm	170455	scfm
	135	Temp Deg F		
	12%	% Moisture		
	188,865	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,000**; **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	0.5	hr/8 hr shift	450	11,250	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,688	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	450	4,125	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	698.3	kW-hr	5,027,971	231,287	$/kW-hr, 698 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.2	Mgal	340.0	gpm	146,861	29,372	$/Mgal, 340.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	16.83	lb/hr	67	18,851	$/Ton, 16.8 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.5	Mgal	340.0	gpm	146,861	220,292	$/Mgal, 340.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
5	ppm	150,000	dscfm	NA	**26.9**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				95%	**1**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**25.6**	Assuming 95% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	169,978	12	0.55	0.7	619.9	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	1,700	125	0.8	0.7	71.3	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	340.0	62.5	0.8	0.7	7.1	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	6.73 lb/hr SO2	2.50	lb NaOH/lb SO2	16.83	lb/hr Caustic
Lime Use	6.73 lb/hr SO2	1.53	lb Lime/lb SO2	10.30	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8000 hr/yr, 90.0% of capacity

Table J-9: Low Efficiency Wet Scrubber - Grate/Kiln Induration - SO2(20 ppm)
BART Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**399,863**
Instrumentation	10%	of control device cost (A)	39,986
MN Sales Taxes	3.0%	of control device cost (A)	11,996
Freight	5%	of control device cost (A)	19,993
Purchased Equipment Total (B)	18%		**471,838**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	56,621
Handling & erection	40%	of purchased equip cost (B)	188,735
Electrical	1%	of purchased equip cost (B)	4,718
Piping	30%	of purchased equip cost (B)	141,552
Insulation	1%	of purchased equip cost (B)	4,718
Painting	1%	of purchased equip cost (B)	4,718
Installation Total	85%		**401,063**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**872,901**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	47,184
Construction & field expenses	10%	of purchased equip cost (B)	47,184
Construction fee	10%	of purchased equip cost (B)	47,184
Start-up	1%	of purchased equip cost (B)	4,718
Performance test	1%	of purchased equip cost (B)	4,718
Contingencies	3%	of purchased equip cost (B)	14,155
Total Indirect Capital Costs, IC	35%		**165,143**
Total Capital Investment (TCI) = DC + IC			**1,038,044**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.00	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	11,250
Supervisor	15%	of oper labor costs 15%	1,688
Operating Materials			
Reagent #1	280	$/Ton, 134.6 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	150,807
Reagent #2	NA		-
Catalyst	NA		-
Wastewater Treatment	1.50	$/Mgal, 679.9 gpm, 8000 hr/yr, 90.0% of capacity	440,584
Maintenance			
Maintenance Labor	17.50	1/2 hr per shift	8,750
Maintenance Materials	100%	of maintenance labor costs	8,750
Electricity - Fan, Pump	0.05	$/kW-hr, 1,397 kW-hr, 8000 hr/yr, 90.0% of capacity	462,573
Total Annual Direct Operating Costs			**1,084,402**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	18,263
Administration (2% total capital costs)	2%	of total capital costs (TCI)	20,761
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	10,380
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	10,380
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	147,794
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,291,981**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,376,383**
Pollutant Removed (tons/yr)[B]			**172**
Cost per ton of SO2 Removed			**13,788**

Notes & Assumptions

1 EPA Air Pollution Control Cost Manual 6th Ed 2002
2
3
4
5
6

Table J-9: Low Efficiency Wet Scrubber - Grate/Kiln Induration - SO2(20 ppm) (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	300,000	dscfm	340,909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations **Annual hours of operation:** **8,000** **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	0.5	hr/8 hr shift	450	11,250	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,688	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	450	4,125	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	1396.7	kW-hr	10,055,941	462,573	$/kW-hr, 1,397 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.2	Mgal	679.9	gpm	293,723	58,745	$/Mgal, 679.9 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	134.65	lb/hr	539	150,807	$/Ton, 134.6 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.5	Mgal	679.9	gpm	293,723	440,584	$/Mgal, 679.9 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
20	ppm	300,000	dscfm	NA	**215.4**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 80%**	**Emis Rate T/yr**	**Currently assumes 80%.**
				80%	**43**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**172.4**	Assuming 80% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	339,957	12	0.55	0.7	1239.7	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	3,400	125	0.8	0.7	142.7	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	679.9	62.5	0.8	0.7	14.3	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	53.86 lb/hr SO2	2.50 lb NaOH/lb SO2	134.65	lb/hr Caustic
Lime Use	53.86 lb/hr SO2	1.53 lb Lime/lb SO2	82.41	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8000 hr/yr, 90.0% of capacity

Table J-10: Low Efficiency Wet Scrubber - Grate/Kiln Induration - SO2 (20-ppm) + PM
BART Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC		**399,863**
Instrumentation	10% of control device cost (A)	39,986
MN Sales Taxes	3.0% of control device cost (A)	11,996
Freight	5% of control device cost (A)	19,993
Purchased Equipment Total (B)	18%	**471,838**
Installation		
Foundations & supports	12% of purchased equip cost (B)	56,621
Handling & erection	40% of purchased equip cost (B)	188,735
Electrical	1% of purchased equip cost (B)	4,718
Piping	30% of purchased equip cost (B)	141,552
Insulation	1% of purchased equip cost (B)	4,718
Painting	1% of purchased equip cost (B)	4,718
Installation Total	85%	**401,063**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Total Direct Capital Cost, DC		**872,901**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	47,184
Construction & field expenses	10% of purchased equip cost (B)	47,184
Construction fee	10% of purchased equip cost (B)	47,184
Start-up	1% of purchased equip cost (B)	4,718
Performance test	1% of purchased equip cost (B)	4,718
Contingencies	3% of purchased equip cost (B)	14,155
Total Indirect Capital Costs, IC	35%	**165,143**
Total Capital Investment (TCI) = DC + IC		**1,038,044**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	25.00 $/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	11,250
Supervisor	15% of oper labor costs 15%	1,688
Operating Materials		
Reagent #1	280 $/Ton, 134.6 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	150,807
Reagent #2	NA	-
Catalyst	NA	-
Wastewater Treatment	1.50 $/Mgal, 679.9 gpm, 8000 hr/yr, 90.0% of capacity	440,584
Maintenance		
Maintenance Labor	17.50 1/2 hr per shift	8,750
Maintenance Materials	100% of maintenance labor costs	8,750
Electricity - Fan, Pump	0.05 $/kW-hr, 1,397 kW-hr, 8000 hr/yr, 90.0% of capacity	462,573
Total Annual Direct Operating Costs		**1,084,402**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	18,263
Administration (2% total capital costs)	2% of total capital costs (TCI)	20,761
Property tax (1% total capital costs)	1% of total capital costs (TCI)	10,380
Insurance (1% total capital costs)	1% of total capital costs (TCI)	10,380
Capital Recovery	14.24% for a 10- year equipment life and a 7% interest rate	147,794
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**1,291,981**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**2,376,383**
Pollutant Removed SO_2 + PM (tons/yr)[B]		**631**
Cost per ton of SO2 and PM Removed		**3,769**

Notes & Assumptions

1 EPA Air Pollution Control Cost Manual 6th Ed 2002
2 Used PM Emission Rate from Hi Eff Scrubber
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Table J-10: Low Efficiency Wet Scrubber - Grate/Kiln Induration - SO2 (20-ppm) + PM (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	300,000	dscfm	340,909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,000**; **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	0.5	hr/8 hr shift	450	11,250	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,688	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	450	4,125	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	1396.7	kW-hr	10,055,941	462,573	$/kW-hr, 1,397 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.2	Mgal	679.9	gpm	293,723	58,745	$/Mgal, 679.9 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	134.65	lb/hr	539	150,807	$/Ton, 134.6 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.5	Mgal	679.9	gpm	293,723	440,584	$/Mgal, 679.9 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacit
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
20	ppm	300,000	dscfm	NA	**215.4**	SO_2 + PM **678.30**
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 80%**	**Emis Rate T/yr**	**Currently assumes 80%.**
				80%	**43**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction SO_2 T/yr					**172.4**	Assuming 80% control.
Emission Reduction PM T/yr					**458.2**	
Emission Reduction SO_{2+} PM T/yr					**630.6**	

	Flow acfm	∆ P in H2O	Blower Eff	Motor Eff	kW	
Blower	339,957	12	0.55	0.7	1239.7	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	3,400	125	0.8	0.7	142.7	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	679.9	62.5	0.8	0.7	14.3	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	53.86	lb/hr SO2	2.50 lb NaOH/lb SO2	134.65	lb/hr Caustic
Lime Use	53.86	lb/hr SO2	1.53 lb Lime/lb SO2	82.41	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8000 hr/yr, 90.0% of capacity

Table J-11: Low Efficiency Wet Scrubber - Grate/Kiln Induration - SO2 (130-ppm)
BART Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**399,863**
Instrumentation	10%	of control device cost (A)	39,986
MN Sales Taxes	3.0%	of control device cost (A)	11,996
Freight	5%	of control device cost (A)	19,993
Purchased Equipment Total (B)	18%		**471,838**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	56,621
Handling & erection	40%	of purchased equip cost (B)	188,735
Electrical	1%	of purchased equip cost (B)	4,718
Piping	30%	of purchased equip cost (B)	141,552
Insulation	1%	of purchased equip cost (B)	4,718
Painting	1%	of purchased equip cost (B)	4,718
Installation Total	85%		**401,063**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**872,901**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	47,184
Construction & field expenses	10%	of purchased equip cost (B)	47,184
Construction fee	10%	of purchased equip cost (B)	47,184
Start-up	1%	of purchased equip cost (B)	4,718
Performance test	1%	of purchased equip cost (B)	4,718
Contingencies	3%	of purchased equip cost (B)	14,155
Total Indirect Capital Costs, IC	35%		**165,143**
Total Capital Investment (TCI) = DC + IC			**1,038,044**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.00	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	11,250
Supervisor	15%	of oper labor costs 15%	1,688
Operating Materials			
Reagent #1	280	$/Ton, 875.2 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	980,247
Reagent #2	NA		-
Catalyst	NA		-
Wastewater Treatment	1.50	$/Mgal, 679.9 gpm, 8000 hr/yr, 90.0% of capacity	440,584
Maintenance			
Maintenance Labor	17.50	1/2 hr per shift	8,750
Maintenance Materials	100%	of maintenance labor costs	8,750
Electricity - Fan, Pump	0.05	$/kW-hr, 1,397 kW-hr, 8000 hr/yr, 90.0% of capacity	462,573
Total Annual Direct Operating Costs			**1,913,842**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	18,263
Administration (2% total capital costs)	2%	of total capital costs (TCI)	20,761
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	10,380
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	10,380
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	147,794
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**2,121,421**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,035,263**
Pollutant Removed (tons/yr)[B]			**1,120**
Cost per ton of SO2 Removed			**3,602**

Notes & Assumptions

1 EPA Air Pollution Control Cost Manual 6th Ed 2002
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Table J-11: Low Efficiency Wet Scrubber - Grate/Kiln Induration - SO2 (130-ppm) (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	300,000	dscfm	340,909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,000**; **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	0.5	hr/8 hr shift	450	11,250	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,688	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	450	4,125	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	1396.7	kW-hr	10,055,941	462,573	$/kW-hr, 1,397 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.2	Mgal	679.9	gpm	293,723	58,745	$/Mgal, 679.9 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	875.22	lb/hr	3,501	980,247	$/Ton, 875.2 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.5	Mgal	679.9	gpm	293,723	440,584	$/Mgal, 679.9 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
130	ppm	300,000	dscfm	NA	**1,400.4**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 80%**	**Emis Rate T/yr**	**Currently assumes 80%.**
				80%	**280**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1120.3**	Assuming 80% control.

	Flow acfm	∆ P in H2O	Blower Eff	Motor Eff	kW	
Blower	339,957	12	0.55	0.7	1239.7	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	3,400	125	0.8	0.7	142.7	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	679.9	62.5	0.8	0.7	14.3	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	350.09 lb/hr SO2	2.50	lb NaOH/lb SO2	875.22 lb/hr Caustic
Lime Use	350.09 lb/hr SO2	1.53	lb Lime/lb SO2	535.64 lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8000 hr/yr, 90.0% of capacity

Table J-12: High Efficiency Wet Scrubber - Grate/Kiln Induration - SO2 (20-ppm)
BART Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC		**399,863**
Instrumentation	10% of control device cost (A)	39,986
MN Sales Taxes	3.0% of control device cost (A)	11,996
Freight	5% of control device cost (A)	19,993
Purchased Equipment Total (B)	18%	**471,838**
Installation		
Foundations & supports	12% of purchased equip cost (B)	56,621
Handling & erection	40% of purchased equip cost (B)	188,735
Electrical	1% of purchased equip cost (B)	4,718
Piping	30% of purchased equip cost (B)	141,552
Insulation	1% of purchased equip cost (B)	4,718
Painting	1% of purchased equip cost (B)	4,718
Installation Total	85%	**401,063**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Total Direct Capital Cost, DC		**872,901**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	47,184
Construction & field expenses	10% of purchased equip cost (B)	47,184
Construction fee	10% of purchased equip cost (B)	47,184
Start-up	1% of purchased equip cost (B)	4,718
Performance test	1% of purchased equip cost (B)	4,718
Contingencies	3% of purchased equip cost (B)	14,155
Total Indirect Capital Costs, IC	35%	**165,143**
Total Capital Investment (TCI) = DC + IC		**1,038,044**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	25.00 $/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	11,250
Supervisor	15% of oper labor costs 15%	1,688
Operating Materials		
Reagent #1	280 $/Ton, 134.6 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	150,807
Reagent #2	NA $/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA	-
Wastewater Treatment	1.50 $/Mgal, 679.9 gpm, 8000 hr/yr, 90.0% of capacity	440,584
Maintenance		
Maintenance Labor	17.50 1/2 hr per shift	8,750
Maintenance Materials	100% of maintenance labor costs	8,750
Electricity - Fan, Pump	0.05 $/kW-hr, 1,397 kW-hr, 8000 hr/yr, 90.0% of capacity	462,573
Total Annual Direct Operating Costs		**1,084,402**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	18,263
Administration (2% total capital costs)	2% of total capital costs (TCI)	20,761
Property tax (1% total capital costs)	1% of total capital costs (TCI)	10,380
Insurance (1% total capital costs)	1% of total capital costs (TCI)	10,380
Capital Recovery	14.24% for a 10- year equipment life and a 7% interest rate	147,794
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**1,291,981**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**2,376,383**
Pollutant Removed (tons/yr)[B]		**205**
Cost per ton of SO2 Removed		**11,611**

Notes & Assumptions

3 EPA Air Pollution Control Cost Manual 6th Ed 2002
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Table J-12: High Efficiency Wet Scrubber - Grate/Kiln Induration - SO2 (20-ppm) (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	300,000	dscfm	340,909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,000** — **Utilization Rate:** **90.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Op Labor	25	Hr	0.5	hr/8 hr shift	450	11,250	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,688	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	450	4,125	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	1396.7	kW-hr	10,055,941	462,573	$/kW-hr, 1,397 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.2	Mgal	679.9	gpm	293,723	58,745	$/Mgal, 679.9 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	134.65	lb/hr	539	150,807	$/Ton, 134.6 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.5	Mgal	679.9	gpm	293,723	440,584	$/Mgal, 679.9 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
20	ppm	300,000	dscfm	NA	**215.4**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				95%	**11**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**204.7**	Assuming 95% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	339,957	12	0.55	0.7	1239.7	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	3,400	125	0.8	0.7	142.7	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	679.9	62.5	0.8	0.7	14.3	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	53.86	lb/hr SO2	2.50	lb NaOH/lb SO2	134.65	lb/hr Caustic
Lime Use	53.86	lb/hr SO2	1.53	lb Lime/lb SO2	82.41	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8000 hr/yr, 90.0% of capacity

Table J-13: High Efficiency Wet Scrubber - Grate/Kiln Induration - SO2 (130-ppm)
BART Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**399,863**
Instrumentation	10%	of control device cost (A)	39,986
MN Sales Taxes	3.0%	of control device cost (A)	11,996
Freight	5%	of control device cost (A)	19,993
Purchased Equipment Total (B)	18%		**471,838**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	56,621
Handling & erection	40%	of purchased equip cost (B)	188,735
Electrical	1%	of purchased equip cost (B)	4,718
Piping	30%	of purchased equip cost (B)	141,552
Insulation	1%	of purchased equip cost (B)	4,718
Painting	1%	of purchased equip cost (B)	4,718
Installation Total	85%		**401,063**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**872,901**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	47,184
Construction & field expenses	10%	of purchased equip cost (B)	47,184
Construction fee	10%	of purchased equip cost (B)	47,184
Start-up	1%	of purchased equip cost (B)	4,718
Performance test	1%	of purchased equip cost (B)	4,718
Contingencies	3%	of purchased equip cost (B)	14,155
Total Indirect Capital Costs, IC	35%		**165,143**
Total Capital Investment (TCI) = DC + IC			**1,038,044**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.00	\$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	11,250
Supervisor	15%	of oper labor costs 15%	1,688
Operating Materials			
Reagent #1	280	\$/Ton, 875.2 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	980,247
Reagent #2	NA	\$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA		-
Wastewater Treatment	1.50	\$/Mgal, 679.9 gpm, 8000 hr/yr, 90.0% of capacity	440,584
Maintenance			
Maintenance Labor	17.50	1/2 hr per shift	8,750
Maintenance Materials	100%	of maintenance labor costs	8,750
Electricity - Fan, Pump	0.05	\$/kW-hr, 1,397 kW-hr, 8000 hr/yr, 90.0% of capacity	462,573
Total Annual Direct Operating Costs			**1,913,842**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	18,263
Administration (2% total capital costs)	2%	of total capital costs (TCI)	20,761
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	10,380
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	10,380
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	147,794
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**2,121,421**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,035,263**
Pollutant Removed (tons/yr)[B]			**1,330**
Cost per ton of SO2 Removed			**3,033**

Notes & Assumptions

3 EPA Air Pollution Control Cost Manual 6th Ed 2002
4
5
6

Table J-13: High Efficiency Wet Scrubber - Grate/Kiln Induration - SO2 (130-ppm) (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	300,000	dscfm	340,909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,000** — **Utilization Rate:** **90.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Op Labor	25	Hr	0.5	hr/8 hr shift	450	11,250	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,688	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	450	4,125	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	1396.7	kW-hr	10,055,941	462,573	$/kW-hr, 1,397 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.2	Mgal	679.9	gpm	293,723	58,745	$/Mgal, 679.9 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	875.22	lb/hr	3,501	980,247	$/Ton, 875.2 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.5	Mgal	679.9	gpm	293,723	440,584	$/Mgal, 679.9 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
130	ppm	300,000	dscfm	NA	**1,400.4**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				95%	**70**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1330.3**	Assuming 95% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	339,957	12	0.55	0.7	1239.7	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	3,400	125	0.8	0.7	142.7	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	679.9	62.5	0.8	0.7	14.3	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	350.09	lb/hr SO2	2.50	lb NaOH/lb SO2	875.22	lb/hr Caustic
Lime Use	350.09	lb/hr SO2	1.53	lb Lime/lb SO2	535.64	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8000 hr/yr, 90.0% of capacity

ATTACHMENT K

Model BART Cost Analysis - Induration Furnace PM Emissions

<u>List of Tables</u>:

MPCA BART Anaylsis 2003

Table K-1: BART Screening Evaluation Summary: Straight Grate Induration - Wet Scrubber, ESP, Wet Wall ESP, Fabric Filters and Multiclones

Model Source for Straight Grate Waste Gas Exhaust - PM Emissions

General Information

Source Type	Straight Grate Waste Gas Exhaust
Pollutant:	Particulate Matter (PM10)
Existing Pollution Control Equipment	Most sources are routed to a wet scrubber

Control Cost Summary

Control Technology	Control Eff %	Emissions T/y	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton	Air Toxic's & AQRV's?	Energy Impacts?	Non-Air Env Impacts?
Wet Scrubbers High Efficiency	**99%**	**41.1**	**40.7**	**572,338**	**1,086,676**	**26,679**	**None**	**Medium**	**Wastewater**
Wet Scrubbers Low Efficiency	**92%**	**41.1**	**37.9**	**572,338**	**1,086,676**	**28,709**	**None**	**Medium**	**Wastewater**
Dry ElectroStatic Precipitators (ESP)	**99%**	**41.1**	**40.7**	**3,675,579**	**701,132**	**17,214**	**None**	**Low**	**Solid Waste**
Wet Wall ElectroStatic Precipitator (WWESP)	**99%**	**41.1**	**40.7**	**3,785,848**	**2,141,976**	**52,588**	**None**	**Low**	**Solid Waste**
Fabric Filters (Baghouses)	**99%**	**41.1**	**40.7**	**2,147,481**	**1,213,453**	**29,792**	**None**	**High**	**Solid Waste**
Multiclones	**80%**	**41.1**	**32.9**	**272,391**	**685,529**	**20,828**	**None**	**High**	**Solid Waste**

Comments

Table K-2: BART Screening Evaluation Summary: Grate/Kiln Induration - Wet Scrubber, ESP, Wet Wall ESP, Fabric Filters and Multiclones

Model Source for Grate/Kiln Waste Gas Exhaust - PM Emissions

General Information

Source Type	Grate/Kiln Waste Gas Exhaust
Pollutant:	Particulate Matter (PM10)
Existing Pollution Control Equipment	Most sources have a wet scrubber or WW ESP

Control Cost Summary

Control Technology	Control Eff %	Emissions T/y	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton	Air Toxic's & AQRV's?	Energy Impacts?	Non-Air Env Impacts?
Wet Scrubbers High Efficiency	99%	514.3	509.1	1,038,044	2,074,768	4,075	None	Medium	Wastewater
Wet Scrubbers Low Efficiency	95%	514.3	488.6	1,038,044	2,074,768	4,247	None	Medium	Wastewater
Dry ElectroStatic Precipitators (ESP)	99%	514.3	509.1	5,835,727	1,137,133	2,233	None	Low	Solid Waste
Wet Wall ElectroStatic Precipitator (WWESP)	99%	514.3	509.1	6,010,799	3,997,767	7,852	None	Low	Wastewater
Fabric Filters (Baghouses)	99%	514.3	509.1	4,294,971	2,289,600	4,497	None	High	Solid Waste
Multiclones	80%	514.3	411.4	533,041	1,333,858	3,242	None	High	Solid Waste

Comments

Table K-3: Low Efficiency Wet Scrubber - Straight Grate Induration - PM
BART Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC		**220,469**
Instrumentation	10% of control device cost (A)	22,047
MN Sales Taxes	3.0% of control device cost (A)	6,614
Freight	5% of control device cost (A)	11,023
Purchased Equipment Total (B)	18%	**260,153**
Installation		
Foundations & supports	12% of purchased equip cost (B)	31,218
Handling & erection	40% of purchased equip cost (B)	104,061
Electrical	1% of purchased equip cost (B)	2,602
Piping	30% of purchased equip cost (B)	78,046
Insulation	1% of purchased equip cost (B)	2,602
Painting	1% of purchased equip cost (B)	2,602
Installation Total	85%	**221,130**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Total Direct Capital Cost, DC		**481,284**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	26,015
Construction & field expenses	10% of purchased equip cost (B)	26,015
Construction fee	10% of purchased equip cost (B)	26,015
Start-up	1% of purchased equip cost (B)	2,602
Performance test	1% of purchased equip cost (B)	2,602
Contingencies	3% of purchased equip cost (B)	7,805
Total Indirect Capital Costs, IC	35%	**91,054**
Total Capital Investment (TCI) = DC + IC		**572,338**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	25.00 $/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	11,250
Supervisor	15% of oper labor costs 15%	1,688
Operating Materials		
Reagent #1	NA $/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	NA $/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA	-
Wastewater Treatment	1.50 $/Mgal, 340.0 gpm, 8000 hr/yr, 90.0% of capacity	220,292
Maintenance		
Maintenance Labor	17.50 1/2 hr per shift	8,750
Maintenance Materials	100% of maintenance labor costs	8,750
Electricity - Fan, Pump	0.05 $/kW-hr, 698 kW-hr, 8000 hr/yr, 90.0% of capacity	231,287
Total Annual Direct Operating Costs		**482,016**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	18,263
Administration (2% total capital costs)	2% of total capital costs (TCI)	11,447
Property tax (1% total capital costs)	1% of total capital costs (TCI)	5,723
Insurance (1% total capital costs)	1% of total capital costs (TCI)	5,723
Capital Recovery	14.24% for a 10- year equipment life and a 7% interest rate	81,488
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**604,660**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**1,086,676**
Pollutant Removed (tons/yr)[B]		**38**
Cost per ton of PM Removed		**28,709**

Notes & Assumptions

1 EPA Air Pollution Control Cost Manual 6th Ed 2002
2
3
4
5
6

Table K-3: Low Efficiency Wet Scrubber - Straight Grate Induration - PM (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	150,000	dscfm	170455	scfm
	135	Temp Deg F		
	12%	% Moisture		
	188,865	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,000**; **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	0.5	hr/8 hr shift	450	11,250	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,688	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	450	4,125	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	698	kW-hr	5,027,971	231,287	$/kW-hr, 698 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	340.0	gpm	146,861	32,309	$/Mgal, 340.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0.000	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0.000	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.008 gr/dscf, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.008 gr/dscf, 8000 hr/yr
WW Treat	1.5	Mgal	340.0	gpm	146,861	220,292	$/Mgal, 340.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.008	gr/dscf	150,000	dscfm	NA	**41**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				92%	3.3	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**37.9**	Assuming 92% control (range 90-95%)

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	169,978	12	0.55	0.7	619.9	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	1,700	125	0.8	0.7	71.3	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	340.0	62.5	0.8	0.7	7.1	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8000 hr/yr, 90.0% of capacity

Table K-4: High Efficiency Wet Scrubber - Straight Grate Induration - PM
BART Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC		**220,469**
Instrumentation	10% of control device cost (A)	22,047
MN Sales Taxes	3.0% of control device cost (A)	6,614
Freight	5% of control device cost (A)	11,023
Purchased Equipment Total (B)	18%	**260,153**
Installation		
Foundations & supports	12% of purchased equip cost (B)	31,218
Handling & erection	40% of purchased equip cost (B)	104,061
Electrical	1% of purchased equip cost (B)	2,602
Piping	30% of purchased equip cost (B)	78,046
Insulation	1% of purchased equip cost (B)	2,602
Painting	1% of purchased equip cost (B)	2,602
Installation Total	85%	**221,130**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Total Direct Capital Cost, DC		**481,284**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	26,015
Construction & field expenses	10% of purchased equip cost (B)	26,015
Construction fee	10% of purchased equip cost (B)	26,015
Start-up	1% of purchased equip cost (B)	2,602
Performance test	1% of purchased equip cost (B)	2,602
Contingencies	3% of purchased equip cost (B)	7,805
Total Indirect Capital Costs, IC	35%	**91,054**
Total Capital Investment (TCI) = DC + IC		**572,338**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	25.00 $/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	11,250
Supervisor	15% of oper labor costs 15%	1,688
Operating Materials		
Reagent #1	NA $/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	NA $/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA	-
Wastewater Treatment	1.50 $/Mgal, 340.0 gpm, 8000 hr/yr, 90.0% of capacity	220,292
Maintenance		
Maintenance Labor	17.50 1/2 hr per shift	8,750
Maintenance Materials	100% of maintenance labor costs	8,750
Electricity - Fan, Pump	0.05 $/kW-hr, 698 kW-hr, 8000 hr/yr, 90.0% of capacity	231,287
Total Annual Direct Operating Costs		**482,016**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	18,263
Administration (2% total capital costs)	2% of total capital costs (TCI)	11,447
Property tax (1% total capital costs)	1% of total capital costs (TCI)	5,723
Insurance (1% total capital costs)	1% of total capital costs (TCI)	5,723
Capital Recovery	14.24% for a 10- year equipment life and a 7% interest rate	81,488
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**604,660**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**1,086,676**
Pollutant Removed (tons/yr)[B]		**41**
Cost per ton of PM Removed		**26,679**

Notes & Assumptions

1 EPA Air Pollution Control Cost Manual 6th Ed 2002
2
3
4
5
6

Table K-4: High Efficiency Wet Scrubber - Straight Grate Induration - PM (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	150,000	dscfm	170455	scfm
	135	Temp Deg F		
	12%	% Moisture		
	188,865	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,000** — **Utilization Rate:** **90.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Op Labor	25	Hr	0.5	hr/8 hr shift	450	11,250	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,688	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	450	4,125	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	698	kW-hr	5,027,971	231,287	$/kW-hr, 698 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	340.0	gpm	146,861	32,309	$/Mgal, 340.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.008 gr/dscf, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.008 gr/dscf, 8000 hr/yr
WW Treat	1.5	Mgal	340.0	gpm	146,861	220,292	$/Mgal, 340.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.008	gr/dscf	150,000	dscfm	NA	**41**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99%	0.4	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**40.7**	Assuming 99% control.

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	169,978	12	0.55	0.7	619.9	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	1,700	125	0.8	0.7	71.3	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	340.0	62.5	0.8	0.7	7.1	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8000 hr/yr, 90.0% of capacity

Table K-5: Low Efficiency Wet Scrubber - Grate/Kiln Induration - PM
BART Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC		**399,863**
Instrumentation	10% of control device cost (A)	39,986
MN Sales Taxes	3.0% of control device cost (A)	11,996
Freight	5% of control device cost (A)	19,993
Purchased Equipment Total (B)	18%	**471,838**
Installation		
Foundations & supports	12% of purchased equip cost (B)	56,621
Handling & erection	40% of purchased equip cost (B)	188,735
Electrical	1% of purchased equip cost (B)	4,718
Piping	30% of purchased equip cost (B)	141,552
Insulation	1% of purchased equip cost (B)	4,718
Painting	1% of purchased equip cost (B)	4,718
Installation Total	85%	**401,063**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Total Direct Capital Cost, DC		**872,901**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	47,184
Construction & field expenses	10% of purchased equip cost (B)	47,184
Construction fee	10% of purchased equip cost (B)	47,184
Start-up	1% of purchased equip cost (B)	4,718
Performance test	1% of purchased equip cost (B)	4,718
Contingencies	3% of purchased equip cost (B)	14,155
Total Indirect Capital Costs, IC	35%	**165,143**
Total Capital Investment (TCI) = DC + IC		**1,038,044**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	25.00 $/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	11,250
Supervisor	15% of oper labor costs 15%	1,688
Operating Materials		
Reagent #1	NA $/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	NA	-
Catalyst	NA	-
Wastewater Treatment	1.50 $/Mgal, 679.9 gpm, 8000 hr/yr, 90.0% of capacity	440,584
Maintenance		
Maintenance Labor	17.50 1/2 hr per shift	8,750
Maintenance Materials	100% of maintenance labor costs	8,750
Electricity - Fan, Pump	0.05 $/kW-hr, 1,397 kW-hr, 8000 hr/yr, 90.0% of capacity	462,573
Total Annual Direct Operating Costs		**933,595**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	18,263
Administration (2% total capital costs)	2% of total capital costs (TCI)	20,761
Property tax (1% total capital costs)	1% of total capital costs (TCI)	10,380
Insurance (1% total capital costs)	1% of total capital costs (TCI)	10,380
Capital Recovery	14.24% for a 10- year equipment life and a 7% interest rate	147,794
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**1,141,173**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**2,074,768**
Pollutant Removed (tons/yr)[B]		**489**
Cost per ton of PM Removed		**4,247**

Notes & Assumptions

1 1 EPA Air Pollution Control Cost Manual 6th Ed 2002
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Table K-5: Low Efficiency Wet Scrubber - Grate/Kiln Induration - PM (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	300,000	dscfm	340,909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,000** — **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	0.5	hr/8 hr shift	450	11,250	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,688	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	450	4,125	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	1397	kW-hr	10,055,941	462,573	$/kW-hr, 1,397 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	679.9	gpm	293,723	64,619	$/Mgal, 679.9 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.050 gr/dscf, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.050 gr/dscf, 8000 hr/yr
WW Treat	1.5	Mgal	679.9	gpm	293,723	440,584	$/Mgal, 679.9 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.05	gr/dscf	300,000	dscfm	NA	**514.3**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				95%	**26**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**488.6**	Assuming 92% control (range 90-95%)

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	339,957	12	0.55	0.7	1239.7	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	3,400	125	0.8	0.7	142.7	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	679.9	62.5	0.8	0.7	14.3	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8000 hr/yr, 90.0% of capacity

Table K-6: High Efficiency Wet Scrubber - Grate/Kiln Induration - PM
BART Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**399,863**
Instrumentation	10%	of control device cost (A)	39,986
MN Sales Taxes	3.0%	of control device cost (A)	11,996
Freight	5%	of control device cost (A)	19,993
Purchased Equipment Total (B)	18%		**471,838**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	56,621
Handling & erection	40%	of purchased equip cost (B)	188,735
Electrical	1%	of purchased equip cost (B)	4,718
Piping	30%	of purchased equip cost (B)	141,552
Insulation	1%	of purchased equip cost (B)	4,718
Painting	1%	of purchased equip cost (B)	4,718
Installation Total	85%		**401,063**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**872,901**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	47,184
Construction & field expenses	10%	of purchased equip cost (B)	47,184
Construction fee	10%	of purchased equip cost (B)	47,184
Start-up	1%	of purchased equip cost (B)	4,718
Performance test	1%	of purchased equip cost (B)	4,718
Contingencies	3%	of purchased equip cost (B)	14,155
Total Indirect Capital Costs, IC	35%		**165,143**
Total Capital Investment (TCI) = DC + IC			**1,038,044**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.00	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	11,250
Supervisor	15%	of oper labor costs 15%	1,688
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	NA	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA		-
Wastewater Treatment	1.50	$/Mgal, 679.9 gpm, 8000 hr/yr, 90.0% of capacity	440,584
Maintenance			
Maintenance Labor	17.50	1/2 hr per shift	8,750
Maintenance Materials	100%	of maintenance labor costs	8,750
Electricity - Fan, Pump	0.05	$/kW-hr, 1,397 kW-hr, 8000 hr/yr, 90.0% of capacity	462,573
Total Annual Direct Operating Costs			**933,595**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	18,263
Administration (2% total capital costs)	2%	of total capital costs (TCI)	20,761
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	10,380
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	10,380
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	147,794
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,141,173**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,074,768**
Pollutant Removed (tons/yr)[B]			**509**
Cost per ton of PM Removed			**4,075**

Notes & Assumptions

1 1 EPA Air Pollution Control Cost Manual 6th Ed 2002
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Table K-6: High Efficiency Wet Scrubber - Grate/Kiln Induration - PM (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	300,000	dscfm	340,909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,000** — **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	0.5	hr/8 hr shift	450	11,250	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,688	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	450	4,125	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	1397	kW-hr	10,055,941	462,573	$/kW-hr, 1,397 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	679.9	gpm	293,723	64,619	$/Mgal, 679.9 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.050 gr/dscf, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.050 gr/dscf, 8000 hr/yr
WW Treat	1.5	Mgal	679.9	gpm	293,723	440,584	$/Mgal, 679.9 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.05	gr/dscf	300,000	dscfm	NA	**514.3**	

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99%	**5**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**509.1**	Assuming 99% control.

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	339,957	12	0.55	0.7	1239.7	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	3,400	125	0.8	0.7	142.7	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	679.9	62.5	0.8	0.7	14.3	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8000 hr/yr, 90.0% of capacity

Table K-7: ESP - Straight Grate Induration - PM
BACT Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**1,396,815**
Instrumentation	10%	of control device cost (A)	139,682
MN Sales Taxes	3%	of control device cost (A)	41,904
Freight	5%	of control device cost (A)	69,841
Purchased Equipment Total (B)	18%		**1,648,242**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	65,930
Handling & erection	50%	of purchased equip cost (B)	824,121
Electrical	8%	of purchased equip cost (B)	131,859
Piping	1%	of purchased equip cost (B)	16,482
Insulation for ductwork	2%	of purchased equip cost (B)	32,965
Painting	2%	of purchased equip cost (B)	32,965
Direct Installation Costs			**1,104,322**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**2,752,564**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	329,648
Construction & field expenses	20%	of purchased equip cost (B)	329,648
Constractor fees	10%	of purchased equip cost (B)	164,824
Start-up	1%	of purchased equip cost (B)	16,482
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	32,965
Contingencies	3%	of purchased equip cost (B)	49,447
Total Indirect Capital Costs	57%		**923,015**
Total Capital Investment (TCI) = DC + IC			**3,675,579**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.00	$/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	25,000
Supervisor	15%	of operator costs	3,750
Coordinator	33%	of operator costs	8,250
Operating materials			
Maintenance Labor	0.1155	$/ft2 collector area; $5775 if < 50,000 ft2	18,093
Maintenance Materials	1%	of purchased equipment costs	16,482
Utilities			
Electricity	0.05	$/kW-hr, 262.4 kW-hr, 8000 hr/yr, 90.0% of capacity	96,571
Water	NA		-
Solid Waste Disposal	25.00	$/Ton, 0.008 gr/dscf, 8000 hr/yr	1,018
Wastewater Treatment	NA		-
Total Annual Direct Operating Costs, DC			**169,165**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	37,995
Administration (2% total capital costs)	2%	of total capital costs (TCI)	73,512
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	36,756
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	36,756
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	346,949
Total Indirect Operating Costs			**531,967**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**701,132**
Pollutant Removed (tons/yr)[B]			**40.7**
Cost per ton of PM Removed			**17,214**

Notes & Assumptions

1 EPA Cost Manual 6th Ed. 2002
2 Cost estimates based on 2001 ESP cost curve data.
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Table K-7: ESP - Straight Grate Induration - PM (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	150,000	dscfm	170455	scfm
	135	Temp Deg F		
	12%	% Moisture		
	188,865	acfm		

Operating Cost Calculations — **Annual hours of operation: 8,000** — **Utilization Rate: 90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	1	hr/8 hr shift	1,000	25,000	$/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.1155	$/ft^2 collector	45,589	ft^2 collector area		4,125	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	262	kW-hr	2,099,368	96,571	$/kW-hr, 262.4 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0.0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25	Ton	0.005	ton/hr	41	1,018	$/Ton, 0.008 gr/dscf, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.008 gr/dscf, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.008	gr/dscf	150,000	dscfm	NA	**41.14**	

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99%	**0.4**	Currently assumes 99%.
Emission Reduction T/yr					**40.7**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower Eff		kW	
Blower	188,865	5	0.65		170.0	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	45,589	88.4	2	4	92.4	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Estimate Area (ft2)		
Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	150,000	acfm
Area #2	**45589.0**	**ft2**

Table K-8: ESP - Grate/Kiln Induration - PM
BACT Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
ESP + auxillary equipment		**2,217,727**
Instrumentation	10% of control device cost (A)	221,773
MN Sales Taxes	3% of control device cost (A)	66,532
Freight	5% of control device cost (A)	110,886
Purchased Equipment Total (B)	18%	**2,616,918**
Direct Installation Costs		
Foundations & supports	4% of purchased equip cost (B)	104,677
Handling & erection	50% of purchased equip cost (B)	1,308,459
Electrical	8% of purchased equip cost (B)	209,353
Piping	1% of purchased equip cost (B)	26,169
Insulation for ductwork	2% of purchased equip cost (B)	52,338
Painting	2% of purchased equip cost (B)	52,338
Direct Installation Costs		**1,753,335**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Total Direct Capital Costs, DC	67%	**4,370,253**
Indirect Capital Costs		
Engineering	20% of purchased equip cost (B)	523,384
Construction & field expenses	20% of purchased equip cost (B)	523,384
Constractor fees	10% of purchased equip cost (B)	261,692
Start-up	1% of purchased equip cost (B)	26,169
Performance Test	1% of purchased equip cost (B)	
Model Study	2% of purchased equip cost (B)	52,338
Contingencies	3% of purchased equip cost (B)	78,508
Total Indirect Capital Costs	57%	**1,465,474**
Total Capital Investment (TCI) = DC + IC		**5,835,727**
OPERATING COSTS		
Direct Operating Costs		
Operator	25.00 $/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	25,000
Supervisor	15% of operator costs	3,750
Coordinator	33% of operator costs	8,250
Operating materials		
Maintenance Labor	0.1155 $/ft2 collector area; $5775 if < 50,000 ft2	32,708
Maintenance Materials	1% of purchased equipment costs	26,169
Utilities		
Electricity	0.05 $/kW-hr, 520.8 kW-hr, 8000 hr/yr, 90.0% of capacity	191,670
Water	NA	-
Solid Waste Disposal	25.00 $/Ton, 0.050 gr/dscf, 8000 hr/yr	12,729
Wastewater Treatment	NA	-
Total Annual Direct Operating Costs, DC		**300,276**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	52,576
Administration (2% total capital costs)	2% of total capital costs (TCI)	116,715
Property tax (1% total capital costs)	1% of total capital costs (TCI)	58,357
Insurance (1% total capital costs)	1% of total capital costs (TCI)	58,357
Captial Recovery	9% for a 20- year equipment life and a 7% interest rate	550,851
Total Indirect Operating Costs		**836,857**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**1,137,133**
Pollutant Removed (tons/yr)[B]		**509.1**
Cost per ton of PM Removed		**2,233**

Notes & Assumptions

1 EPA Cost Manual 6th Ed. 2002
2 Cost estimates based on 2001 ESP cost curve data.
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Table K-8: ESP - Grate/Kiln Induration - PM (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	300,000	dscfm	340909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations				**Annual hours of operation:**	**8,000**		
				Utilization Rate:		**90.0%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	1	hr/8 hr shift	1,000	25,000	$/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.1155	$/ft^2 collector	91,178	ft^2 collector area		10,531	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	521	kW-hr	4,166,736	191,670	$/kW-hr, 520.8 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0.0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25	Ton	0.064	ton/hr	509	12,729	$/Ton, 0.050 gr/dscf, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.050 gr/dscf, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.05	gr/dscf	300,000	dscfm	NA	**514.29**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99%	**5.1**	Currently assumes 99%.
Emission Reduction T/yr					**509.1**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower Eff		kW	
Blower	377,730	5	0.65		340.0	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	91,178	176.9	2	4	180.9	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Estimate Area (ft2)		
Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	300,000	acfm
Area #2	**91177.9**	**ft2**

Table K-9: Wet Wall ESP - Straight Grate Induration - PM
BACT Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
ESP + auxillary equipment		**1,438,720**
Instrumentation	10% of control device cost (A)	143,872
MN Sales Taxes	3% of control device cost (A)	43,162
Freight	5% of control device cost (A)	71,936
Purchased Equipment Total (B)	18%	**1,697,690**
Direct Installation Costs		
Foundations & supports	4% of purchased equip cost (B)	67,908
Handling & erection	50% of purchased equip cost (B)	848,845
Electrical	8% of purchased equip cost (B)	135,815
Piping	1% of purchased equip cost (B)	16,977
Insulation for ductwork	2% of purchased equip cost (B)	33,954
Painting	2% of purchased equip cost (B)	33,954
Direct Installation Costs		**1,137,452**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Total Direct Capital Costs, DC	67%	**2,835,142**
Indirect Capital Costs		
Engineering	20% of purchased equip cost (B)	339,538
Construction & field expenses	20% of purchased equip cost (B)	339,538
Constractor fees	10% of purchased equip cost (B)	169,769
Start-up	1% of purchased equip cost (B)	16,977
Performance Test	1% of purchased equip cost (B)	
Model Study	2% of purchased equip cost (B)	33,954
Contingencies	3% of purchased equip cost (B)	50,931
Total Indirect Capital Costs	57%	**950,706**
Total Capital Investment (TCI) = DC + IC		**3,785,848**
OPERATING COSTS		
Direct Operating Costs		
Operator	25.00 $/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	25,000
Supervisor	15% of operator costs	3,750
Coordinator	33% of operator costs	8,250
Operating materials		
Maintenance Labor	0.1155 $/ft2 collector area; $5775 if < 50,000 ft2	21,017
Maintenance Materials	1% of purchased equipment costs	16,977
Utilities		
Electricity	0.05 $/kW-hr, 312.0 kW-hr, 8000 hr/yr, 90.0% of capacity	114,803
Water	0.22 $/Mgal, 1,699.8 gpm, 8000 hr/yr, 90.0% of capacity	179,497
Solid Waste Disposal	NA	-
Wastewater Treatment	1.50 $/Mgal, 1,699.8 gpm, 8000 hr/yr, 90.0% of capacity	1,223,845
Reagent (Caustic)	280.00 $/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Total Annual Direct Operating Costs, DC		**1,593,139**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	40,046
Administration (2% total capital costs)	2% of total capital costs (TCI)	75,717
Property tax (1% total capital costs)	1% of total capital costs (TCI)	37,858
Insurance (1% total capital costs)	1% of total capital costs (TCI)	37,858
Captial Recovery	9% for a 20- year equipment life and a 7% interest rate	357,357
Total Indirect Operating Costs		**548,838**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**2,141,976**
Pollutant Removed (tons/yr)[B]		**40.7**
Cost per ton of PM Removed		**52,588**

Notes & Assumptions

1 Equipment cost estimates assumed to be 3% higher than that of dry ESP.
2 EPA Cost Manual 6th Ed. 2002
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Table K-9: Wet Wall ESP - Straight Grate Induration - PM (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	150,000	dscfm	170455	scfm
	135	Temp Deg F		
	12%	% Moisture		
	188,865	acfm		

Operating Cost Calculations — **Annual hours of operation: 8,000** — **Utilization Rate: 90.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Op Labor	25	Hr	1	hr/8 hr shift	1,000	25,000	$/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.1155	$/ft^2 collector	57,401	ft^2 collector area		6,630	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	312	kW-hr	2,495,722	114,803	$/kW-hr, 312.0 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	1700	gpm	815,896	179,497	$/Mgal, 1,699.8 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.008 gr/dscf, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.008 gr/dscf, 8000 hr/yr
WW Treat	1.5	Mgal	1700	gpm	815,896	1,223,845	$/Mgal, 1,699.8 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	Unit of Measure	Flow Rate	Unit of Measure	Control Eff. %	Emis Rate T/yr	Comments/Notes
0.008	gr/dscf	150,000	dscfm	NA	**41.14**	

Controlled Emission Rate

Perf Guarantee	Unit of Measure	Flow Rate	Unit of Measure	Control Eff. %	Emis Rate T/yr	Comments/Notes
				99%	**0.4**	Currently assumes 99%.
Emission Reduction T/yr					**40.7**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	D P in H2O	Blower-Motor Eff			
Blower	188,865	5	0.65		170.0	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	1700	60	0.8	0.9	26.6	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	0	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	57,401	111.4	2	4	115.4	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Caustic Use	10.29	lb/hr SO2	2.50	lb NaOH/lb SO2	0.013	T/hr Caustic
Lime Use	10.29	lb/hr SO2	1.53	lb Lime/lb SO2	0.008	T/hr Lime

Estimate Area (ft2)

Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	188,865	acfm
Area #2	**57401.0**	**ft2**

Table K-10: Wet Wall ESP - Grate/Kiln Induration - PM
BACT Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**2,284,259**
Instrumentation	10%	of control device cost (A)	228,426
MN Sales Taxes	3%	of control device cost (A)	68,528
Freight	5%	of control device cost (A)	114,213
Purchased Equipment Total (B)	18%		**2,695,426**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	107,817
Handling & erection	50%	of purchased equip cost (B)	1,347,713
Electrical	8%	of purchased equip cost (B)	215,634
Piping	1%	of purchased equip cost (B)	26,954
Insulation for ductwork	2%	of purchased equip cost (B)	53,909
Painting	2%	of purchased equip cost (B)	53,909
Direct Installation Costs			**1,805,935**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**4,501,361**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	539,085
Construction & field expenses	20%	of purchased equip cost (B)	539,085
Constractor fees	10%	of purchased equip cost (B)	269,543
Start-up	1%	of purchased equip cost (B)	26,954
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	53,909
Contingencies	3%	of purchased equip cost (B)	80,863
Total Indirect Capital Costs	57%		**1,509,438**
Total Capital Investment (TCI) = DC + IC			**6,010,799**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.00	$/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	25,000
Supervisor	15%	of operator costs	3,750
Coordinator	33%	of operator costs	8,250
Operating materials			
Maintenance Labor	0.1155	$/ft2 collector area; $5775 if < 50,000 ft2	36,102
Maintenance Materials	1%	of purchased equipment costs	26,954
Utilities			
Electricity	0.05	$/kW-hr, 619.9 kW-hr, 8000 hr/yr, 90.0% of capacity	228,134
Water	0.22	$/Mgal, 3,399.6 gpm, 8000 hr/yr, 90.0% of capacity	358,994
Solid Waste Disposal	NA		-
Wastewater Treatment	1.50	$/Mgal, 3,399.6 gpm, 8000 hr/yr, 90.0% of capacity	2,447,689
Reagent (Caustic)	280.00	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Total Annual Direct Operating Costs, DC			**3,134,874**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,084
Administration (2% total capital costs)	2%	of total capital costs (TCI)	120,216
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	60,108
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	60,108
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	567,377
Total Indirect Operating Costs, IC			**862,893**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**3,997,767**
Pollutant Removed (tons/yr)[B]			**509.1**
Cost per ton of PM Removed			**7,852**

Notes & Assumptions

1 Equipment cost estimates assumed to be 3% higher than that of dry ESP.
2 EPA Cost Manual 6th Ed. 2002
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Table K-10: Wet Wall ESP - Grate/Kiln Induration - PM (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	300,000	dscfm	340909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations					**Annual hours of operation:**		**8,000**	
					Utilization Rate:		**90.0%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**	
Op Labor	25	Hr	1	hr/8 hr shift	1,000	25,000	$/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	
Supervisor	NA				NA	NA	Calc'd as % of labor costs	
Maint Labor	0.1155	$/ft^2 collector	114,802	ft^2 collector area		13,260	$/ft^2 collector area; $5775 if < 50,000 ft^2	
Maint Mtls	NA				NA	1%	of purchased equipment costs	
Utilities, Reagents, Waste Management & Replacements								
Electricity	0.046	kW-hr	620	kW-hr	4,959,444	228,134	$/kW-hr, 619.9 kW-hr, 8000 hr/yr, 90.0% of capacity	
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity	
Water	0.22	Mgal	3400	gpm	1,631,793	358,994	$/Mgal, 3,399.6 gpm, 8000 hr/yr, 90.0% of capacity	
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity	
Reagent #1(Caustic)	280	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.050 gr/dscf, 8000 hr/yr	
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.050 gr/dscf, 8000 hr/yr	
WW Treat	1.5	Mgal	3400	gpm	1,631,793	2,447,689	$/Mgal, 3,399.6 gpm, 8000 hr/yr, 90.0% of capacity	
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity	
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity	

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.05	gr/dscf	300,000	dscfm	NA	**514.29**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99%	**5.1**	Currently assumes 99%.
Emission Reduction T/yr					**509.1**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff		kW	
Blower	377,730	5	0.65		340.0	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	3400	60	0.8	0.9	53.3	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	0	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	114,802	222.7	2	4	226.7	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Caustic Use	128.57	lb/hr SO2	2.50	lb NaOH/lb SO2	0.161	T/hr Caustic
Lime Use	128.57	lb/hr SO2	1.53	lb Lime/lb SO2	0.098	T/hr Lime

Estimate Area (ft2)

Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	377,730	acfm
Area #2	**114802.0**	**ft2**

Table K-11: Baghouse - Straight Grate Induration - PM
BACT Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Fabric Filter (EC) + bags + auxillary equipment		**831,004**
Instrumentation	10% of control device cost (A)	83,100
MN Sales Taxes	3% of control device cost (A)	24,930
Freight	5% of control device cost (A)	41,550
Purchased Equipment Total (B)	18%	**980,585**
Direct installation costs		
Foundations & supports	4% of purchased equip cost (B)	39,223
Handling & erection	50% of purchased equip cost (B)	490,292
Electrical	8% of purchased equip cost (B)	78,447
Piping	1% of purchased equip cost (B)	9,806
Insulation for ductwork	7% of purchased equip cost (B)	68,641
Painting	4% of purchased equip cost (B)	39,223
Installation Total	74%	**725,633**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Total Direct Capital Cost		**1,706,217**
Indirect Capital Costs		
Engineering	10% of purchased equip cost (B)	98,058
Construction and field expense	20% of purchased equip cost (B)	196,117
Contractor fees	10% of purchased equip cost (B)	98,058
Startup	1% of purchased equip cost (B)	9,806
Performance test	1% of purchased equip cost (B)	9,806
Contingencies	3% of purchased equip cost (B)	29,418
Total Indirect Capital Costs	45%	**441,263**
Total Capital Investment (TCI) = DC + IC		**2,147,481**
OPERATING COSTS		
Direct Operating Costs		
Operating Labor	25.00 $/Hr, 2.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	50,000
Supervisor	15% of operator labor costs	7,500
Maintenance Labor	17.50 $/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	17,500
Maintenance Materials	100% of maintenance labor costs	17,500
Replacement parts, bags		123,039
Utilities		
Electricity	0.05 $/kW-hr, 1,640.9 kW-hr, 8000 hr/yr, 90.0% of capacity	603,836
Compressed Air	0.27 $/Mscf, 377.7 Mscfm, 8000 hr/yr, 90.0% of capacity	48,954
Solid Waste Disposal	25.00 $/Ton, 0.008 gr/dscf, 8000 hr/yr	1,018
Total Annual Direct Operating Costs (DC)		**869,347**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	55,500
Administration (2% total capital costs)	2% of total capital costs (TCI)	42,950
Property tax (1% total capital costs)	1% of total capital costs (TCI)	21,475
Insurance (1% total capital costs)	1% of total capital costs (TCI)	21,475
Capital Recovery	9% for a 20- year equipment life and a 7% interest rate	202,707
Total Indirect Operating Costs		**344,106**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**1,213,453**
Pollutant Removed (tons/yr)[B]		**41**
Cost per ton of PM Removed		**29,792**

Notes & Assumptions

1 1 EPA Cost Manual 6th Ed. 2002
2
3
4
5
6
7
8

Table K-11: Baghouse - Straight Grate Induration - PM (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35	$ each
Amount Required	3,022	Number
Total Rep Parts Cost	114,225	Cost adjusted for freight & sales tax
Installation Labor	8,814	10 min per bag Labor at $17.50/hr
Total Installed Cost	**123,039**	
Annualized Cost	**68,052**	

Total Cost Replacement Parts (Bags) **123,039**

Design Flow	150,000	dscfm	170455	scfm
	135	Temp Deg F		
	12%	% Moisture		
	188,865	acfm		

Operating Cost Calculations				**Annual hours of operation:**		**8,000**	
				Utilization Rate:		**90.0%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	2	hr/8 hr shift	2,000	50,000	$/Hr, 2.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.5	Hr	1	hr/8 hr shift	1,000	17,500	$/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	1641	kW-hr	13,126,866	603,836	$/kW-hr, 1,640.9 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	377.73	Mscfm	181,310	48,954	$/Mscf, 377.7 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25	Ton	0.005	ton/hr	41	1,018	$/Ton, 0.008 gr/dscf, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.008 gr/dscf, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	35	bag	3021.838497	bags	2 yr life	68,052	$/bag, 3,021.8 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.008	gr/dscf	150,000	dscfm	NA	**41**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99%	**0.4**	Currently assumes 99%.
Emission Reduction T/yr					**41**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	188,865	6	0.65	1640.9	OAQPS Cost Cont Manual 6th ed - Eq 1.14

Table K-12: Baghouse - Grate/Kiln Induration - PM
BACT Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Fabric Filter (EC) + bags + auxillary equipment		**1,662,012**
Instrumentation	10% of control device cost (A)	166,201
MN Sales Taxes	3% of control device cost (A)	49,860
Freight	5% of control device cost (A)	83,101
Purchased Equipment Total (B)	18%	**1,961,174**
Direct installation costs		
Foundations & supports	4% of purchased equip cost (B)	78,447
Handling & erection	50% of purchased equip cost (B)	980,587
Electrical	8% of purchased equip cost (B)	156,894
Piping	1% of purchased equip cost (B)	19,612
Insulation for ductwork	7% of purchased equip cost (B)	137,282
Painting	4% of purchased equip cost (B)	78,447
Installation Total	74%	**1,451,269**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Total Direct Capital Cost		**3,412,443**
Indirect Capital Costs		
Engineering	10% of purchased equip cost (B)	196,117
Construction and field expense	20% of purchased equip cost (B)	392,235
Contractor fees	10% of purchased equip cost (B)	196,117
Startup	1% of purchased equip cost (B)	19,612
Performance test	1% of purchased equip cost (B)	19,612
Contingencies	3% of purchased equip cost (B)	58,835
Total Indirect Capital Costs	45%	**882,528**
Total Capital Investment (TCI) = DC + IC		**4,294,971**
OPERATING COSTS		
Direct Operating Costs		
Operating Labor	25.00 $/Hr, 2.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	50,000
Supervisor	15% of operator labor costs	7,500
Maintenance Labor	17.50 $/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	17,500
Maintenance Materials	100% of maintenance labor costs	17,500
Replacement parts, bags		246,078
Utilities		
Electricity	0.05 $/kW-hr, 3,281.7 kW-hr, 8000 hr/yr, 90.0% of capacity	1,207,672
Compressed Air	0.27 $/Mscf, 755.5 Mscfm, 8000 hr/yr, 90.0% of capacity	97,908
Solid Waste Disposal	25.00 $/Ton, 0.050 gr/dscf, 8000 hr/yr	12,729
Total Annual Direct Operating Costs (DC)		**1,656,886**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	55,500
Administration (2% total capital costs)	2% of total capital costs (TCI)	85,899
Property tax (1% total capital costs)	1% of total capital costs (TCI)	42,950
Insurance (1% total capital costs)	1% of total capital costs (TCI)	42,950
Capital Recovery	9% for a 20- year equipment life and a 7% interest rate	405,415
Total Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**632,714**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**2,289,600**
Pollutant Removed (tons/yr)[B]		**509**
Cost per ton of PM Removed		**4,497**

Notes & Assumptions

1 1 EPA Cost Manual 6th Ed. 2002
2
3
4
5
6
7
8

Table K-12: Baghouse - Grate/Kiln Induration - PM (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35	$ each
Amount Required	6043.67699	Number
Total Rep Parts Cost	228,451	Cost adjusted for freight & sales tax
Installation Labor	17,627	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**246,078**	
Annualized Cost	**136,104**	

Total Cost Replacement Parts (Bags) **246,078**

Design Flow	300,000	dscfm	340909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations				**Annual hours of operation:**		**8,000**	
				Utilization Rate:		**90.0%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	2	hr/8 hr shift	2,000	50,000	$/Hr, 2.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.5	Hr	1	hr/8 hr shift	1,000	17,500	$/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	3282	kW-hr	26,253,733	1,207,672	$/kW-hr, 3,281.7 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	755.46	Mscfm	362,621	97,908	$/Mscf, 755.5 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25	Ton	0.064	ton/hr	509	12,729	$/Ton, 0.050 gr/dscf, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.050 gr/dscf, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	35	bag	6043.67699	bags	2 yr life	136,104	$/bag, 6,043.7 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.05	gr/dscf	300,000	dscfm	NA	**514**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99%	**5.1**	Currently assumes 99%.
Emission Reduction T/yr					**509**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	377,730	6	0.65	3281.7	OAQPS Cost Cont Manual 6th ed - Eq 1.14

Table K-13: Multiclone - Straight Grate Induration - PM
BACT Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Fabric Filter (EC) + bags + auxillary equipment			**116,000**
Instrumentation	10%	of control device cost (A)	11,600
MN Sales Taxes	3%	of control device cost (A)	3,480
Freight	5%	of control device cost (A)	5,800
Purchased Equipment Total (B)	18%		**136,880**
Direct installation costs			
Foundations & supports	4%	of purchased equip cost (B)	5,475
Handling & erection	40%	of purchased equip cost (B)	54,752
Electrical	8%	of purchased equip cost (B)	10,950
Piping	1%	of purchased equip cost (B)	1,369
Insulation for ductwork	7%	of purchased equip cost (B)	9,582
Painting	4%	of purchased equip cost (B)	5,475
Installation Total	74%		**87,603**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost			**224,483**
Indirect Capital Costs			
Engineering	10%	of purchased equip cost (B)	13,688
Construction and field expense	10%	of purchased equip cost (B)	13,688
Contractor fees	10%	of purchased equip cost (B)	13,688
Startup	1%	of purchased equip cost (B)	1,369
Performance test	1%	of purchased equip cost (B)	1,369
Contingencies	3%	of purchased equip cost (B)	4,106
Total Indirect Capital Costs	45%		**47,908**
Total Capital Investment (TCI) = DC + IC			**272,391**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	17.26	\$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	8,630
Supervisor	15%	of operator labor costs	1,295
Maintenance Labor	17.74	\$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	8,870
Maintenance Materials	100%	of maintenance labor costs	8,870
Replacement parts, bags			0
Utilities			
Electricity	0.05	\$/kW-hr, 1,640.9 kW-hr, 8000 hr/yr, 90.0% of capacity	603,836
Compressed Air	NA		-
Solid Waste Disposal	25.00	\$/Ton, 0.008 gr/dscf, 8000 hr/yr	823
Total Annual Direct Operating Costs (DC)			**632,323**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	16,599
Administration (2% total capital costs)	2%	of total capital costs (TCI)	5,448
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	2,724
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	2,724
Capital Recovery	9%	for a 20- year equipment life and a 7% interest rate	25,712
Total Indirect Operating Costs			**53,206**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**685,529**
Pollutant Removed (tons/yr)[B]			**33**
Cost per ton of PM Removed			**20,828**

Notes & Assumptions

1 1 EPA Cost Manual 6th Ed. 2002
2 Equipment cost estimates provided by Allen-Sherman-Hoff, July 2003.
3 Equipment cost estimated using 0.6 Power factor in conjunction with multiclone quote provided by Allen-Sherman-Hoff.
4 Reduced erection to 40% and Const Field Exp to 10% to address simpler installation.
5 Reduced operator and maintenance hours to address simpler operation.
6
7
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Table K-13: Multiclone - Straight Grate Induration - PM (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	0	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	150,000	dscfm	170455	scfm
	135	Temp Deg F		
	12%	% Moisture		
	188,865	acfm		

Operating Cost Calculations — **Annual hours of operation: 8,000** — **Utilization Rate: 90.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Op Labor	17.26	Hr	0.5	hr/8 hr shift	500	8,630	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.74	Hr	0.5	hr/8 hr shift	500	8,870	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	1641	kW-hr	13,126,866	603,836	$/kW-hr, 1,640.9 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25	Ton	0.004	ton/hr	33	823	$/Ton, 0.008 gr/dscf, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.008 gr/dscf, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	Unit of Measure	Flow Rate	Unit of Measure	Control Eff. %	Emis Rate T/yr	Comments/Notes
0.008	gr/dscf	150,000	dscfm	NA	**41**	

Controlled Emission Rate

Perf Guarantee	Unit of Measure	Flow Rate	Unit of Measure	Control Eff. %	Emis Rate T/yr	Comments/Notes
				80%	**8**	Currently assumes 80%.
Emission Reduction T/yr					**33**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	188,865	6	0.65	1640.9	OAQPS Cost Cont Manual 6th ed - Eq 1.14

Table K-14: Multiclone - Grate/Kiln Induration - PM
BACT Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Fabric Filter (EC) + bags + auxillary equipment			**227,000**
Instrumentation	10%	of control device cost (A)	22,700
MN Sales Taxes	3%	of control device cost (A)	6,810
Freight	5%	of control device cost (A)	11,350
Purchased Equipment Total (B)	18%		**267,860**
Direct installation costs			
Foundations & supports	4%	of purchased equip cost (B)	10,714
Handling & erection	40%	of purchased equip cost (B)	107,144
Electrical	8%	of purchased equip cost (B)	21,429
Piping	1%	of purchased equip cost (B)	2,679
Insulation for ductwork	7%	of purchased equip cost (B)	18,750
Painting	4%	of purchased equip cost (B)	10,714
Installation Total	74%		**171,430**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost			**439,290**
Indirect Capital Costs			
Engineering	10%	of purchased equip cost (B)	26,786
Construction and field expense	10%	of purchased equip cost (B)	26,786
Contractor fees	10%	of purchased equip cost (B)	26,786
Startup	1%	of purchased equip cost (B)	2,679
Performance test	1%	of purchased equip cost (B)	2,679
Contingencies	3%	of purchased equip cost (B)	8,036
Total Indirect Capital Costs	45%		**93,751**
Total Capital Investment (TCI) = DC + IC			**533,041**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	17.26	\$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	8,630
Supervisor	15%	of operator labor costs	1,295
Maintenance Labor	17.74	\$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	8,870
Maintenance Materials	100%	of maintenance labor costs	8,870
Replacement parts, bags			0
Utilities			
Electricity	0.05	\$/kW-hr, 3,281.7 kW-hr, 8000 hr/yr, 90.0% of capacity	1,207,672
Compressed Air	NA		-
Solid Waste Disposal	25.00	\$/Ton, 0.050 gr/dscf, 8000 hr/yr	10,286
Total Annual Direct Operating Costs (DC)			**1,245,622**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	16,599
Administration (2% total capital costs)	2%	of total capital costs (TCI)	10,661
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	5,330
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	5,330
Capital Recovery	9%	for a 20- year equipment life and a 7% interest rate	50,315
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**88,236**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,333,858**
Pollutant Removed (tons/yr)[B]			**411**
Cost per ton of PM Removed			**3,242**

Notes & Assumptions

1 1 EPA Cost Manual 6th Ed. 2002
2 Equipment cost estimates provided by Allen-Sherman-Hoff, July 2003.
3 Equipment cost estimated using 0.6 Power factor in conjunction with multiclone quote provided by Allen-Sherman-Hoff.
4 Reduced erection to 40% and Const Field Exp to 10% to address simpler installation.
5 Reduced operator and maintenance hours to address simpler operation.
7
8

Table K-14: Multiclone - Grate/Kiln Induration - PM (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	0	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	300,000	dscfm	340909	scfm
	135	Temp Deg F		
	12%	% Moisture		
	377,730	acfm		

Operating Cost Calculations				**Annual hours of operation:**		**8,000**	
				Utilization Rate:		**90.0%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	17.26	Hr	0.5	hr/8 hr shift	500	8,630	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.74	Hr	0.5	hr/8 hr shift	500	8,870	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	3282	kW-hr	26,253,733	1,207,672	$/kW-hr, 3,281.7 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25	Ton	0.051	ton/hr	411	10,286	$/Ton, 0.050 gr/dscf, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.050 gr/dscf, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation						
Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.05	gr/dscf	300,000	dscfm	NA	**514**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				80%	**103**	Currently assumes 80%.
Emission Reduction T/yr					**411**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	377,730	6	0.65	3281.7	OAQPS Cost Cont Manual 6th ed - Eq 1.14

ATTACHMENT L

Model BART Cost Analysis - Pellet Coolers PM Emissions

List of Tables:

Table L-1: BART Screening Evaluation Summary: Pellet Cooler - Wet Scrubber, ESP, Wet Wall ESP, Fabric Filters and Multiclones

Model Source for Pellet Cooler Exhaust PM Emissions

General Information

Source Type	Pellet Cooler Exhaust
Pollutant:	Particulate Matter (PM10)
Existing Pollution Control Equipment	Most sources are routed to a wet scrubber

Control Cost Summary

Control Technology	Control Eff %	Emissions T/y	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton	Air Toxic's & AQRV's?	Energy Impacts?	Non-Air Env Impacts?
Wet Scrubbers High Efficiency	**99%**	**1028.6**	**1018.3**	**662,420**	**1,344,887**	**1,321**	**None**	**Medium**	**Wastewater**
Wet Scrubbers Low Efficiency	**92%**	**1028.6**	**946.3**	**662,420**	**1,344,887**	**1,421**	**None**	**Medium**	**Wastewater**
Dry ElectroStatic Precipitators (ESP)	**99%**	**1028.6**	**1018.3**	**4,004,917**	**792,842**	**779**	**None**	**Low**	**Solid Waste**
Wet Wall ElectroStatic Precipitator (WWESP)	**99%**	**1028.6**	**1018.3**	**4,125,064**	**2,572,757**	**2,527**	**None**	**Low**	**Wastewater**
Fabric Filters (Baghouses)	**99%**	**1028.6**	**1018.3**	**2,474,888**	**1,635,560**	**1,606**	**None**	**High**	**Solid Waste**
Multiclones	**80%**	**1028.6**	**822.9**	**455,957**	**898,336**	**1,092**	**None**	**High**	**Solid Waste**

Comments

Table L-2: Low Efficiency Wet Scrubber - Pellet Cooler - PM
BART Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC		**247,819**
Instrumentation	10% of control device cost (A)	24,782
MN Sales Taxes	6.5% of control device cost (A)	16,108
Freight	5% of control device cost (A)	12,391
Purchased Equipment Total (B)	22%	**301,100**
Installation		
Foundations & supports	12% of purchased equip cost (B)	36,132
Handling & erection	40% of purchased equip cost (B)	120,440
Electrical	1% of purchased equip cost (B)	3,011
Piping	30% of purchased equip cost (B)	90,330
Insulation	1% of purchased equip cost (B)	3,011
Painting	1% of purchased equip cost (B)	3,011
Installation Total	85%	**255,935**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Total Direct Capital Cost, DC		**557,035**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	30,110
Construction & field expenses	10% of purchased equip cost (B)	30,110
Construction fee	10% of purchased equip cost (B)	30,110
Start-up	1% of purchased equip cost (B)	3,011
Performance test	1% of purchased equip cost (B)	3,011
Contingencies	3% of purchased equip cost (B)	9,033
Total Indirect Capital Costs, IC	35%	**105,385**
Total Capital Investment (TCI) = DC + IC		**662,420**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	25.00 $/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	11,250
Supervisor	15% of oper labor costs 15%	1,688
Operating Materials		
Reagent #1	NA $/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	NA $/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA	-
Wastewater Treatment	1.50 $/Mgal, 431.0 gpm, 8000 hr/yr, 90.0% of capacity	279,266
Maintenance		
Maintenance Labor	17.50 1/2 hr per shift	8,750
Maintenance Materials	100% of maintenance labor costs	8,750
Electricity - Fan, Pump	0.05 $/kW-hr, 885 kW-hr, 8000 hr/yr, 90.0% of capacity	293,204
Total Annual Direct Operating Costs		**602,907**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	18,263
Administration (2% total capital costs)	2% of total capital costs (TCI)	13,248
Property tax (1% total capital costs)	1% of total capital costs (TCI)	6,624
Insurance (1% total capital costs)	1% of total capital costs (TCI)	6,624
Capital Recovery	14.24% for a 10- year equipment life and a 7% interest rate	94,314
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**741,980**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**1,344,887**
Pollutant Removed (tons/yr)[B]		**946**
Cost per ton of PM Removed		**1,421**

Notes & Assumptions

1 EPA Air Pollution Control Cost Manual 6th Ed 2002
2
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Table L-2: Low Efficiency Wet Scrubber - Pellet Cooler - PM (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	100,000	dscfm	102041 scfm
	800	Temp Deg F	
	2%	% Moisture	
	239,425	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,000**; **Utilization Rate:** **90.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Op Labor	25	Hr	0.5	hr/8 hr shift	450	11,250	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,688	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	450	4,125	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	885	kW-hr	6,373,994	293,204	$/kW-hr, 885 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	431.0	gpm	186,177	40,959	$/Mgal, 431.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0.0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0.0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.300 gr/dscf, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.300 gr/dscf, 8000 hr/yr
WW Treat	1.5	Mgal	431.0	gpm	186,177	279,266	$/Mgal, 431.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacit
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factc

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.3	gr/dscf	100,000	dscfm	NA	**1,028.6**	Assuming 92% control (range is 90-95%).
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				92%	**82**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**946.3**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	215,483	12	0.55	0.7	785.8	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Circ Pump	2,155	125	0.8	0.7	90.4	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	431.0	62.5	0.8	0.7	9.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	20.57 lb/hr SO2	2.50 lb NaOH/lb SO2	51.43 lb/hr Caustic
Lime Use	20.57 lb/hr SO2	1.53 lb Lime/lb SO2	31.47 lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8000 hr/yr, 90.0% of capacity

Table L-3: High Efficiency Wet Scrubber - Pellet Cooler - PM
BART Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC		**247,819**
Instrumentation	10% of control device cost (A)	24,782
MN Sales Taxes	6.5% of control device cost (A)	16,108
Freight	5% of control device cost (A)	12,391
Purchased Equipment Total (B)	22%	**301,100**
Installation		
Foundations & supports	12% of purchased equip cost (B)	36,132
Handling & erection	40% of purchased equip cost (B)	120,440
Electrical	1% of purchased equip cost (B)	3,011
Piping	30% of purchased equip cost (B)	90,330
Insulation	1% of purchased equip cost (B)	3,011
Painting	1% of purchased equip cost (B)	3,011
Installation Total	85%	**255,935**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Total Direct Capital Cost, DC		**557,035**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	30,110
Construction & field expenses	10% of purchased equip cost (B)	30,110
Construction fee	10% of purchased equip cost (B)	30,110
Start-up	1% of purchased equip cost (B)	3,011
Performance test	1% of purchased equip cost (B)	3,011
Contingencies	3% of purchased equip cost (B)	9,033
Total Indirect Capital Costs, IC	35%	**105,385**
Total Capital Investment (TCI) = DC + IC		**662,420**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	25.00 $/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	11,250
Supervisor	15% of oper labor costs 15%	1,688
Operating Materials		
Reagent #1	NA $/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	NA $/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA	-
Wastewater Treatment	1.50 $/Mgal, 431.0 gpm, 8000 hr/yr, 90.0% of capacity	279,266
Maintenance		
Maintenance Labor	17.50 1/2 hr per shift	8,750
Maintenance Materials	100% of maintenance labor costs	8,750
Electricity - Fan, Pump	0.05 $/kW-hr, 885 kW-hr, 8000 hr/yr, 90.0% of capacity	293,204
Total Annual Direct Operating Costs		**602,907**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	18,263
Administration (2% total capital costs)	2% of total capital costs (TCI)	13,248
Property tax (1% total capital costs)	1% of total capital costs (TCI)	6,624
Insurance (1% total capital costs)	1% of total capital costs (TCI)	6,624
Capital Recovery	14.24% for a 10- year equipment life and a 7% interest rate	94,314
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**741,980**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**1,344,887**
Pollutant Removed (tons/yr)[B]		**1,018**
Cost per ton of PM Removed		**1,321**

Notes & Assumptions

1 EPA Air Pollution Control Cost Manual 6th Ed 2002
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Table L-3: High Efficiency Wet Scrubber - Pellet Cooler - PM (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	100,000	dscfm	102041	scfm
	800	Temp Deg F		
	2%	% Moisture		
	239,425	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,000**; **Utilization Rate:** **90.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Op Labor	25	Hr	0.5	hr/8 hr shift	450	11,250	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,688	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	450	4,125	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	885	kW-hr	6,373,994	293,204	$/kW-hr, 885 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	431.0	gpm	186,177	40,959	$/Mgal, 431.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0.0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0.0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.300 gr/dscf, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.300 gr/dscf, 8000 hr/yr
WW Treat	1.5	Mgal	431.0	gpm	186,177	279,266	$/Mgal, 431.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.3	gr/dscf	100,000	dscfm	NA	**1,028.6**	Assuming 99% control.
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99%	**10**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1018.3**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	215,483	12	0.55	0.7	785.8	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Circ Pump	2,155	125	0.8	0.7	90.4	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	431.0	62.5	0.8	0.7	9.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	2.57 lb/hr SO2	2.50 lb NaOH/lb SO2	6.43 lb/hr Caustic
Lime Use	2.57 lb/hr SO2	1.53 lb Lime/lb SO2	3.93 lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8000 hr/yr, 90.0% of capacity

Table L-4: ESP - Pellet Cooler - PM
BART Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
ESP + auxillary equipment		**1,521,972**
Instrumentation	10% of control device cost (A)	152,197
MN Sales Taxes	3% of control device cost (A)	45,659
Freight	5% of control device cost (A)	76,099
Purchased Equipment Total (B)	18%	**1,795,927**
Direct Installation Costs		
Foundations & supports	4% of purchased equip cost (B)	71,837
Handling & erection	50% of purchased equip cost (B)	897,963
Electrical	8% of purchased equip cost (B)	143,674
Piping	1% of purchased equip cost (B)	17,959
Insulation for ductwork	2% of purchased equip cost (B)	35,919
Painting	2% of purchased equip cost (B)	35,919
Direct Installation Costs		**1,203,271**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Total Direct Capital Costs, DC	67%	**2,999,198**
Indirect Capital Costs		
Engineering	20% of purchased equip cost (B)	359,185
Construction & field expenses	20% of purchased equip cost (B)	359,185
Constractor fees	10% of purchased equip cost (B)	179,593
Start-up	1% of purchased equip cost (B)	17,959
Performance Test	1% of purchased equip cost (B)	
Model Study	2% of purchased equip cost (B)	35,919
Contingencies	3% of purchased equip cost (B)	53,878
Total Indirect Capital Costs	57%	**1,005,719**
Total Capital Investment (TCI) = DC + IC		**4,004,917**
OPERATING COSTS		
Direct Operating Costs		
Operator	25.00 $/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	25,000
Supervisor	15% of operator costs	3,750
Coordinator	33% of operator costs	8,250
Operating materials		
Maintenance Labor	0.1155 $/ft2 collector area; $5775 if < 50,000 ft2	8,405
Maintenance Materials	1% of purchased equipment costs	17,959
Utilities		
Electricity	0.05 $/kW-hr, 361 kW-hr, 8000 hr/yr, 90.0% of capacity	132,720
Water	NA	-
Solid Waste Disposal	25.00 $/Ton, 0.300 gr/dscf, 8000 hr/yr	25,457
Wastewater Treatment	NA	-
Total Annual Direct Operating Costs, DC		**221,541**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	33,068
Administration (2% total capital costs)	2% of total capital costs (TCI)	80,098
Property tax (1% total capital costs)	1% of total capital costs (TCI)	40,049
Insurance (1% total capital costs)	1% of total capital costs (TCI)	40,049
Captial Recovery	9% for a 20- year equipment life and a 7% interest rate	378,036
Total Indirect Operating Costs		**571,301**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**792,842**
Pollutant Removed (tons/yr)[B]		**1,018.3**
Cost per ton of PM Removed		**779**

Notes & Assumptions

1 1 EPA Air Pollution Control Cost Manual 6th Ed 2002
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Table L-4: ESP - Pellet Cooler - PM (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	100,000	dscfm	102041	scfm
	800	Temp Deg F		
	2%	% Moisture		
	239,425	acfm		

Operating Cost Calculations				**Annual hours of operation:**		**8,000**	
				Utilization Rate:		**90.0%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	1	hr/8 hr shift	1,000	25,000	$/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.1155	$/ft^2 collector	72,768	ft^2 collector area		8,405	$/ft^2 collector area; $5775 if < 50,000 f^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	361	kW-hr	2,885,217	132,720	$/kW-hr, 361 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0.0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25	Ton	0.127	ton/hr	1,018	25,457	$/Ton, 0.300 gr/dscf, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.300 gr/dscf, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.3	gr/dscf	100,000	dscfm	NA	**1028.57**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99%	**10**	Currently assumes 99%.
Emission Reduction T/yr					**1018.3**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower Eff		kW	
Blower	239,425	5	0.65		215.5	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	72,768	141.2	2	4	145.2	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Estimate Area (ft2)		
Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	239,425	acfm
Area #2	**72768**	**ft2**

Table L-5: Wet Wall ESP - Pellet Cooler - PM
BART Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
ESP + auxillary equipment		**1,567,631**
Instrumentation	10% of control device cost (A)	156,763
MN Sales Taxes	3% of control device cost (A)	47,029
Freight	5% of control device cost (A)	78,382
Purchased Equipment Total (B)	18%	**1,849,805**
Direct Installation Costs		
Foundations & supports	4% of purchased equip cost (B)	73,992
Handling & erection	50% of purchased equip cost (B)	924,902
Electrical	8% of purchased equip cost (B)	147,984
Piping	1% of purchased equip cost (B)	18,498
Insulation for ductwork	2% of purchased equip cost (B)	36,996
Painting	2% of purchased equip cost (B)	36,996
Direct Installation Costs		**1,239,369**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Total Direct Capital Costs, DC	67%	**3,089,174**
Indirect Capital Costs		
Engineering	20% of purchased equip cost (B)	369,961
Construction & field expenses	20% of purchased equip cost (B)	369,961
Constractor fees	10% of purchased equip cost (B)	184,980
Start-up	1% of purchased equip cost (B)	18,498
Performance Test	1% of purchased equip cost (B)	
Model Study	2% of purchased equip cost (B)	36,996
Contingencies	3% of purchased equip cost (B)	55,494
Total Indirect Capital Costs	57%	**1,035,891**
Total Capital Investment (TCI) = DC + IC		**4,125,064**
OPERATING COSTS		
Direct Operating Costs		
Operator	12.00 $/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	12,000
Supervisor	15% of operator costs	1,800
Coordinator	33% of operator costs	3,960
Operating materials		
Maintenance Labor	0.1155 $/ft2 collector area; $5775 if < 50,000 ft2	8,405
Maintenance Materials	1% of purchased equipment costs	18,498
Utilities		
Electricity	0.05 $/kW-hr, 462 kW-hr, 8000 hr/yr, 90.0% of capacity	169,973
Water	0.22 $/Mgal, 2,154.8 gpm, 8000 hr/yr, 90.0% of capacity	227,550
Solid Waste Disposal	NA	-
Wastewater Treatment	1.50 $/Mgal, 2,154.8 gpm, 8000 hr/yr, 90.0% of capacity	1,551,476
Reagent (Caustic)	280.00 $/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	294
Total Annual Direct Operating Costs, DC		**1,993,956**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	24,422
Administration (2% total capital costs)	2% of total capital costs (TCI)	82,501
Property tax (1% total capital costs)	1% of total capital costs (TCI)	41,251
Insurance (1% total capital costs)	1% of total capital costs (TCI)	41,251
Captial Recovery	9% for a 20- year equipment life and a 7% interest rate	389,377
Total Indirect Operating Costs		**578,801**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**2,572,757**
Pollutant Removed (tons/yr)[B]		**1,018.3**
Cost per ton of PM Removed		**2,527**

Notes & Assumptions

1 1 Equipment cost estimates assumed to be 3% higher than that of dry ESP.
2 EPA Cost Manual 6th Ed. 2002
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Table L-5: Wet Wall ESP - Pellet Cooler - PM (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	100,000	dscfm	102041	scfm
	800	Temp Deg F		
	2%	% Moisture		
	239,425	acfm		

Operating Cost Calculations — **Annual hours of operation: 8,000** — **Utilization Rate: 90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	12	Hr	1	hr/8 hr shift	1,000	12,000	$/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.1155	$/ft^2 collector	72,768	ft^2 collector area		8,405	$/ft^2 collector area; $5775 if < 50,000 f^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	462	kW-hr	3,695,073	169,973	$/kW-hr, 462 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	2155	gpm	1,034,318	227,550	$/Mgal, 2,154.8 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0.003	lb-mole/hr	1	294	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.300 gr/dscf, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.300 gr/dscf, 8000 hr/yr
WW Treat	1.5	Mgal	2155	gpm	1,034,318	1,551,476	$/Mgal, 2,154.8 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacit
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.3	gr/dscf	100,000	dscfm	NA	**1028.57**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99%	**10**	Currently assumes 99%.
Emission Reduction T/yr					**1018.3**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	D P in H2O	Blower Eff	Motor Eff		
Blower	239,425	5	0.55	0.9	283.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	2155	60	0.8	0.9	33.8	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	0	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	72,768	141.2	2	4	145.2	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Caustic Use	2.57	lb/hr SO2	2.50	lb NaOH/lb SO2	0.003	T/hr Caustic
Lime Use	2.57	lb/hr SO2	1.53	lb Lime/lb SO2	0.002	T/hr Lime

Estimate Area (ft2)

Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	239,425	acfm
Area #2	**72768**	**ft2**

Table L-6: Baghouse - Pellet Cooler - PM
BART Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Fabric Filter (EC) + bags + auxillary equipment		**957,700**
Instrumentation	10% of control device cost (A)	95,770
MN Sales Taxes	3% of control device cost (A)	28,731
Freight	5% of control device cost (A)	47,885
Purchased Equipment Total (B)	18%	**1,130,086**
Direct installation costs		
Foundations & supports	4% of purchased equip cost (B)	45,203
Handling & erection	50% of purchased equip cost (B)	565,043
Electrical	8% of purchased equip cost (B)	90,407
Piping	1% of purchased equip cost (B)	11,301
Insulation for ductwork	7% of purchased equip cost (B)	79,106
Painting	4% of purchased equip cost (B)	45,203
Installation Total	74%	**836,264**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Total Direct Capital Cost		**1,966,350**
Indirect Capital Costs		
Engineering	10% of purchased equip cost (B)	113,009
Construction and field expense	20% of purchased equip cost (B)	226,017
Contractor fees	10% of purchased equip cost (B)	113,009
Startup	1% of purchased equip cost (B)	11,301
Performance test	1% of purchased equip cost (B)	11,301
Contingencies	3% of purchased equip cost (B)	33,903
Total Indirect Capital Costs	45%	**508,539**
Total Capital Investment (TCI) = DC + IC		**2,474,888**
OPERATING COSTS		
Direct Operating Costs		
Operating Labor	25.00 $/Hr, 2.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	50,000
Supervisor	15% of operator labor costs	7,500
Maintenance Labor	17.50 $/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	17,500
Maintenance Materials	100% of maintenance labor costs	17,500
Replacement parts, bags		155,978
Utilities		
Electricity	0.05 $/kW-hr, 2,080 kW-hr, 8000 hr/yr, 90.0% of capacity	765,487
Compressed Air	0.27 $/mscf, 100 scfm, 8640 hr/yr	62,059
Solid Waste Disposal	25.00 $/Ton, 0.300 gr/dscf, 8000 hr/yr	171,429
Total Annual Direct Operating Costs (DC)		**1,247,452**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	55,500
Administration (2% total capital costs)	2% of total capital costs (TCI)	49,498
Property tax (1% total capital costs)	1% of total capital costs (TCI)	24,749
Insurance (1% total capital costs)	1% of total capital costs (TCI)	24,749
Capital Recovery	9% for a 20- year equipment life and a 7% interest rate	233,612
Total Indirect Operating Costs		**388,107**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**1,635,560**
Pollutant Removed (tons/yr)[B]		**1,018**
Cost per ton of PM Removed		**1,606**

Notes & Assumptions

1 1 EPA Air Pollution Control Cost Manual 6th Ed 2002
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Table L-6: Baghouse - Pellet Cooler - PM (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35	$ each
Amount Required	3,831	Number
Total Rep Parts Cost	144,804	Cost adjusted for freight & sales tax
Installation Labor	11,173	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**155,978**	
Annualized Cost	**86,270**	

Total Cost Replacement Parts (Bags) **155,978**

Design Flow	100,000	dscfm	102041	scfm
	800	Temp Deg F		
	2%	% Moisture		
	239,425	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,000**; **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	2	hr/8 hr shift	2,000	50,000	$/Hr, 2.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.5	Hr	1	hr/8 hr shift	1,000	17,500	$/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	2080	kW-hr	16,641,022	765,487	$/kW-hr, 2,080 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/mscf, 40 scfm, 8000 hr/yr
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 7.16 gpm; 8000 hr/yr
Comp Air	0.27	Mscf	478.85	Mscfm	229,848	62,059	$/mscf, 100 scfm, 8640 hr/yr
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/T, 62 lb/lbmole, 0.76wt% NaOH, 8000 hr/yr
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/T, 62 lb/lbmole, 0.76wt% NaOH, 8000 hr/yr
SW Disposal	25	Ton	0.857	ton/hr	6,857	171,429	$/Ton, 0.300 gr/dscf, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.300 gr/dscf, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 7.16 gpm; 8000 hr/yr
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 39 ft3 of catalyst, 2 yr cat life
Rep Parts	35	bag	3830.806065	bags	2 yr life	86,270	795 bags, 2 yr life

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.3	gr/dscf	100,000	dscfm	NA	**1029**	

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99%	**10**	Currently assumes 99%.
Emission Reduction T/yr					**1,018**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	239,425	6	0.65	2080	OAQPS Cost Cont Manual 6th ed - Eq 1.14

Table L-7: Multiclone - Pellet Cooler - PM
BART Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Equipment		**194,173**
Instrumentation	10% of control device cost (A)	19,417
MN Sales Taxes	3% of control device cost (A)	5,825
Freight	5% of control device cost (A)	9,709
Purchased Equipment Total (B)	18%	**229,124**
Direct installation costs		
Foundations & supports	4% of purchased equip cost (B)	9,165
Handling & erection	40% of purchased equip cost (B)	91,650
Electrical	8% of purchased equip cost (B)	18,330
Piping	1% of purchased equip cost (B)	2,291
Insulation for ductwork	7% of purchased equip cost (B)	16,039
Painting	4% of purchased equip cost (B)	9,165
Installation Total	74%	**146,639**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Total Direct Capital Cost		**375,764**
Indirect Capital Costs		
Engineering	10% of purchased equip cost (B)	22,912
Construction and field expense	10% of purchased equip cost (B)	22,912
Contractor fees	10% of purchased equip cost (B)	22,912
Startup	1% of purchased equip cost (B)	2,291
Performance test	1% of purchased equip cost (B)	2,291
Contingencies	3% of purchased equip cost (B)	6,874
Total Indirect Capital Costs	45%	**80,193**
Total Capital Investment (TCI) = DC + IC		**455,957**
OPERATING COSTS		
Direct Operating Costs		
Operating Labor	25.00 \$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	12,500
Supervisor	15% of operator labor costs	1,875
Maintenance Labor	17.50 \$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	8,750
Maintenance Materials	100% of maintenance labor costs	8,750
Replacement parts, bags		0
Utilities		
Electricity	0.05 \$/kW-hr, 2,080 kW-hr, 8000 hr/yr, 90.0% of capacity	765,487
Compressed Air	NA	-
Solid Waste Disposal	25.00 \$/Ton, 0.300 gr/dscf, 8000 hr/yr	20,571
Total Annual Direct Operating Costs (DC)		**817,933**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	19,125
Administration (2% total capital costs)	2% of total capital costs (TCI)	9,119
Property tax (1% total capital costs)	1% of total capital costs (TCI)	4,560
Insurance (1% total capital costs)	1% of total capital costs (TCI)	4,560
Capital Recovery	9% for a 20- year equipment life and a 7% interest rate	43,039
Total Indirect Operating Costs		**80,402**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**898,336**
Pollutant Removed (tons/yr)[B]		**823**
Cost per ton of PM Removed		**1,092**

Notes & Assumptions

1 EPA Air Pollution Control Cost Manual 6th Ed 2002. Assumed same cost factors as baghouse.
2 Equipment cost estimated using 0.6 Power factor in conjunction with multiclone quote provided by Allen-Sherman-Hoff.
3 Reduced erection to 40% and Const Field Exp to 10% to address simpler installation.
4 Reduced operator and maintenance hours to address simpler operation.
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Table L-7: Multiclone - Pellet Cooler - PM (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	0	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts (Bags) **0**

Design Flow	100,000 dscfm	102041	scfm
	800 Temp Deg F		
	2% % Moisture		
	239,425 acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,000**; **Utilization Rate:** **90.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Op Labor	25	Hr	0.5	hr/8 hr shift	500	12,500	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	500	8,750	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	2080	kW-hr	16,641,022	765,487	$/kW-hr, 2,080 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	-	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25	Ton	0.103	ton/hr	823	20,571	$/Ton, 0.300 gr/dscf, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.300 gr/dscf, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.3	gr/dscf	100,000	dscfm	NA	**1029**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				80%	**206**	Currently assumes 80%.
Emission Reduction T/yr					**823**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	239,425	6	0.65	2080	OAQPS Cost Cont Manual 6th ed - Eq 1.14

ATTACHMENT M

Model BART Cost Analysis - Iron Ore Material Handling PM Emissions

List of Tables:

Table M-1: BART Screening Evaluation Summary: Material Handling - Wet Scrubber, ESP, Wet Wall ESP, Fabric Filters, Multiclones and Enclosures

Model Source for Iron Ore Material Handling - PM Emissions from Conveyor Drops

General Information

Source Type	Iron Ore Material Handling - Conveyor Drops
Pollutant:	Particulate Matter (PM10)
Existing Pollution Control Equipment	Most sources are routed to a wet scrubber

Control Cost Summary

Control Technology	Control Eff %	Emissions T/y	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton	Air Toxic's & AQRV's?	Energy Impacts?	Non-Air Env Impacts?
Wet Scrubbers High Efficiency	**99%**	**11.7**	**11.6**	**127,932**	**136,627**	**11,795**	**None**	**High**	**Waste-Water**
Wet Scrubbers Low Efficiency	**92%**	**11.7**	**10.8**	**126,283**	**136,326**	**12,665**	**None**	**High**	**Waste-Water**
Dry ElectroStatic Precipitators (ESP)	**99%**	**11.7**	**11.6**	**1,644,512**	**301,977**	**26,071**	**None**	**Medium**	**Solid Waste**
Wet Wall ElectroStatic Precipitator (WWESP)	**99%**	**11.7**	**11.6**	**1,693,848**	**334,648**	**28,891**	**None**	**Medium**	**Waste-Water**
Fabric Filters (Baghouses)	**99%**	**11.7**	**11.6**	**83,625**	**189,010**	**16,318**	**None**	**Low**	**Solid Waste**
Multiclones*	**80%**	**11.7**	**9.4**	**21,459**	**31,055**	**3,318**	**None**	**Low**	**Solid Waste**
Enclosure	**NA**	**11.7**	**11.3**	**55,611**	**51,977**	**4,586**	**None**	**None**	**None**

* Control costs based on connecting 10 sources together; a single source was too small for the vendor to provide a cost estimate. Values for emissions, emissions reduction, installed capital cost and annualized operating cost are 1/10 of the values listed in Table M-7 to account for this issue.

Table M-2: Low Efficiency Wet Scrubber - Material Handling - PM
BART Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**47,244**
Instrumentation	10%	of control device cost (A)	4,724
MN Sales Taxes	6.5%	of control device cost (A)	3,071
Freight	5%	of control device cost (A)	2,362
Purchased Equipment Total (B)	22%		**57,401**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	6,888
Handling & erection	40%	of purchased equip cost (B)	22,961
Electrical	1%	of purchased equip cost (B)	574
Piping	30%	of purchased equip cost (B)	17,220
Insulation	1%	of purchased equip cost (B)	574
Painting	1%	of purchased equip cost (B)	574
Installation Total	85%		**48,791**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**106,193**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	5,740
Construction & field expenses	10%	of purchased equip cost (B)	5,740
Construction fee	10%	of purchased equip cost (B)	5,740
Start-up	1%	of purchased equip cost (B)	574
Performance test	1%	of purchased equip cost (B)	574
Contingencies	3%	of purchased equip cost (B)	1,722
Total Indirect Capital Costs, IC	35%		**20,091**
Total Capital Investment (TCI) = DC + IC			**126,283**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.00	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	11,250
Supervisor	15%	of oper labor costs 15%	1,688
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	NA	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA		-
Wastewater Treatment	1.50	$/Mgal, 12.9 gpm, 8000 hr/yr, 90.0% of capacity	8,331
Maintenance			
Maintenance Labor	17.50	1/2 hr per shift	8,750
Maintenance Materials	100%	of maintenance labor costs	8,750
Electricity - Fan, Pump	0.05	$/kW-hr, 26 kW-hr, 8000 hr/yr, 90.0% of capacity	8,747
Total Annual Direct Operating Costs			**47,516**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	18,263
Administration (2% total capital costs)	2%	of total capital costs (TCI)	2,526
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,263
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,263
Capital Recovery	14.24%	x total capital costs (TCI)	17,980
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**88,810**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**136,326**
Pollutant Removed (tons/yr)[B]			**11**
Cost per ton of PM Removed			**12,665**

Notes & Assumptions

1 EPA Air Pollution Control Cost Manual 6th Ed 2002
2 Equipment cost estimates based on cost curve with 2001 vendor data.
3
4
5
6

Table M-2: Low Efficiency Wet Scrubber - Material Handling - PM (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	7,000	dscfm	7143	scfm
	77	Temp Deg F		
	2%	% Moisture		
	7,143	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,000**; **Utilization Rate:** **90.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Op Labor	25	Hr	0.5	hr/8 hr shift	450	11,250	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,688	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	450	4,125	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	26.4	kW-hr	190,157	8,747	$/kW-hr, 26 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	12.9	gpm	5,554	1,222	$/Mgal, 12.9 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0.0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0.0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.0	ton/hr	0	0	$/Ton, 0.300 gr/dscf, 8000 hr/yr
Haz W Disp	273	Ton	0.0	ton/hr	0	0	$/Ton, 0.300 gr/dscf, 8000 hr/yr
WW Treat	1.5	Mgal	12.9	gpm	5,554	8,331	$/Mgal, 12.9 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.3	gr/dscf	7,000	dscfm	NA	**11.7**	Use uncontrolled emission rate from enclosure case.
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				92%	**0.9**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**10.8**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	6,429	12	0.55	0.7	23.4	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Circ Pump	64	125	0.8	0.7	2.7	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	12.9	62.5	0.8	0.7	0.3	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	2.925	lb/hr SO2	2.50	lb NaOH/lb SO2	7.3	lb/hr Caustic
Lime Use	2.925	lb/hr SO2	1.53	lb Lime/lb SO2	4.5	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8000 hr/yr, 90.0% of capacity

Table M-3: High Efficiency Wet Scrubber - Material Handling - PM
BART Emission Control Cost Analysis

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**47,861**
Instrumentation	10%	of control device cost (A)	4,786
MN Sales Taxes	6.5%	of control device cost (A)	3,111
Freight	5%	of control device cost (A)	2,393
Purchased Equipment Total (B)	22%		**58,151**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	6,978
Handling & erection	40%	of purchased equip cost (B)	23,260
Electrical	1%	of purchased equip cost (B)	582
Piping	30%	of purchased equip cost (B)	17,445
Insulation	1%	of purchased equip cost (B)	582
Painting	1%	of purchased equip cost (B)	582
Installation Total	85%		**49,428**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**107,580**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	5,815
Construction & field expenses	10%	of purchased equip cost (B)	5,815
Construction fee	10%	of purchased equip cost (B)	5,815
Start-up	1%	of purchased equip cost (B)	582
Performance test	1%	of purchased equip cost (B)	582
Contingencies	3%	of purchased equip cost (B)	1,745
Total Indirect Capital Costs, IC	35%		**20,353**
Total Capital Investment (TCI) = DC + IC			**127,932**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.00	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	11,250
Supervisor	15%	of oper labor costs 15%	1,688
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	NA	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA		-
Wastewater Treatment	1.50	$/Mgal, 12.9 gpm, 8000 hr/yr, 90.0% of capacity	8,331
Maintenance			
Maintenance Labor	17.50	1/2 hr per shift	8,750
Maintenance Materials	100%	of maintenance labor costs	8,750
Electricity - Fan, Pump	0.05	$/kW-hr, 26 kW-hr, 8000 hr/yr, 90.0% of capacity	8,747
Total Annual Direct Operating Costs			**47,516**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	18,263
Administration (2% total capital costs)	2%	of total capital costs (TCI)	2,559
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,279
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,279
Capital Recovery	14.24%	x total capital costs (TCI)	18,215
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**89,111**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**136,627**
Pollutant Removed (tons/yr)[B]			**12**
Cost per ton of PM Removed			**11,795**

Notes & Assumptions

1 EPA Air Pollution Control Cost Manual 6th Ed 2002
2 Equipment cost estimates based on cost curve with 2001 vendor data.
3
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Table M-3: High Efficiency Wet Scrubber - Material Handling - PM (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	7,000	dscfm	7143	scfm
	77	Temp Deg F		
	2%	% Moisture		
	7,143	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,000**; **Utilization Rate:** **90.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Op Labor	25	Hr	0.5	hr/8 hr shift	450	11,250	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,688	15% of Operator Costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	450	4,125	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	26.4	kW-hr	190,157	8,747	$/kW-hr, 26 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	12.9	gpm	5,554	1,222	$/Mgal, 12.9 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0.0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0.0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8000 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.0	ton/hr	0	0	$/Ton, 0.300 gr/dscf, 8000 hr/yr
Haz W Disp	273	Ton	0.0	ton/hr	0	0	$/Ton, 0.300 gr/dscf, 8000 hr/yr
WW Treat	1.5	Mgal	12.9	gpm	5,554	8,331	$/Mgal, 12.9 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.3	gr/dscf	7,000	dscfm	NA	**11.7**	Use uncontrolled emission rate from enclosure case.
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99%	**0.1**	Basis:8000 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**11.6**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	6,429	12	0.55	0.7	23.4	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Circ Pump	64	125	0.8	0.7	2.7	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	12.9	62.5	0.8	0.7	0.3	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	2.925 lb/hr SO2	2.50 lb NaOH/lb SO2	7.3	lb/hr Caustic
Lime Use	2.925 lb/hr SO2	1.53 lb Lime/lb SO2	4.5	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8000 hr/yr, 90.0% of capacity

Table M-4: ESP - Material Handling - PM
BACT Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
ESP + auxillary equipment		**606,954**
Instrumentation	10% of control device cost (A)	60,695
MN Sales Taxes	7% of control device cost (A)	39,452
Freight	5% of control device cost (A)	30,348
Purchased Equipment Total (B)	22%	**737,449**
Direct Installation Costs		
Foundations & supports	4% of purchased equip cost (B)	29,498
Handling & erection	50% of purchased equip cost (B)	368,725
Electrical	8% of purchased equip cost (B)	58,996
Piping	1% of purchased equip cost (B)	7,374
Insulation for ductwork	2% of purchased equip cost (B)	14,749
Painting	2% of purchased equip cost (B)	14,749
Direct Installation Costs		**494,091**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Total Direct Capital Costs, DC	67%	**1,231,540**
Indirect Capital Costs		
Engineering	20% of purchased equip cost (B)	147,490
Construction & field expenses	20% of purchased equip cost (B)	147,490
Constractor fees	10% of purchased equip cost (B)	73,745
Start-up	1% of purchased equip cost (B)	7,374
Performance Test	1% of purchased equip cost (B)	
Model Study	2% of purchased equip cost (B)	14,749
Contingencies	3% of purchased equip cost (B)	22,123
Total Indirect Capital Costs	57%	**412,972**
Total Capital Investment (TCI) = DC + IC		**1,644,512**
OPERATING COSTS		
Direct Operating Costs		
Operator	25.00 $/hr, 1 hr/shift, 8 hr/shift, 8640 hr/yr	25,000
Supervisor	15% of operator costs	3,750
Coordinator	33% of operator costs	8,250
Operating materials		
Maintenance Labor	0.1155 $/ft2 collector area; $5775 if < 50,000 ft2	5,775
Maintenance Materials	1% of purchased equipment costs	7,374
Utilities		
Electricity	0.05 $/kW-hr, 15 kW-hr, 8000 hr/yr, 90.0% of capacity	5,388
Water	NA	-
Solid Waste Disposal	25.00 $/Ton, 0.300 gr/dscf, 8000 hr/yr	290
Wastewater Treatment	NA	-
Total Annual Direct Operating Costs, DC		**55,827**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	25,140
Administration (2% total capital costs)	2% of total capital costs (TCI)	32,890
Property tax (1% total capital costs)	1% of total capital costs (TCI)	16,445
Insurance (1% total capital costs)	1% of total capital costs (TCI)	16,445
Captial Recovery	9%	155,230
Total Indirect Operating Costs		**246,150**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**301,977**
Pollutant Removed (tons/yr)[B]		**11.6**
Cost per ton of PM Removed		**26,071**

Notes & Assumptions

1 1 EPA Air Pollution Control Cost Manual 6th Ed 2002
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Table M-4: ESP - Material Handling - PM (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	7,000	dscfm	7143 scfm
	77	Temp Deg F	
	2%	% Moisture	
	7,143	acfm	

Operating Cost Calculations — **Annual hours of operation: 8,000** — **Utilization Rate: 90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	1	hr/8 hr shift	1,000	25,000	$/hr, 1 hr/shift, 8 hr/shift, 8640 hr/yr
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.1155	$/ft^2 collecto	2,171	ft^2 collector area		5,775	$/ft^2 collector area; $5775 if < 50,000 f^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	14.6	kW-hr	117,121	5,388	$/kW-hr, 15 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25	Ton	0.001	ton/hr	12	290	$/Ton, 0.300 gr/dscf, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.300 gr/dscf, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacit
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.3	gr/dscf	7,000	dscfm	NA	**11.7**	Use uncontrolled emission rate from enclosure case.

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99%	**0**	Currently assumes 99%.
Emission Reduction T/yr					**11.6**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	D P in H2O	Blower Eff			
Blower	7,143	5	0.65		6.4	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	2,171	4.2	2	4	8.2	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Estimate Area (ft2)

Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	7,143	acfm
Area #2	**2171**	**ft2**

Table M-5: Wet Wall ESP - Material Handling - PM
BACT Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
ESP + auxillary equipment		**625,163**
Instrumentation	10% of control device cost (A)	62,516
MN Sales Taxes	6.5% of control device cost (A)	40,636
Freight	5% of control device cost (A)	31,258
Purchased Equipment Total (B)	22%	**759,573**
Direct Installation Costs		
Foundations & supports	4% of purchased equip cost (B)	30,383
Handling & erection	50% of purchased equip cost (B)	379,787
Electrical	8% of purchased equip cost (B)	60,766
Piping	1% of purchased equip cost (B)	7,596
Insulation for ductwork	2% of purchased equip cost (B)	15,191
Painting	2% of purchased equip cost (B)	15,191
Direct Installation Costs		**508,914**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Total Direct Capital Costs, DC	67%	**1,268,487**
Indirect Capital Costs		
Engineering	20% of purchased equip cost (B)	151,915
Construction & field expenses	20% of purchased equip cost (B)	151,915
Constractor fees	10% of purchased equip cost (B)	75,957
Start-up	1% of purchased equip cost (B)	7,596
Performance Test	1% of purchased equip cost (B)	
Model Study	2% of purchased equip cost (B)	15,191
Contingencies	3% of purchased equip cost (B)	22,787
Total Indirect Capital Costs	57%	**425,361**
Total Capital Investment (TCI) = DC + IC		**1,693,848**
OPERATING COSTS		
Direct Operating Costs		
Operator	12.00 $/hr, 1 hr/shift, 8 hr/shift, 8640 hr/yr	12,000
Supervisor	15% of operator costs	1,800
Coordinator	33% of operator costs	3,960
Operating materials		
Maintenance Labor	0.1155 $/ft2 collector area; $5775 if < 50,000 ft2	5,775
Maintenance Materials	1% of purchased equipment costs	7,596
Utilities		
Electricity	0.05 $/kW-hr, 18 kW-hr, 8000 hr/yr, 90.0% of capacity	6,499
Water	0.22 $/Mgal, 64.3 gpm, 8000 hr/yr, 90.0% of capacity	6,789
Solid Waste Disposal	NA	-
Wastewater Treatment	1.50 $/Mgal, 64.3 gpm, 8000 hr/yr, 90.0% of capacity	46,286
Reagent (Caustic)	280.00 $/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Total Annual Direct Operating Costs, DC		**90,704**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	16,302
Administration (2% total capital costs)	2% of total capital costs (TCI)	33,877
Property tax (1% total capital costs)	1% of total capital costs (TCI)	16,938
Insurance (1% total capital costs)	1% of total capital costs (TCI)	16,938
Captial Recovery	9%	159,887
Total Indirect Operating Costs		**243,944**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**334,648**
Pollutant Removed (tons/yr)[B]		**11.6**
Cost per ton of PM Removed		**28,891**

Notes & Assumptions

1 1 Equipment cost estimates assumed to be 3% higher than that of dry ESP.
2 EPA Cost Manual 6th Ed. 2002
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Table M-5: Wet Wall ESP - Material Handling - PM (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	7,000	dscfm	7143	scfm
	77	Temp Deg F		
	2%	% Moisture		
	7,143	acfm		

Operating Cost Calculations				**Annual hours of operation:**		**8,000**	
				Utilization Rate:		**90.0%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	12	Hr	1	hr/8 hr shift	1,000	12,000	$/hr, 1 hr/shift, 8 hr/shift, 8640 hr/yr
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.1155	$/ft^2 collecto	2,171	ft^2 collector area		5,775	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	17.7	kW-hr	141,282	6,499	$/kW-hr, 18 kW-hr, 8000 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8000 hr/yr, 90.0% of capacity
Water	0.22	Mgal	64	gpm	30,857	6,789	$/Mgal, 64.3 gpm, 8000 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8000 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8000 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.300 gr/dscf, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.300 gr/dscf, 8000 hr/yr
WW Treat	1.5	Mgal	64	gpm	30,857	46,286	$/Mgal, 64.3 gpm, 8000 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8000 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8000 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.3	gr/dscf	7,000	dscfm	NA	**11.7**	Use uncontrolled emission rate from enclosure case.
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99%	**0**	Currently assumes 99%.
Emission Reduction T/yr					**11.6**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	7,143	5	0.55	0.9	8.4	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	64	60	0.8	0.9	1.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	0	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	2,171	4.2	2	4	8.2	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Caustic Use	2.925	lb/hr SO2	2.50	lb NaOH/lb SO2	0.004	T/hr Caustic
Lime Use	2.925	lb/hr SO2	1.53	lb Lime/lb SO2	0.002	T/hr Lime

Estimate Area (ft2)		
Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	7,143	acfm
Area #2	**2171**	**ft2**

Table M-6: Baghouse - Material Handling - PM
BACT Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Fabric Filter (EC) + bags + auxillary equipment		**31,428**
Instrumentation	10% of control device cost (A)	3,143
MN Sales Taxes	6.5% of control device cost (A)	2,043
Freight	5% of control device cost (A)	1,571
Purchased Equipment Total (B)	18%	**38,185**
Direct installation costs		
Foundations & supports	4% of purchased equip cost (B)	1,527
Handling & erection	50% of purchased equip cost (B)	19,093
Electrical	8% of purchased equip cost (B)	3,055
Piping	1% of purchased equip cost (B)	382
Insulation for ductwork	7% of purchased equip cost (B)	2,673
Painting	4% of purchased equip cost (B)	1,527
Installation Total	74%	**28,257**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Total Direct Capital Cost		**66,442**
Indirect Capital Costs		
Engineering	10% of purchased equip cost (B)	3,819
Construction and field expense	20% of purchased equip cost (B)	7,637
Contractor fees	10% of purchased equip cost (B)	3,819
Startup	1% of purchased equip cost (B)	382
Performance test	1% of purchased equip cost (B)	382
Contingencies	3% of purchased equip cost (B)	1,146
Total Indirect Capital Costs	45%	**17,183**
Total Capital Investment (TCI) = DC + IC		**83,625**
OPERATING COSTS		
Direct Operating Costs		
Operating Labor	25.00 $/Hr, 2.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	50,000
Supervisor	15% of operator labor costs	7,500
Maintenance Labor	17.50 $/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	17,500
Maintenance Materials	100% of maintenance labor costs	17,500
Replacement parts, bags		4,793
Utilities		
Electricity	0.05 $/kW-hr, 36.4 kW; 8640 hr/yr	22,837
Compressed Air	0.27 $/mscf, 100 scfm, 8640 hr/yr	1,851
Solid Waste Disposal	25.00 $/Ton, 0.300 gr/dscf, 8000 hr/yr	290
Total Annual Direct Operating Costs (DC)		**122,271**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	55,500
Administration (2% total capital costs)	2% of total capital costs (TCI)	1,673
Property tax (1% total capital costs)	1% of total capital costs (TCI)	836
Insurance (1% total capital costs)	1% of total capital costs (TCI)	836
Capital Recovery	9% for a 20- year equipment life and a % interest rate	7,894
Total Indirect Operating Costs		**66,739**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**189,010**
Pollutant Removed (tons/yr)[B]		**12**
Cost per ton of PM Removed		**16,318**

Notes & Assumptions

1 EPA Cost Manual 6th Ed. 2002
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Table M-6: Baghouse - Material Handling - PM (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35	$ each
Amount Required	114	Number
Total Rep Parts Cost	4,460	Cost adjusted for freight & sales tax
Installation Labor	333	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**4,793**	
Annualized Cost	**2,651**	

Total Cost Replacement Parts (Bags) **4,793**

Design Flow	7,000	dscfm	7143	scfm
	77	Temp Deg F		
	2%	% Moisture		
	7,143	acfm		

Operating Cost Calculations				**Annual hours of operation:**		**8,000**	
				Utilization Rate:		**90.0%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	2	hr/8 hr shift	2,000	50,000	$/Hr, 2.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.5	Hr	1	hr/8 hr shift	1,000	17,500	$/Hr, 1.0 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	62.1	kW-hr	496,457	22,837	$/kW-hr, 36.4 kW; 8640 hr/yr
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/mscf, 40 scfm, 8000 hr/yr
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 7.16 gpm; 8000 hr/yr
Comp Air	0.27	Mscf	14.29	Mscfm	6,857	1,851	$/mscf, 100 scfm, 8640 hr/yr
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/T, 62 lb/lbmole, 0.76wt% NaOH, 8000 hr/yr
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/T, 62 lb/lbmole, 0.76wt% NaOH, 8000 hr/yr
SW Disposal	25	Ton	0.001	ton/hr	12	290	$/Ton, 0.300 gr/dscf, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.300 gr/dscf, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 7.16 gpm; 8000 hr/yr
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 39 ft3 of catalyst, 2 yr cat life
Rep Parts	35	bag	114.2857143	bags	2 yr life	2,651	795 bags, 2 yr life

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.3	gr/dscf	7,000	dscfm	NA	**11.7**	Use uncontrolled emission rate from enclosure case.
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99%	**0**	Currently assumes 99%.
Emission Reduction T/yr					**11.6**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	7,143	6	0.65	62.1	OAQPS Cost Cont Manual 6th ed - Eq 1.14

Table M-7: Multiclone - Material Handling - PM
BACT Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Equipment Cost		**88,752**
Instrumentation	10% of control device cost (A)	8,875
MN Sales Taxes	6.5% of control device cost (A)	5,769
Freight	5% of control device cost (A)	4,438
Purchased Equipment Total (B)	18%	**107,834**
Direct installation costs		
Foundations & supports	4% of purchased equip cost (B)	4,313
Handling & erection	40% of purchased equip cost (B)	43,133
Electrical	8% of purchased equip cost (B)	8,627
Piping	1% of purchased equip cost (B)	1,078
Insulation for ductwork	7% of purchased equip cost (B)	7,548
Painting	4% of purchased equip cost (B)	4,313
Installation Total	74%	**69,014**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Total Direct Capital Cost		**176,847**
Indirect Capital Costs		
Engineering	10% of purchased equip cost (B)	10,783
Construction and field expense	10% of purchased equip cost (B)	10,783
Contractor fees	10% of purchased equip cost (B)	10,783
Startup	1% of purchased equip cost (B)	1,078
Performance test	1% of purchased equip cost (B)	1,078
Contingencies	3% of purchased equip cost (B)	3,235
Total Indirect Capital Costs	45%	**37,742**
Total Capital Investment (TCI) = DC + IC		**214,589**
OPERATING COSTS		
Direct Operating Costs		
Operating Labor	25.00 $/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	12,500
Supervisor	15% of operator labor costs	1,875
Maintenance Labor	17.50 $/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity	8,750
Maintenance Materials	100% of maintenance labor costs	8,750
Replacement parts, bags		0
Utilities		
Electricity	0.05 $/kW-hr, 36.4 kW; 8640 hr/yr	228,370
Compressed Air	NA	-
Solid Waste Disposal	25.00 $/Ton, 0.300 gr/dscf, 8000 hr/yr	2,340
Total Annual Direct Operating Costs (DC)		**262,585**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	19,125
Administration (2% total capital costs)	2% of total capital costs (TCI)	4,292
Property tax (1% total capital costs)	1% of total capital costs (TCI)	2,146
Insurance (1% total capital costs)	1% of total capital costs (TCI)	2,146
Capital Recovery	9% for a 20- year equipment life and a 7% interest rate	20,256
Total Indirect Operating Costs		**47,964**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**310,550**
Pollutant Removed (tons/yr)[B]		**94**
Cost per ton of PM Removed		**3,318**

Notes & Assumptions

1 EPA Air Pollution Control Cost Manual 6th Ed 2002. Assumed same cost factors as baghouse.
2 Reduced erection to 40% and Const Field Exp to 10% to address simpler installation.
3 Reduced operator and maintenance hours to address simpler operation.
4 Design flow rate was increased by a factor of 10 to provide values large enough to create a cost estimate for multiclone. Original parameters were too small for vendor to provide estiamte for a multiclone.
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Table M-7: Multiclone - Material Handling - PM (Continued)

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors			
Primary Installation			
Interest Rate	7.0%		7
Equipment Life	20	years	
CRF	0.0944		

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts (Bags) **0**

Design Flow	7,000	dscfm	7143	scfm
	77	Temp Deg F		
	2%	% Moisture	**Scaled x10 to provide flow large enough for cost estimate**	
	7,143	acfm	71,429	acfm

Operating Cost Calculations — **Annual hours of operation: 8,000** — **Utilization Rate: 90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25	Hr	0.5	hr/8 hr shift	500	12,500	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.5	Hr	0.5	hr/8 hr shift	500	8,750	$/Hr, 0.5 hr/8 hr shift, 8000 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	620.6	kW-hr	4,964,571	228,370	$/kW-hr, 36.4 kW; 8640 hr/yr
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/mscf, 40 scfm, 8000 hr/yr
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 7.16 gpm; 8000 hr/yr
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/mscf, 100 scfm, 8640 hr/yr
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/T, 62 lb/lbmole, 0.76wt% NaOH, 8000 hr/yr
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/T, 62 lb/lbmole, 0.76wt% NaOH, 8000 hr/yr
SW Disposal	25	Ton	0.012	ton/hr	94	2,340	$/Ton, 0.300 gr/dscf, 8000 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.300 gr/dscf, 8000 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 7.16 gpm; 8000 hr/yr
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 39 ft3 of catalyst, 2 yr cat life
Rep Parts	33.72	bag	0	bags	2 yr life	0	795 bags, 2 yr life

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.3	gr/dscf	70,000	dscfm	NA	**117.0**	Use uncontrolled emission rate from enclosure case.
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				80%	**23**	Currently assumes 80%.
Emission Reduction T/yr					**93.6**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	71,429	6	0.65	620.6	OAQPS Cost Cont Manual 6th ed - Eq 1.14

Table M-8: Enclosure - Material Handling - PM
BACT Emission Control Cost Analysis

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Fabric Filter (EC) + bags + auxillary equipment		**23,000**
Instrumentation	10% of control device cost (A)	2,300
MN Sales Taxes	6.5% of control device cost (A)	1,495
Freight	5% of control device cost (A)	1,150
Purchased Equipment Total (B)	18%	**27,945**
Direct installation costs		
Foundations & supports	4% of purchased equip cost (B)	1,118
Handling & erection	40% of purchased equip cost (B)	11,178
Electrical	8% of purchased equip cost (B)	2,236
Piping	1% of purchased equip cost (B)	279
Insulation for ductwork	7% of purchased equip cost (B)	1,956
Painting	4% of purchased equip cost (B)	1,118
Installation Total	74%	**17,885**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Total Direct Capital Cost		**45,830**
Indirect Capital Costs		
Engineering	10% of purchased equip cost (B)	2,795
Construction and field expense	10% of purchased equip cost (B)	2,795
Contractor fees	10% of purchased equip cost (B)	2,795
Startup	1% of purchased equip cost (B)	279
Performance test	1% of purchased equip cost (B)	279
Contingencies	3% of purchased equip cost (B)	838
Total Indirect Capital Costs	45%	**9,781**
Total Capital Investment (TCI) = DC + IC		**55,611**
OPERATING COSTS		
Direct Operating Costs		
Operating Labor	25.00 $/Hr, 0.1 hr/8 hr shift, hr/yr, 0.0% of capacity	2,500
Supervisor	15% of operator labor costs	375
Maintenance Labor	17.50 $/Hr, 0.1 hr/8 hr shift, hr/yr, 0.0% of capacity	1,750
Maintenance Materials	100% of maintenance labor costs	1,750
Replacement parts, bags		0
Utilities		
Electricity	0.05 $/kW-hr, 36.4 kW; 8640 hr/yr	34,303
Compressed Air	NA	-
Solid Waste Disposal	NA	-
Total Annual Direct Operating Costs (DC)		**40,678**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	3,825
Administration (2% total capital costs)	2% of total capital costs (TCI)	1,112
Property tax (1% total capital costs)	1% of total capital costs (TCI)	556
Insurance (1% total capital costs)	1% of total capital costs (TCI)	556
Capital Recovery	9% for a 20- year equipment life and a 7% interest rate	5,249
Total Indirect Operating Costs		**11,299**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**51,977**
Pollutant Removed (tons/yr)[B]		**11**
Cost per ton of PM Removed		**4,586**

Notes & Assumptions

1 EPA Air Pollution Control Cost Manual 6th Ed 2002. Assumed same cost factors as baghouse.
2 Reduced erection to 40% and Const Field Exp to 10% to address simpler installation.
3 Reduced operator and maintenance hours to address simpler operation.
4
5
6
7
8

Table M-8: Enclosure - Material Handling - PM (Continued)

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	7
Equipment Life	20 years	
CRF	0.0944	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor		10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts (Bags) **0**

Design Flow	7,000	dscfm	7143 scfm
	77	Temp Deg F	
	2%	% Moisture	
	7,143	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,000**; **Utilization Rate:** **90.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Op Labor	25	Hr	0.1	hr/8 hr shift	100	2,500	$/Hr, 0.1 hr/8 hr shift, hr/yr, 0.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.5	Hr	0.1	hr/8 hr shift	100	1,750	$/Hr, 0.1 hr/8 hr shift, hr/yr, 0.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	93.2	kW-hr	745,720	34,303	$/kW-hr, 36.4 kW; 8640 hr/yr
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/mscf, 40 scfm, 8000 hr/yr
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 7.16 gpm; 8000 hr/yr
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/mscf, 100 scfm, 8640 hr/yr
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/T, 62 lb/lbmole, 0.76wt% NaOH, 8000 hr/yr
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/T, 62 lb/lbmole, 0.76wt% NaOH, 8000 hr/yr
SW Disposal	0	Ton	0.857	ton/hr	6,857	0	$/Ton, 0.005 lb PM/ton taconite, hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.005 lb PM/ton taconite, hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 7.16 gpm; 8000 hr/yr
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 39 ft3 of catalyst, 2 yr cat life
Rep Parts	33.72	bag	0	bags	2 yr life	0	795 bags, 2 yr life

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Emission Factor	Unit of Measure	Load Rate	Unit of Measure	Control Eff. %	Emis Rate T/yr	Comments/Notes
Uncontrolled Emission Rate						
4.67E-03	lb PM/ton taconite	5,000,000	ton/yr	NA	**11.7**	Uncontrolled EF is based on a maximum wind speed of 15 mph per EPA AP-42 13.2.4
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Load Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
1.38E-04	lb PM/ton taconite	5,000,000	ton/yr	NA	**0.3**	Controlled EF is based on a maximum wind speed of 1 mph per EPA AP-42 13.2.4.
Emission Reduction T/yr					**11.3**	
				Estimated % Control =	97%	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	0	6	0.65	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.14

Table M-8: Enclosure - Material Handling - PM (Continued)

Calculate Emission Factors using EPA AP-42 13.2.4: Aggregate Handling and Storage Piles
EQ: E = k*0.0032*[(U/5)^1.3/(M/2)^1.4] [=] lb PM/ton ore.

Controlled Conditions - EF
Given:

k =	0.35	Particle Size Multiplier for < 10 mm (unitless)
U =	1	mph, mean wind speed, (AP-42 range 1.3-15 mph)
M =	2.0	%, material moisture content, (AP-42 range 0.05-2.0)
E =	1.38E-04	lb PM/ton taconite

Uncontrolled Conditions - EF
Given:

k =	0.35	Particle Size Multiplier for < 10 mm (unitless)
U =	15	mph, mean wind speed, (AP-42 range 1.3-15 mph)
M =	2.0	%, material moisture content, (AP-42 range 0.05-2.0)
E =	4.67E-03	lb PM/ton taconite

ATTACHMENT N

Control Technology Literature Search References

Literature Source/Author	Source Type	Pollutant	Technology	Control Efficiency	Operating Limits	Consumables	Waste	Other Special Requirements (e.g. Blowers/Gas Conditioning for ESP's)	Comments/Concerns
EPA-600/R-00-093	Boiler	SOx	Wet FGD - limestone	52-98%	scaling problems w/o blowing air into absorbent slurry	Limestone	By-Product Gypsum	blowers (limit scaling problems)	Adding Dibasic Acid (DBA) can improve SO2 removal. See Chpts. 4,5 &6.
EPA-600/R-00-093	Boiler	SOx	Wet FGD - Ammonia	≥ 95%		Ammonia	Ammonia Sulfate, Aerosol emissions		Offers the advantage of ammonium sulfate by-product that can be used as fertilizer. Aerosol emissions are a concern.
EPA-600/R-00-093	Boiler	SOx	Dry FGD	≥ 90%	high sulfur coal affects CE.				Best for sources burning low to medium sulfur coal.
Clean Coal Program - DOE	Kiln Flue Gas	SOx	Cement Kiln Flue Gas Recovery Scrubber	89.20%		Caustic. Limestone	Wastewater		Produces potassium-based fertilizer by-products
Clean Coal Program - DOE		NOx	Cement Kiln Flue Gas Recovery Scrubber	18.80%		Caustic. Limestone	Wastewater		Produces potassium-based fertilizer by-products
EPA Docket A-96-56, II-A-03	Boiler - Coal, Oil or Gas Fired	NOx	Combustion Control	40-70%	0.15 lb/MMBTU NOx limit				Combustion controls include low-NOx burners, overfire air, and gas recirculation.
EPA Docket A-96-56, II-A-03	Boiler - Coal, Oil or Gas Fired	NOx	SCR	80-90%	0.15 lb/MMBTU NOx limit		Spent Catalyst		Technically feasible for most types of boilers.
EPA Docket A-96-56, II-A-03	Boiler - Coal, Oil or Gas Fired	NOx	SNCR	30-50%	0.15 lb/MMBTU NOx limit				
RBLC - Kiln	Rotary Kiln	PM	Fabric Filter	99%			Solid Waste		
RBLC - Kiln	Rotary Kiln	NOx	Low NOx Burners, SNCR		8 lbs/ton klinker	Natural Gas			
RBLC - Kiln	Rotary Kiln	SOx	Wet Scrubber		12 lbs/ton klinker		Wastewater		
RBLC - Kiln	Incinerator, Rotary Kiln, Hazardous Waste	NOx	Abatement rxn. Chamber with urea	20%		Urea			
RBLC - Kiln	Incinerator, Rotary Kiln, Hazardous Waste	PM	Venturi Scrubber	99.86%		Limestone, Caustic	Wastewater		
RBLC - Kiln	Rotary Kiln - Cement	PM	ESP				Solid Waste		
RBLC - Kiln	Rotary Kiln - Cement	SOx	Fuel limits			None			
RBLC - Kiln	Fugitive - Material Handling and Storage	PM	EPA Method 5, 9			None			
RBLC - Kiln	Material Handling, Lime	PM	Wet Suppression, covers & partial enclosure	95.00%	5.6 TPY				
AWMA Glass Plant	Furnace	PM	Furnace Design						
AWMA Glass Plant	Furnace	PM	ESP				Solid Waste		
AWMA Glass Plant	Furnace	PM	Baghouse			Filters	Solid Waste		
AWMA NOx Paper #1		NOx	SCR	90-97%		Catalyst	Spent Catalyst		See Tables I & II of AWMA Doc.

Literature Source/Author	Source Type	Pollutant	Technology	Control Efficiency	Operating Limits	Consumables	Waste	Other Special Requirements (e.g. Blowers/Gas Conditioning for ESP's)	Comments/Concerns
AWMA NOx Paper #1		NOx	ULNB	80.00%		Natural Gas	None		See Tables I & II of AWMA Doc.
AWMA NOx Paper #1		NOx	Different levels of burners			Natural Gas	None		See Tables I & II of AWMA Doc.
AWMA NOx Paper #1		NOx	Flue Gas Recirculation	55%					See Tables I & II of AWMA Doc.
AWMA NOx Paper #1		NOx	SNCR	50-70%					See Tables I & II of AWMA Doc.
AWMA NOx Paper #1		NOx	Catalytic Scrubbing	70%		Catalyst	Spent Catalyst		See Tables I & II of AWMA Doc.
NOx Controls for Existing Utility Boilers	Wall Fired Boiler	NOx	OFA	70 - 80 %					
NOx Controls for Existing Utility Boilers	Wall Fired Boiler	NOx	LNB	45 - 60%		Natural Gas	None		
NOx Controls for Existing Utility Boilers	Wall Fired Boiler	NOx	LNB+OFA	35 - 55%		Natural Gas	None		
NOx Controls for Existing Utility Boilers	Tangential Fired Boiler	NOx	LNB+SOFA	30 - 45 %		Natural Gas	None		
NOx Controls for Existing Utility Boilers	Wall Fired Boiler	NOx	SNCR	50 - 65 %			None		
NOx Controls for Existing Utility Boilers	Wall Fired Boiler	NOx	SCR	15 - 25%		Catalyst	Spent Catalyst		
NOx Controls for Existing Utility Boilers	Tangential Fired Boiler	NOx	SNCR	0.30 - 0.40			None		
NOx Controls for Existing Utility Boilers	Tangential Fired Boiler	NOx	SCR	0.10 - 0.15		Catalyst	Spent Catalyst		
NOx Controls for Existing Utility Boilers	Boiler	NOx	NGR	0.50 - 0.70		None	None		
NOx Controls for Existing Utility Boilers	Wall Fired Boiler - fuel: Oil, Gas	NOx	BOOS	0.30 - 0.35		None	None		
NOx Controls for Existing Utility Boilers	Wall Fired Boiler - fuel: Oil, Gas	NOx	FGR	0.25 - 0.35		None	None		
NOx Controls for Existing Utility Boilers	Wall Fired Boiler - fuel: Oil, Gas	NOx	LNB	0.25 - 0.30		Natural Gas	None		

Literature Source/Author	Source Type	Pollutant	Technology	Control Efficiency	Operating Limits	Consumables	Waste	Other Special Requirements (e.g. Blowers/Gas Conditioning for ESP's)	Comments/Concerns
NOx Controls for Existing Utility Boilers	Wall Fired Boiler - fuel: Oil, Gas	NOx	LNB+OFA+FGR	0.10 - 0.20		Natural Gas	None		
NOx Controls for Existing Utility Boilers	Tangential Fired Boiler - fuel: Oil, Gas	NOx	BOOS	0.20 - 0.25		None	None		
NOx Controls for Existing Utility Boilers	Tangential Fired Boiler - fuel: Oil, Gas	NOx	LNB	0.15 - 0.25		Natural Gas	None		
NOx Controls for Existing Utility Boilers	Wall Fired Boiler - fuel: Oil, Gas	NOx	SNCR	0.25 - 0.30		None	None		
NOx Controls for Existing Utility Boilers	Wall Fired Boiler - fuel: Oil, Gas	NOx	SCR	0.10 - 0.15		Catalyst	Spent Catalyst		
NOx Controls for Existing Utility Boilers	Tangential Fired Boiler - fuel: Oil, Gas	NOx	SNCR	0.15 - 0.20		None	None		
NOx Controls for Existing Utility Boilers	Tangential Fired Boiler - fuel: Oil, Gas	NOx	SCR	0.05 - 0.10		Catalyst	Spent Catalyst		
RBLC- National Steel		SOx			H2S CONCENTRATION OF COKE OVEN GAS (FUEL) LIMITED TO 2.64 GR/DSCF 2033 TPY	None	None		
RBLC- National Steel		NOx		Emission Limit: Total limit of both gases:	Rich Gas - 493.8 TPY Lean Gas - 581.9 959.5 tpy	None	None		RICH' MODE (85% COKE OVEN GAS)TESTS YIELD A FACTOR OF 0.002 LB/NOX PER LB OF COAL. A SEPARATE LIMIT FOR 'LEAN' MODE (80% BLAST FURNACE GAS/WITH BALANCE COKE OVEN GAS) OPERATION.
RBLC - ISPAT		NOx	Low NOx Burners		FUEL USE IS LIMITED TO 270 MMBTU/HR FOR ALL EU26 BURNERS COMBINED (4 STACKS) IN ADDITION TO THE USE OF EXISTING LOW NOX BURNERS. 11 CONTROL OPTIONS EXAMINED.	Natural Gas	None		A PSD Permit, Issued on 9/25/87, Gave an Erroneous NOx Emission Limit for the Indurating Machine, Which Would Be Fitted with Low NOx Burners. It Is Now Corrected with the Facility's Title V Permit, after a Thorough Backward- Looking PSD Review. The Limit Is Raised, Without Any New Add-on Control.

Literature Source/Author	Source Type	Pollutant	Technology	Control Efficiency	Operating Limits	Consumables	Waste	Other Special Requirements (e.g. Blowers/Gas Conditioning for ESP's)	Comments/Concerns
Dry Low NOx Memo - Combined Cycle Natural Gas Turbines	NG Turbines	NOx	SCR	80 - 90%	2.5 - 4.5 ppm	Catalyst	Spent Catalyst		SCR is most effective within a certain temperature range and higher or lower temperatures and other operating conditions can cause some of the NOx and ammonia to pass through the catalyst without reacting. Catalysts degrade eventually, and that also can cause ammonia to pass through the catalyst unreacted. The use of SCR systems results in spent catalyst waste. Note that using more catalyst results in lower NOX and ammonia slip emissions, but higher costs and more spent catalyst waste.

Notes

FGD = Flue Gas Desulfurization
SCR = Selective Catalytic Reduction
SNCR = Selective Non-Catalytic Reduction
ESP = Electrostatic Precipitator
ULNB = Ultra Low NOx Burner
LNB = Low NOx Burner
OFA = "Overfire Air", a NOx combustion modification technology.
SOFA = "Separate Overfire Air", a NOx combustion modification technology.
BOOS = Burners Out of Service
FGR = Flue Gas Recirculation
NGR = Natural Gas Reburning

ATTACHMENT O

Applicable Minnesota Air Regulations

7007.0800 PERMIT CONTENT.

Subpart 1. **Scope.** The agency shall include the permit conditions specified in this part in all permits, except where the requirement states that it applies only to part 70 permits or only to state permits. The permit shall specify and reference the origin of and the authority for each term or condition, and shall identify any difference in form from the requirement giving rise to the condition. Nothing in this part shall be read to limit the agency's authority to put additional or more stringent terms in a permit, to conduct inspections, or to request information.

Subp. 2. **Emission limitations and standards.** The permit shall include emissions limitations, operational requirements, and other provisions needed to ensure compliance with all applicable requirements at the time of permit issuance. The permit shall also include any condition the agency determines to be necessary to protect human health and the environment. The permit shall state that, where another applicable requirement of the act is more stringent than any applicable requirement of regulations promulgated under title IV of the act (Acid Deposition Control), both provisions shall be incorporated into the permit and shall be enforceable by the administrator.

Subp. 3. **Emissions units covered by permit.** The permit shall cover any emissions unit within the stationary source for which there is an applicable requirement, and any unit which the agency believes should be covered in order to protect human health and the environment. However, if a stationary source is not a major source and the sole reason it is required to have a permit is because it is subject to federal standards described under part 7007.0250, subpart 2, then the permit shall only cover emissions units regulated by those federal standards. The permit shall include applicable requirements for fugitive emissions in the same manner as stack emissions, regardless of whether the source category in question is included in the list of sources contained in the definition of major source in part 7007.0200, subpart 2.

Subp. 4. **Monitoring.** The agency shall include the following monitoring requirements in all permits:

A. The permit shall require the permittee to comply with all emissions monitoring and analysis procedures or test methods required under the applicable requirements, including any procedures and methods promulgated pursuant to section 114(a)(3) or 504(b) of the act.

B. For part 70 permits, where the applicable requirements do not require periodic testing or instrumental or noninstrumental monitoring (which may consist of recordkeeping designed to serve as monitoring), the permit shall require the permittee to conduct periodic monitoring sufficient to determine whether the stationary source is in compliance with applicable requirements. The monitoring requirements shall be designed to yield reliable data from the relevant time period that are representative of the stationary source's operation, and shall require the permittee to use terms, test methods, units, averaging periods, and other statistical conventions that are consistent with the emissions limitations and standards contained in the permit, and with other applicable requirements. Recordkeeping provisions may be sufficient to meet the requirements of this item.

C. For state permits, where periodic testing or instrumental or noninstrumental monitoring (which may consist of recordkeeping designed to serve as monitoring) is not required by item A, the permit shall include monitoring requirements sufficient to determine whether a stationary source is in compliance with applicable requirements; if the agency finds that such monitoring is warranted by:

(1) the likelihood of noncompliance;

(2) the environmental impact of noncompliance; or

(3) the likelihood that noncompliance could not be detected using means other than monitoring.

D. As necessary, the permit shall require the permittee to install, use, and maintain monitoring equipment or use monitoring methods.

Subp. 5. **Recordkeeping.** The permit shall incorporate all applicable requirements related to recordkeeping and require the permittee to maintain adequate records, including at least the following:

A. A requirement that the permittee maintain records adequate to document compliance at the stationary source, including at a minimum:

(1) the date, place, as defined in the permit, and time of sampling or measurements;

(2) the date or dates analyses were performed;

(3) the company or entity that performed the analyses;

(4) the analytical techniques or methods used;

(5) the results of such analyses; and

(6) the operating conditions existing at the time of sampling or measurement.

B. A requirement that the permittee maintain records describing any modification made at the stationary source under parts 7007.1250 and 7007.1350, as required by those provisions, but not otherwise regulated under the permit, and the emissions resulting from those changes.

C. A requirement that the permittee retain records of all monitoring data and support information for a period of five years, or longer as specified by the commissioner, from the date of the monitoring sample, measurement, or report. Support information includes all calibration and maintenance records and all original recordings for continuous monitoring instrumentation, and copies of all reports required by the permit. Records shall be kept at the stationary source unless the permit allows otherwise.

D. A requirement that the permittee retain copies of deviation reports required by subpart 6 for a period of five years, or longer if requested by the commissioner, from the date of submittal of the report to the agency.

Subp. 6. **Reporting.** The permit shall require the permittee to submit to the agency the reports described in this subpart. The permit shall require that all reports be certified by a responsible official consistent with part 7007.0500, subpart 3.

A. Deviation reporting time frames are described in subitems (1) and (2).

(1) For deviations that endanger human health or the environment, the permit shall require the permittee to notify the commissioner as required in part 7019.1000, subpart 1.

(2) For all other deviations, the permit shall require the permittee to submit a deviation report, on a form approved by the commissioner, at least semiannually. The report is due whether or not a deviation occurred during the reporting period. The midyear deviations report, covering deviations which occurred during the period from January 1 to June 30, is due by July 30 of each year and the end-of-year deviations report, covering deviations which occurred during the period from July 1 to December 31, is due by January 30 of each year.

B. All part 70 permits shall require the permittee to submit progress reports at least every six months for any stationary source required to have a compliance schedule under part 7007.0500, subpart 2, item K, subitem (4). Such progress reports shall contain the deadlines for achieving the activities, milestones, or compliance required in the compliance schedule and dates when such activities, milestones, or compliance were actually achieved. If any deadlines in the schedule of compliance were not or will not be met, the report shall note that, explain why, and include any preventive or corrective measures that have been or will be adopted as a result.

C. The permit shall require submittal of an annual compliance certification by January 31 of each year to the agency. In the case of part 70 permits, compliance certifications shall be submitted to the administrator as well as the agency, unless the administrator agrees that the submittals are not necessary. The certification shall be on a form approved by the commissioner and shall contain the following:

(1) the facility name and permit number;

(2) identification of the calendar year that the report covers;

(3) identification of deviation reports submitted covering the calendar year including the name of report (i.e. DRF-1 or DRF-2), the period covered by the report, and the date of the cover letter accompanying the report;

(4) identification of any noncompliance with applicable requirements or a permit condition that has not been identified in deviation reports submitted to the agency covering the calendar year;

(5) a certification that meets the requirements of part 7007.0500, subpart 3;

(6) the signature and title of a responsible official as defined in part 7007.0100, subpart 21; and

(7) additional requirements as may be specified pursuant to sections 114(a)(3) and 504(b) of the act.

Notwithstanding any other provision in an applicable requirement, for the purpose of submission of compliance certifications under this item, the owner or operator is not prohibited from using the following in addition to any specified methods:

(a) a monitoring protocol approved for the source pursuant to Code of Federal Regulations, title 40, part 64, as amended; and

(b) any other monitoring method incorporated into a permit issued under this chapter.

D. All progress reports and compliance documents described in this subpart are available for public inspection and copying at the agency upon request, subject to the provisions of part 7000.1200 and Minnesota Statutes, chapter 13, and section 116.075.

E. For deviations caused by emergencies, as defined in part 7007.1850, the permittee may assert an affirmative defense only if it meets all the requirements of part 7007.1850, which includes notifying the agency within two working days of when the emission limitations were exceeded due to the emergency.

Subp. 7. **Prohibition on exceedance of allowances.** For affected sources, the agency shall include a permit condition prohibiting emissions exceeding any allowances that the stationary source lawfully holds under title IV of the act or the regulations promulgated thereunder, except as follows:

A. No permit amendment shall be required for increases in emissions that are authorized by allowances acquired pursuant to the acid rain program, provided that such increases do not require a permit amendment under any other applicable requirement.

B. No limit shall be placed on the number of allowances held by the stationary source. The stationary source may not, however, use allowances as a defense to noncompliance with any other applicable requirement.

C. Any such allowance shall be accounted for according to the procedures established in Code of Federal Regulations, title 40, part 73, as amended.

Subp. 8. **Fee requirement.** The permit shall require payment of annual fees by owners or operators of a stationary source required to pay annual fees due under part 7002.0025.

Subp. 9. **Additional compliance requirements.** All permits shall contain the following elements with respect to compliance:

A. inspection and entry requirements that require that, upon presentation of credentials and other documents as may be required by law, the permittee shall allow the agency, or an authorized representative or agent of the agency, to perform the following:

(1) enter upon the permittee's premises where the stationary source is located or activity is conducted, or where records must be kept under the conditions of the permit;

(2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;

(3) inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit. For purposes of this subpart, reasonable times include any time that the stationary source is operating; and

(4) sample or monitor any substances or parameters at any location:

(a) at reasonable times, for the purposes of assuring compliance with the permit or applicable requirements; or

(b) as otherwise authorized by the act or state law;

B. a schedule of compliance if one is required under part 7007.0500, subpart 2, item K, meeting the description of that part; and

C. provisions establishing the permit shield described in part 7007.1800.

Nothing in this subpart shall be read to limit the agency's authority under Minnesota Statutes, section 116.091, and section 114 of the act (Recordkeeping, Inspections, Monitoring, and Entry) or other law.

Subp. 10. **Emissions trading.**

A. If requested by a permit applicant, the agency shall include provisions allowing the permittee to trade emissions increases and decreases that occur within the permitted facility. No title I modification may be made using this provision, and the trade may not result in the exceedance of any facility-wide emission limit in the permit. The agency shall make such trading available to the permittee only if it determines that all of the following are true:

(1) the unit-specific limits above which the permittee wishes to increase emissions were established solely to keep the stationary source as a whole from being subject to an applicable requirement described in part 7007.0100, subpart 7, items A to K, and are independent of otherwise applicable requirements;

(2) the stationary source's total emissions can be limited equally well, and compliance with applicable requirements may still be assured, by allowing the proposed trading scenario; and

(3) the permit establishes replicable procedures to ensure the emission trades are quantifiable and enforceable.

B. The permit shall require the permittee to provide the agency in writing at least seven working days before making the emissions trade the written notification described in this item. The notice shall state when the trade will be made and describe the change in emissions that will result. The notice shall also describe how these increases and decreases in emissions will comply with the terms and conditions of the permit. The permittee and the agency shall each append the notice to its copy of the stationary source's permit.

Subp. 11. **Alternative scenarios.** Terms and conditions allowing for reasonably anticipated alternative operating scenarios identified by the stationary source in its application. Such terms and conditions shall:

A. require the stationary source, contemporaneously with making a change from one operating scenario to another, to record in a log at the permitted facility a record of the scenario under which it is operating; and

B. ensure that the operation under each such alternative scenario complies with all applicable requirements and the requirements of parts 7007.0100 to 7007.1850.

Subp. 12. **Operation in more than one location.** If requested by the applicant, the permit may allow a stationary source to be operated in more than one location during the course of the permit. No affected source shall be allowed this option. If more than one location is authorized, the permit shall include the following:

A. identification of all geographic areas where the stationary source is authorized to operate during the course of the permit;

B. conditions that will assure compliance with all applicable requirements at all authorized locations;

C. requirements that the owner or operator notify the agency at least ten days in advance of each change in location, providing the exact location where the source will operate for all part 70 permits and at least 48 hours in advance of each change in location for all other state permits; and

D. conditions that assure compliance with all other provisions of parts 7007.0100 to 7007.1850.

Subp. 13. **Permit duration.** Each permit shall specify the duration of the permit, or state that the permit is nonexpiring.

Subp. 14. **Operation of control equipment.** If the commissioner determines that such provisions would substantially improve the likelihood of future permit compliance, the permit may specify operating and maintenance requirements for each piece of control equipment located at the stationary source or require the permittee to maintain an operation and maintenance plan on site.

Subp. 15. **Terms to include in reissuance.** The permit shall indicate the terms that must be included in any reissuance of the permit under part 7007.0450, subpart 3.

Subp. 16. **General conditions.** Permits issued by the agency under parts 7007.0100 to 7007.1850 shall include the following general conditions, either expressly or by reference to this subpart.

A. Unchallenged provisions of this permit remain valid despite any successful challenges to specific portions of the permit.

B. The permittee must comply with all conditions of the permit. Any permit noncompliance constitutes a violation of the state law and, if the provision is federally enforceable, of the act. Such violation is grounds for enforcement action by the agency or the EPA; or for permit termination, revocation and reissuance, or amendment; or for denial of a permit reissuance application.

C. It is not a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

D. This permit may be reopened and amended or revoked for cause as provided in parts 7007.1600 to 7007.1700. The filing of a request by the permittee for a permit amendment, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition, except as specifically provided in part 7007.1450, subpart 7.

E. This permit does not convey any property rights of any sort, or any exclusive privilege.

F. The permittee shall furnish to the agency, within a reasonable time, any information that the agency may request in writing to determine whether cause exists for reopening and amending or revoking the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the agency copies of records required to be kept by the permittee.

G. The agency's issuance of a permit does not release the permittee from any liability, penalty, or duty imposed by Minnesota or federal statutes or rules or local ordinances, except the obligation to obtain the permit or as specifically provided in the permit shield provision and part 7007.1800.

H. The agency's issuance of a permit does not prevent the future adoption by the agency of pollution control rules, standards, or orders more stringent than those now in existence and does not prevent the enforcement of these rules, standards, or orders against the permittee.

I. The agency's issuance of a permit does not obligate the agency to enforce local laws, rules, or plans beyond that authorized by Minnesota statutes.

J. The permittee shall at all times properly operate and maintain the facilities and systems of treatment and control and the appurtenances related to them which are installed or used by the permittee to achieve compliance with the conditions of the permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures.

K. The permittee may not knowingly make a false or misleading statement, representation, or certification in a record, report, plan, or other document required to be submitted to the agency or to the commissioner by the permit. The permittee shall immediately upon discovery report to the commissioner an error or omission in these records, reports, plans, or other documents. The permittee may not falsify, tamper with, render inaccurate, or fail to install any monitoring device or method required to be maintained or followed by the permit.

L. The permittee shall, when requested by the commissioner, submit within a reasonable time any information and reports that are relevant to pollution or the activities authorized under this permit.

M. If the permittee discovers, through any means, including notification by the agency, that noncompliance with a condition of the permit has occurred, the permittee shall immediately take all reasonable steps to minimize the adverse impact on human health or the environment resulting from the noncompliance.

N. The permit is not transferable to any person except as provided in part 7007.1400, subpart 1, item E.

O. The permit authorizes the permittee to perform the activities described in the permit under the conditions of the permit. In issuing the permit, the state and agency assume no responsibility for damages to persons, property, or the environment caused by the activities of the permittee in the conduct of its actions, including those activities authorized, directed, or undertaken under the permit. To the extent the state and agency may be liable for the activities of its employees, that liability is explicitly limited to that provided in the Tort Claims Act, Minnesota Statutes, section 3.736.

STAT AUTH: MS s 116.07

HIST: 18 SR 1059; 19 SR 1775; 20 SR 2316; 22 SR 1237

7011.0150 PREVENTING PARTICULATE MATTER FROM BECOMING AIRBORNE.

No person shall cause or permit the handling, use, transporting, or storage of any material in a manner which may allow avoidable amounts of particulate matter to become airborne.

No person shall cause or permit a building or its appurtenances or a road, or a driveway, or an open area to be constructed, used, repaired, or demolished without applying all such reasonable measures as may be required to prevent particulate matter from becoming airborne. All persons shall take reasonable precautions to prevent the discharge of visible fugitive dust emissions beyond the lot line of the property on which the emissions originate. The commissioner may require such reasonable measures as may be necessary to prevent particulate matter from becoming airborne including, but not limited to, paving or frequent clearing of roads, driveways, and parking lots; application of dust-free surfaces; application of water; and the planting and maintenance of vegetative ground cover.

STAT AUTH: MS s 116.07

HIST: L 1987 c 186 s 15; 18 SR 614; 20 SR 2316

7011.0610 STANDARDS OF PERFORMANCE FOR FOSSIL-FUEL-BURNING DIRECT HEATING EQUIPMENT.

Subpart 1. **Particulate limitations.** Particulate limitations:

A. No owner or operator of any direct heating equipment shall cause to be discharged into the atmosphere from the direct heating equipment any gases which:

(1) contain particulate matter in excess of the limits allowed by parts 7011.0700 to 7011.0735; or

(2) exhibit greater than 20 percent opacity, except for one six-minute period per hour of not more than 60 percent opacity. An exceedance of this opacity standard occurs whenever any one-hour period contains two or more six-minute periods during which the average opacity exceeds 20 percent or whenever any one-hour period contains one or more six-minute periods during which the average opacity exceeds 60 percent.

B. No owner or operator of an existing gray iron cupola with a melting capacity of less than 1-1/2 tons per hour shall allow emissions which exceed 0.3 grain per standard cubic foot, dry basis, and the owner or operator shall incinerate all gases, vapors, and gas entrained effluents from such cupolas at a temperature of not less than 1,200 degrees Fahrenheit for a period of not less than 0.3 seconds. The owner or operator of any other gray iron cupola shall meet the requirements of item A.

Subp. 2. **Sulfur oxide limitations.** Sulfur oxide limitations:

A. Within Minneapolis-Saint Paul Air Quality Control Region. No owner or operator of direct heating equipment located within the Minneapolis-Saint Paul Air Quality Control Region shall cause to be discharged into the atmosphere from such equipment any gases which contain sulfur dioxide:

(1) in excess of three pounds per million Btu heat input if a solid fossil fuel is burned or 1.6 pounds per million Btu heat input if a liquid fossil fuel is burned, if the total rated heat input of all indirect and direct heating equipment of the owner or operator at that particular location exceeds 250 million Btu per hour;

(2) in excess of four pounds per million Btu heat input if a solid fossil fuel is burned or two pounds per million Btu heat input if a liquid fossil fuel is burned, if the total rated heat input of all indirect and direct heating equipment of the owner or operator at that particular location is equal to or less than 250 million Btu per hour.

B. Outside Minneapolis-Saint Paul Air Quality Control Region. No owner or operator of direct heating equipment located outside the Minneapolis-Saint Paul Air Quality Control Region shall cause to be discharged into the atmosphere from such equipment any gases which contain sulfur dioxide in excess of four pounds per million Btu heat input if a solid fossil fuel is burned or two pounds per million Btu heat input if a liquid fossil fuel is burned, if the total rated heat input of all indirect and direct heating equipment of the owner or operator at that particular location is greater than 250 million Btu per hour.

STAT AUTH: MS s 116.07

HIST: 18 SR 614; 23 SR 145

7011.0710 STANDARDS OF PERFORMANCE FOR PRE-1969 INDUSTRIAL PROCESS EQUIPMENT.

Subpart 1. **Prohibited discharge of gases.** No owner or operator of any industrial process equipment which was in operation before July 9, 1969, shall cause to be discharged into the atmosphere from the industrial process equipment any gases which:

A. in any one hour contain particulate matter in excess of the amount permitted in part 7011.0730 for the allocated process weight; provided that the owner or operator shall not be required to reduce the particulate matter emission below the concentration permitted in part 7011.0735 for the appropriate source gas volume; provided further that regardless of the mass emission permitted by part 7011.0730, the owner or operator shall not be permitted to emit particulate matter in a concentration in excess of 0.30 grains per standard cubic foot of exhaust gas; or

B. exhibit greater than 20 percent opacity, except for one six-minute period per hour of not more than 60 percent opacity. An exceedance of this opacity standard occurs whenever any one-hour period contains two or more six-minute periods during which the average opacity exceeds 20 percent or whenever any one-hour period contains one or more six-minute periods during which the average opacity exceeds 60 percent.

Subp. 2. **Compliance.** The owner or operator of any industrial process equipment which was in operation before July 9, 1969, which has control equipment with a collection efficiency of not less than 99 percent by weight shall be considered in compliance with the requirements of subpart 1, item A.

Subp. 3. **Equipment located outside of Saint Paul, Minneapolis, and Duluth.** The owner or operator of any industrial process equipment which was in operation before July 9, 1969, which is located outside the Minneapolis-Saint Paul Air Quality Control Region and the city of Duluth, which is located not less than one-fourth mile from any residence or public roadway, and which has control equipment with a collection efficiency of not less than 85 percent by weight, and the operation of the entire emission facility does not cause a violation of the ambient air quality standards, shall be considered in compliance with the requirements of subpart 1, item A.

STAT AUTH: MS s 116.07

HIST: 18 SR 614; 23 SR 145

7011.0715 STANDARDS OF PERFORMANCE FOR POST-1969 INDUSTRIAL PROCESS EQUIPMENT.

Subpart 1. **Prohibited discharge of gases.** No owner or operator of any industrial process equipment which was not in operation before July 9, 1969, shall cause to be discharged into the atmosphere from the industrial process equipment any gases which:

A. in any one hour contain particulate matter in excess of the amount permitted in part 7011.0730 for the allocated process weight; provided that the owner or operator shall not be required to reduce the particulate matter emission below the concentration permitted in part 7011.0735 for the appropriate source gas volume; provided that regardless of the mass emission permitted by part 7011.0730, the owner or operator shall not be permitted to emit particulate matter in a concentration in excess of 0.30 grains per standard cubic foot of exhaust gas; or

B. exhibit greater than 20 percent opacity.

Subp. 2. **Compliance.** The owner or operator of any industrial process equipment which was not in operation before July 9, 1969, which has control equipment with a collection efficiency of not less than 99.7 percent by weight shall be considered in compliance with the requirements of subpart 1, item A.

Subp. 3. **Equipment located outside of Saint Paul, Minneapolis, and Duluth.** The owner or operator of any industrial equipment which was in operation after July 9, 1969, which is located outside the Minneapolis-Saint Paul Air Quality Control Region and the city of Duluth, which is located not less than one-fourth mile from any residence or public roadway, and which has control equipment with a collection efficiency of not less than 85 percent by weight, and the operation of the entire emission facility does not cause a violation of the ambient air quality standards, shall be considered in compliance with the requirements of subpart 1, item A.

STAT AUTH: MS s 116.07 subd 4

HIST: 18 SR 614

7011.1150 STANDARDS OF PERFORMANCE FOR NEW COAL PREPARATION PLANTS.

Code of Federal Regulations, title 40, part 60, subpart Y, as amended, entitled "Standards of Performance for Coal Preparation Plants," is adopted and incorporated by reference.

STAT AUTH: MS s 116.07

HIST: 18 SR 580

7011.2700 STANDARDS OF PERFORMANCE FOR NEW METALLIC MINERAL PROCESSING PLANTS.

Code of Federal Regulations, title 40, part 60, subpart LL, as amended, entitled "Standards of Performance for Metallic Mineral Processing Plants," is adopted and incorporated by reference.

STAT AUTH: MS s 116.07

HIST: 18 SR 580

ATTACHMENT P

Applicable Michigan Air Regulations

AIR POLLUTION CONTROL RULES

PART 3. EMISSION LIMITATIONS AND PROHIBITIONS--PARTICULATE MATTER

As Amended March 19, 2002

John Engler, Governor
Russell J. Harding, Director

Air Quality Division
Michigan Department of Environmental Quality

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MICHIGAN DEPARTMENT OF ENVIRONMENTAL QUALITY

AIR QUALITY DIVISION

As Amended March 19, 2002

PART 3. EMISSION LIMITATIONS AND PROHIBITIONS-- PARTICULATE MATTER

R 336.1301 Standards for density of emissions.

Rule 301. (1) Except as provided in subrules (2), (3), and (4) of this rule, a person shall not cause or permit to be discharged into the outer air from a process or process equipment a visible emission of a density greater than the most stringent of the following:

(a) A 6-minute average of 20% opacity, except for 1 6-minute average per hour of not more than 27% opacity.

(b) A limit specified by an applicable federal new source performance standard.

(c) A limit specified as a condition of a permit to install or permit to operate.

(2) The provisions of this rule shall not apply to any process or process equipment for which fugitive visible emission limitations are specified in any other administrative rule of the department.

(3) The provisions of subrule (1) of this rule shall not apply to visible emissions due to uncombined water vapor.

(4) Upon request by the owner of a process or process equipment for which an allowable particulate emission rate is established by R 336.1331, the department may establish an alternate opacity. Such alternate opacity shall not be established by the department unless the department is reasonably convinced of all of the following:

(a) That the process or process equipment subject to the alternate opacity is in compliance or on a legally enforceable schedule of compliance with the other rules of the department.

(b) That compliance with the provisions of subrule (1) of this rule is not technically or economically reasonable.

(c) That reasonable measures to reduce opacity have been implemented or will be implemented in accordance with a schedule approved by the department.

History: 1979 ACS 1, Eff. Jan. 19, 1980; 1985 MR 2, Eff. Feb. 22, 1985; 2002 MR 5, Eff. Mar. 19, 2002.

R 336.1331 Emission of particulate matter.

Rule 331. (1) It is unlawful for a person to cause or allow the emission of particulate matter from any process or process equipment in excess of any of the following limits:

(a) The maximum allowable emission rate listed in table 31.

(b) The maximum allowable emission rate listed by the department on its own initiative or by application. A new listed value shall be based upon the control results achievable with the application of the best technically feasible, practical equipment available. This applies only to processes and process equipment not assigned a specific emission limit in table 31.

(c) The maximum allowable emission rate specified as a condition of a permit to install or a permit to operate.

(d) The maximum allowable emission rate specified in a voluntary agreement, performance contract, stipulation, or an order of the department.

(e) The maximum allowable emission rate as determined by table 32 for processes and process equipment not covered in subdivisions (a) to (d) of this subrule.

(2) Compliance with any emission limit required by this rule shall be determined by using the corresponding reference test method specified in table 31 or the reference test method deemed appropriate by the department for processes or process equipment not listed in table 31.

(3) Tables 31, 32, 33, 34, and figure 31 read as follows:

History: 1979 ACS 1, Eff. Jan. 19, 1980; 1985 MR 2, Eff. Feb. 22, 1985; 1992 MR 9, Eff. Oct. 31, 1992; 2002 MR 5, Eff. Mar. 19, 2002.

TABLE 31
Particulate matter emission schedule

Process or process equipment	Capacity rating for each unit	Maximum allowable emission at operating conditions[1] (lbs. Particulate/1,000 lbs. gas except as noted)	Applicable reference test method
A. Fuel burning equipment			
1. Pulverized coal (includes cyclone furnaces)	0-1,000,000 lbs. steam per hour. Over 1,000,000 lbs. Steam per hour	See figure 31 for maximum emission limit. Apply to department for specific emission limit.	5B or 5C
2. Other modes of firing coal (other than pulverized)	0-100,000 lbs. steam per hour. 100,000-300,000 lbs.[2] steam per hour. Over 300,000 lbs. steam per hour.	0.65 until superseded by A.3 and A.4. 0.65 - 0.45 Apply to department for specific emission limit.	5B or 5C
3. Other modes of firing coal (other than pulverized) Existing fuel-burning equipment which is in a single structure and which has a combined coal-fired existing capacity less than 250,000,000 Btu per hour.	0-20,000,000 Btu per hour input. 20,000,001 to 100,000,000 Btu per hour input. Over 100,000,000 Btu per hour input	0.65 effective immediately. 0.45 compliance shall be achieved as expeditiously as practical, but not later than July 1, 1981. 0.30 compliance shall be achieved as expeditiously as practical, but not later than December 31, 1982.	5B or 5C 5B or 5C 5B or 5C
4. Other modes of firing coal (other than pulverized) Existing fuel-burning equipment which is in a single structure and which has a combined existing capacity equal to or greater than 250,000,000 Btu per hours.	All sizes	0.30 compliance shall be achieved as expeditiously as practical, but not later than December 31, 1982.	5B or 5C

Process or process equipment	Capacity rating for each unit	Maximum allowable emission at operating conditions[1] (lbs. particulate/1,000 lbs. gas except as noted)	Applicable reference test method
5. Other modes of firing coal (new processes or process equipment[6])	All sizes	0.10	5B or 5C
6. Wood (sawdust, shavings, hogged, other) where heat input of wood fuel greater than 75% of total heat input. All other combination fuel-burning equipment that uses wood as 1 of the fuels.		0.50 Apply to department for specific emission limit.	5B or 5C
7. Combination fuel-firing or combination fuel/waste-firing (new process or process equipment)	All sizes	Apply to department for specific emission limit.	5B or 5C
	Rating in pounds waste per hour		
B. Incinerators			
1. Residential apartments, commercial and industrial[3, 4]	0-100 Over 100	0.65 0.30	5B or 5C 5B or 5C
2. Municipal	All	0.30	5B or 5C
3. Pathological[4]		0.20	5B or 5C
4. Manure drying or incineration[4]		0.20	5B or 5C
5. Liquid waste incinerator		0.10 compliance shall be achieved as expeditiously as practical, but not later than December 31, 1982.	5B or 5C
6. Sewage sludge incinerator		0.20 compliance shall be achieved as expeditiously as practical, but not later than December 31, 1982.	5B or 5C

Process or process equipment	Capacity rating for each unit	Maximum allowable emission at operating conditions[1] (lbs. Particulate/1,000 lbs. gas except as noted)	Applicable reference test method
C. Steel manufacturing			
1. Basic oxygen furnaces A. Primary control equipment[12] B. Secondary control equipment[13] C. Primary control equipment if also used to control charging and tapping emissions		 0.057[11] 0.038[11] 0.057[11]	 5D 5D 5D
2. Electric furnaces A. Primary control equipment[14] B. Secondary control equipment[15] C. Primary control equipment if also used to control charging and tapping emissions		 0.057[11] 0.010[11] 0.010[11]	 5D 5D or 5E 5D or 5E
3. New sintering plants[6] A. Main windbox B. Discharge		 0.067[11] 0.038[11]	 5D or 5E 5D
4. Existing sintering plants A. Main windbox & discharge		 0.125[11]	 5D
5. Blast furnaces Blast furnace casthouse air cleaning device[17]		 0.02	 5D
6. Coke oven combustion stacks		0.095	5D
7. Coke oven push control equipment		0.10 lbs./ton of coke	5D
8. Coke oven quench towers		l,500[9] or 1,500[10]	See footnote 16 See footnote 16
9. Scarfing operations		0.057[11]	5D during scarfing operation

Process or process equipment	Total plant melt rate in tons/hour	Maximum allowable emission at operating conditions[1] (lbs. Particulate/1,000 lbs. gas except as noted)	Applicable reference test method
D. Ferrous cupola foundry operations[5]			
1. Existing production cupolas[7]	0-10 10-20 Over 20	0.40 0.25 0.15	5B or 5C 5B or 5C 5B or 5C
2. Existing jobbing cupolas[7]		0.40	5B or 5C
3. Electric arc melting		0.10	5B or 5C
4. Sand handling		0.10	5B or 5C
5. All new cupolas[6]	0-15 Over 15	1.8 - 0.7[2, 8] 0.7[8]	5B or 5C
E. Chemical and mineral kilns		0.20	5B or 5C
F. Asphalt paving plants			
1. Located within a priority I or II area (before January 1, 1980)		0.30	5B or 5C
2. Located within a priority I or II area (after January 1, 1980)		0.10	5B or 5C
3. Located outside priority I and II areas		0.30	5B or 5C
G. Cement manufacture			
1. Kiln - wet or dry process		0.25	5B or 5C
2. Clinker coolers (before January 1, 1981) (after January 1, 1981)		0.30 0.10	5B or 5C 5B or 5C
3. Grinding, crushing, and other material handling.		0.15	5B or 5C

Process or process equipment	Gas flow rate (SCFM)	Maximum allowable emission at operating conditions[1] (lbs. Particulate/1,000 lbs. gas except as noted)	Applicable reference test method
H. Iron ore pelletizing Grate kilns and traveling grates	Over 600,000 300,000-600,000 100,000-300,000 0-100,000	Apply to department for specific emission limit. 0.10 0.15 0.20	 5B or 5C 5B or 5C 5B or 5C
I. Fertilizer plants (including ammoniator, granulator, reactor, dryer, cooler blender and all other processes Compliance shall be achieved as expeditiously as practical, but not later than January 1, 1981.		0.10	5B or 5C
J. Exhaust systems serving material handling equipment not otherwise listed in table 31 Compliance shall be achieved as expeditiously as practical, but not later than July 1, 1981.		0.10	5B or 5C

Footnotes:

1. Fuel burning and incineration limitation shall be calculated to 50% excess air.
2. Emission limitations for specific ratings are determined by linear interpolation between the ranges shown.
3. These emission limitations do not apply to domestic incinerators (defined as having not more than 5 cubic feet of storage capacity.
4. Afterburner or approved equivalent is mandatory.
5. Differentiation between jobbing and production foundries.
   Cupolas used in a jobbing foundry are the same as those used in a production foundry and vary in size only according to the quantity of iron melted per hour.
   However, the cupolas in a jobbing foundry are run intermittently just long enough at one time to pour the molds that are ready on the foundry floor, job by job. This might be for a 2- to 4-hour period per day for any number of days per week.
   Production foundry cupolas melt continuously to pour a succession of molds that are constantly being prepared to reserve this continuous flow of iron. This could become 8 hours, 16 hours, or 24 hours per day for any number of days per week.
6. New processes or process equipment are defined as those for which the permit to install was issued after January 18, 1980.
7. Any existing cupolas are considered to be in compliance with table 31 of R 336.1331 if they meet the particulate emission limit for new cupolas.
8. Pounds of particulate per ton of charged material.
9. Milligrams per liter of total dissolved solids in the quench water.
10. Milligrams per liter of total dissolved solids in the make-up water.
11. Compliance shall be determined by means of a comparison between the emission limit and the measured emission rate calculated on a dry basis (pounds particulate per 1,000 pounds dry gas).
12. "Primary control equipment", as applied to basic oxygen furnaces, means the control equipment designed to capture and control particulate emissions during oxygen blowing.
13. "Secondary control equipment", as applied to basic oxygen furnaces, means the control equipment designed to capture and control particulate emissions during process steps other than oxygen blowing.
14. "Primary control equipment", as applied to electric furnaces, means the control equipment designed to capture and control particulate emissions during meltdown and refining.
15. "Secondary control equipment", as applied to electric furnaces, means the control equipment designed to capture and control particulate emissions during process steps other than meltdown and refining.

16. "Standard Methods for the Examination of Water and Wastewater" (14th edition) section 208C, as modified in R 336.2033, shall be used as the applicable test method.
17. The mass emission limit specified is not applicable where fume suppression technology, approved by the department, is used to control blast furnace casthouse emissions.

TABLE 32

Allowable rate of emission based on process weight rate[a]					
Process weight rate		Rate of Emission	Process weight rate		Rate of emission
Lb/hr	Tons/hr	Lb/hr	Lb/hr	Tons/hr	Lb/hr
100	0.05	0.55	16,000	8.0	16.5
200	0.10	0.88	18,000	9.0	17.9
400	0.20	1.40	20,000	10.0	19.2
600	0.30	1.83	30,000	15.0	25.2
800	0.40	2.22	40,000	20.0	30.5
1,000	0.50	2.58	50,000	25.0	35.4
1,500	0.75	3.38	60,000	30.0	40.0
2,000	1.00	4.10	70,000	35.0	41.3
2,500	1.25	4.76	80,000	40.0	42.5
3,000	1.50	5.38	90,000	45.0	43.6
3,500	1.75	5.95	100,000	50.0	44.6
4,000	2.00	6.52	120,000	60.0	46.3
5,000	2.50	7.58	140,000	70.0	47.8
6,000	3.00	8.56	160,000	80.0	49.0
7,000	3.50	9.49	200,000	100.0	51.2
8,000	4.00	10.40	1,000,000	500.0	69.0
9,000	4.50	11.20	2,000,000	1,000.0	77.6
10,000	5.00	12.00	6,000,000	3,000.0	92.7
12,000	6.00	13.60			

[a] Interpolation of the data in this table for process weight rates up to 60,000 lb/hr shall be accomplished by use of the equation $E = 4.10\ P^{0.67}$ and interpolation and extrapolation of the data for process weight rates in excess of 60,000 lb/hr shall be accomplished by use of the equation $E = 55.0\ P^{0.11} - 40$, where E = rate of emission in lb/hr and P = process weight in tons/hr.

Process weight -- The total amount of all material introduced into a process, including solid fuels, but excluding liquid fuels and gaseous fuels when these are used as fuels and air introduced for purposes of combustion.

Process weight rate -- For continuous or long-term operation: The total process weight for the entire period of operation or for a typical portion thereof, divided by the number of hours of such period or portion thereof. For batch operations: The total process weight for a period which covers a complete operation or an integral number of cycles, divided by the hours of actual process operation during such period.

TABLE 33

Priority I areas

County	Area
Calhoun	T2S, R4W, Section 34.
Genesee	Starting on Industrial Avenue, north to Stewart Avenue, east to Hitchcock Street, south to Olive Avenue (extended), south to Robert T. Longway Boulevard, west and southwest to Industrial Avenue.
Lapeer	T7N, R12E, that portion of Section 17 which lies south of M-21 and east of Fairground Road.
Monroe	Starting where Sandy Creek empties into Lake Erie, northwest to Maple Avenue (extended north-northeast), southwest to Elm Avenue, west to Herr Road, south to Dunbar Road and east to Plum Creek (which empties into Lake Erie).
Saginaw	Starting at Tittabawassee Road, east to I-75, east and south to Washington Avenue, west to 6th Street, north to Carrolton Street, northeast to Zilwaukee Street, north to Westervelt Street, north to Tittabawassee Road.
Wayne	Area included within the following (counter clockwise): Lake St. Clair to Moross Road to Seven Mile Road to VanDyke Road to Eight Mile Road to Wyoming Road to Seven Mile Road to Schaeffer Road to Fenkell Road to Greenfield Avenue to Joy Road to Southfield Expressway to Ford Road to Telegraph Road to Cherry Hill Road to Beech-Daly Road (extended) to Michigan Avenue to Inkster Road to Carlysle Street to Middle Belt Road to Vanborn Road to Wayne Road to Pennsylvania Road to Middle Belt Road to Sibley Road to Telegraph Road to King Road to Grange Road to Sibley Road to Jefferson Avenue to Bridge Street (Grosse Ile) extended to Detroit River.

TABLE 34

Priority II areas

County	Area
Bay	T14N, R5E, Sections 14 to16 and 21 to 23.
Delta	T39N, R22W, Sections 19, 30, south one-half of 17, and south one-half of 18.
Genesee	Starting on Industrial Avenue, north to Pierson Road, east to Dort Highway, south to Hitchcock Street, south to Olive Avenue (extended), south to Robert T. Longway Boulevard, west and southwest to Industrial Avenue.
Macomb	T4N, R14E, Sections 27, 28, 33, and 34.
Manistee	T21N, R16W, Sections 7,18, and 19; T21N, R17W, Sections 12 and 13.
Midland	T14N, R2E, Sections 14 to 16, 21 to 23, 26 to 28, and 33 to 35.
Monroe	T5S, RIOE, Sections 8, 9, and 15 to 17.
Muskegon	T9N, R16W, Sections 5 and 6; T1ON, R16W, Sections 21, 22, and 27 to 34.
Saginaw	Northeast section: starting on Tittabawassee Road, east to I-75, south to Wadsworth Avenue, west to I-675, west and north to Tittabawassee Road. Southwest section: T12N, R4E, the eastern half of Section 34 (that which is east of Maple Street) and Section 35.
St. Clair	T6N, R17E, Sections 2 to 4, 9 to 11, 14 to 16, 21, 22, and 28.

Wayne The area included within the following (counter clockwise): Lake St. Clair to Eight Mile Road to Schaeffer Road to McNichols Road to Greenfield Avenue to Schoolcraft Avenue to Evergreen Road to Joy Road to Telegraph Road to Ford Road to Beech-Daly Road to Cherry Hill Road to Inkster Road to Carlysle Street to Middle Belt Road to VanBorn Road to Wayne Road to Ecorse Road to Haggerty Highway to Tyler Road to Belleville Road to I-94 to Rawsonville Road to Oakville Waltz Road to Will Carleton Road to the Huron River to Lake Erie, except subarea listed in table 33.

R 336.1370 Collected air contaminants.

Rule 370. (1) Collected air contaminants shall be removed as necessary to maintain the equipment at the required operating efficiency. The collection and disposal of air contaminants shall be performed in a manner so as to minimize the introduction of contaminants to the outer air.

(2) At a minimum, in priority I and II areas listed in tables 33 and 34, the use of 1 or more of the following material handling methods is required for the transport of collected air contaminants:

(a) Enclosed trucking or transporting vehicles.

(b) Enclosed, pneumatic, or screw conveying transporting equipment.

(c) Water or dust suppressant sprays.

(d) An acceptable method which is equivalent to the methods listed in subdivisions (a), (b), and (c) of this subrule.

History: 1979 ACS 5, Eff. Feb. 18, 1981.

R 336.1371 Fugitive dust control programs other than areas listed in table 36.

Rule 37l. (l) Based on ambient air quality measurements or substantive complaints, the department may request that the person who is responsible for the operation of any facility which processes, uses, stores, transports, or conveys bulk materials, such as, but not limited to, coal, coke, metal ores, limestone, cement, sand, gravel, and material from air pollution control devices, or a facility which has activities specifically identified in R 336.l372 and which facility is in an area not listed in table 36, submit a fugitive dust control program. The department shall notify the person who is responsible for the operation of the facility of the provisions of R 336.l372 which apply to the facility and the reasons for the department's notification. Except as provided in subrule (3) of this rule, the control program shall be submitted to the department not later than 6 months after notification.

(2) A fugitive dust control program which is required by subrule (l) of this rule shall be in writing and shall provide for all of the following:

(a) Using l or more combinations of available technologies, operating practices, or methods listed in R 336.l372 as are reasonably necessary to control fugitive dust emissions.

(b) Consideration of the quantity, moisture content, specific gravity, and the particle size distribution of the bulk materials. The more friable, drier, lighter, and finer the bulk material is, the more effective the fugitive dust control methods incorporated into the control program shall be.

(c) The keeping and maintenance of records consistent with the various activities to be implemented under the control program.

(d) Identification of the control technologies, methods, or control equipment, if any, to be implemented or installed and the schedule, including increments of progress, for implementation or installation.

(3) Within 3 months following notification by the department that a fugitive dust control program is required, the person who is responsible for operating the facility has the opportunity to demonstrate, to the satisfaction of the department, that any part of the facility is not subject to the provisions of this rule.

(4) If a control program is not submitted within 6 months after notification by the department, then the department may proceed, pursuant to the act, toward the entry of a final order which contains a control program that meets the requirements of subrule (2) of this rule.

(5) The control program is subject to review and approval by the department. The department shall approve a control program only upon the entry of a legally enforceable order or as part of an approved permit to install or operate. If, in the opinion of the department, the program does not adequately meet the requirements set forth in subrule (2) of this rule, then the department may disapprove the program, state its reasons for disapproval, and require the preparation and submittal of an amended program within a specified time period. If, within the specified time period, an amended program is either not submitted or is submitted but, in the opinion of the department, fails to meet the requirements of subrule (2) of this rule, then the department may proceed, pursuant to the act, toward the entry of a final order which contains a control program that meets these requirements.

(6) After approval by the department, the person who is responsible for the preparation of the control program shall begin implementation of the program pursuant to the schedule contained in the control program.

(7) Either the person who is responsible for a facility or the department may request a revision to a department-approved control program to meet changing conditions. The department shall review the revision following the requirements of subrule (5) of this rule.

(8) Table 36 reads as follows:

TABLE 36

County	Area
Bay	T14N, R5E, Sections 14 to 16 and 21 to 23.
Calhoun	T2S, R4W, Section 34.
Delta	T39N, R22W, Sections 19, 30, south one-half of 17, and south one-half of 18.
Genesee	Starting on Industrial Avenue, north to Pierson Road, east to Dort Highway, south to Hitchcock Street, south to Olive Avenue (extended), south to Robert T. Longway Boulevard, west and southwest to Industrial Avenue.
Lapeer	T7N, R12E, that portion of Section 17 which lies south of M-21 and east of Fairground Road.
Macomb	T4N, R14E, Sections 27, 28, 33, and 34.
Manistee	T21N, R16W, Sections 7, 18, and 19; T21N, R17W, Sections 12 and 13.
Midland	T14N, R2E, Sections 14 to 16, 21 to 23, 26 to 28, and 33 to 35.
Monroe	Starting where Sandy Creek empties into Lake Erie, northwest to Maple Avenue (extended north-northeast), southwest to Elm Avenue, west to Herr Road, south to Dunbar Road and east to Plum Creek (which empties into Lake Erie).
Muskegon	T9N, R16W, Sections 5 and 6; T10N, R16W, Sections 21, 22, and 27 to 34.
Saginaw	Northeast section: starting on Tittabawassee Road, east to I-75, south to Wadsworth Avenue, west to I-675, west and north to Tittabawassee Road. Southwest section: T12N, R4E, the eastern half of Section 34 (that which is east of Maple Street) and Section 35.
St. Clair	T6N, R17E, Sections 2 to 4, 9 to 11, 14 to 16, 21, 22, and 28.
Wayne	Area included within the following (counter clockwise): Lake St. Clair to Moross Road to Seven Mile Road to Vandyke Road to Eight Mile Road to Wyoming Road to Seven Mile Road to Schaeffer Road to Fenkell Road to Greenfield Avenue to Joy Road to Southfield Expressway to Ford Road to Telegraph Road to Cherry Hill Road to Beech-Daly Road (extended) to Michigan Avenue to Inkster Road to Carlysle Street to Middle Belt Road to Vanborn Road to Wayne Road to Pennsylvania Road to Middle Belt Road to Sibley Road to Telegraph Road to King Road to Grange Road to Sibley Road to Jefferson Avenue to Bridge Street (Grosse Ile) extended to Detroit River. Also included is that portion of the City of Riverview which is south of Sibley Road and the City of Trenton.

History: 1979 ACS 5, Eff. Feb. 18, 1981; 1985 MR 4, Eff. Apr. 23, 1985; 2002 MR 5, Eff. Mar. 19, 2002.

R 336.1372 Fugitive dust control program; required activities; typical control methods.

Rule 372. (1) A fugitive dust control program which is required by R 336.1371 and which deals with 1 or more of the fugitive dust sources listed in this rule may include any of the typical control methods listed in this rule for that source.

(2) The following provisions apply to the loading or unloading of open storage piles of bulk materials as a source of fugitive dust:

(a) Open storage piles of bulk materials, hereinafter referred to as "piles", which meet any of the following 3 conditions need not be included in a fugitive dust control program:

(i) All piles of the same material at a manufacturing or commercial location which have a total volume of less than 100 cubic meters (131 yards^3).

(ii) Any piles at a manufacturing or commercial location if the total annual volumetric throughput of all the stored material at the site is less than 10,000 cubic meters (13,100 yards^3).

(iii) Any single pile at a manufacturing or commercial location that has a volume of less than 42 cubic meters (55 yards^3).

(b) Typical control methods for controlling fugitive emissions resulting from the loading or unloading of piles may include, but are not limited to, the following:

(i) Completely enclosing the pile within a building furnished with department-approved air pollution control equipment.

(ii) Using pneumatic conveying or telescopic chutes.

(iii) Spraying the working surface of the pile with water or dust-suppressant compound.

(iv) Directing engine exhaust gases that are generated by the machine used on the piles for loading or unloading upwards.

(v) Minimizing the drop distance from which the material is discharged into the pile. The drop distance shall be specified in the control program.

(vi) Periodic removal of spilled material in areas within 100 meters (328 feet) from the pile. The frequency of removal shall be specified in the control program.

(3) All of the following provisions apply to the transporting of bulk materials as a source of fugitive dust:

(a) Trucks which have less than a 2-ton capacity that are used to transport sand, gravel, stones, peat, and topsoil are exempt from the provisions of this subrule.

(b) Typical control methods for controlling fugitive emissions resulting from the transporting of bulk materials by truck may include, but are not limited to, the following:

(i) Completely covering open-bodied trucks.

(ii) Cleaning the wheels and the body of each truck to remove spilled materials after the truck has been loaded.

(iii) Use of completely enclosed trucks.

(iv) Tarping the truck when operating empty if residue has not been completely removed after emptying.

(v) Cleaning the residue from the inside of the truck after emptying.

(vi) Loading trucks so that no part of the load making contact with any sideboard, side panel, or rear part of the load enclosure comes within 6 inches of the top part of the enclosure.

(vii) Maintaining tight truck bodies so that leakages within the body will be eliminated and future leakages prevented.

(viii) Spraying the material being transported in a vehicle with a dust suppressant. The frequency of spraying shall be specified in the control program.

(ix) Restricting the speed of the vehicle which transports the material. The speed of the vehicle shall be specified in the control program.

(4) The following provision applies to outdoor conveying as a source of fugitive dust: Typical control methods for controlling fugitive emissions resulting from conveying bulk materials may include, but are not limited to, the following:

(a) Completely enclosing all conveyor belts and equipping them with belt wipers and hoppers of proper size to prevent excessive spills.

(b) Enclosing transfer points and, if necessary, exhausting them to a baghouse or similar control device at all times when the conveyors are in operation.

(c) Equipping the conveyor belt with not less than 210-degree enclosures.

(d) Restricting the speed of conveyor belts. The belt speed shall be specified in the control program.

(e) Periodically cleaning the conveyor belt to remove the residual material. The frequency of cleaning shall be specified in the control program.

(f) Minimizing the distance between transfer points. The distance between transfer points shall be specified in the control program.

(g) Removing the spilled material from the ground under conveyors. The frequency of removal shall be specified in the control program.

(5) The following provisions apply to roads and lots as sources of fugitive dust:

(a) Roads and lots which are located within industrial, commercial, and government-owned facilities and which meet the following 2 conditions are not subject to the requirement of submitting a fugitive dust control program:

(i) The traffic volume is less than 10 vehicles per day on a monthly average.

(ii) The lots are less than 500 square meters (5,382 feet^2) in area.

(b) Typical control methods for controlling fugitive emissions resulting from roads and lots located within industrial, commercial, and government-owned facilities may include, but are not limited to, the following:

(i) Paving roads and parking lots with a hard material, such as concrete, asphalt, or an equivalent which is approved by the department.

(ii) Mechanically cleaning paved surfaces by vacuum sweeping, wet sweeping, or flushing. The frequency of cleaning shall be specified in the control program.

(iii) Washing the wheels of every truck leaving the plant premises.

(iv) Treating the roads and lots with oil or a dust-suppressant compound which is approved by the department. The frequency of application shall be specified in the control program.

(v) Periodically maintaining off-road surfaces with gravel where trucks have frequent access. The frequency of maintenance shall be specified in the control program.

(6) The following provisions apply to inactive storage piles as sources of fugitive dust:

(a) Inactive storage piles that are less than or equal to 500 cubic meters (654 $yards^3$) in volume are not subject to the requirement of submitting a fugitive dust control program.

(b) Typical control methods for controlling fugitive emissions resulting from inactive storage piles may include, but are not limited to, the following:

(i) Completely covering the pile with tarpaulin or other material approved by the department.

(ii) Completely enclosing the pile within a building.

(iii) Enclosing the pile with not less than 3 walls so that no portion of the stored material is higher than the walls.

(iv) Periodically spraying the piles with water or other dust-suppressant compound approved by the department. The frequency of application shall be specified in the control program.

(v) Growing vegetation on and around the pile.

(7) The following provisions apply to building ventilation as a source of fugitive dust:

(a) This subrule is applicable to all of the following:

(i) Ferrous and nonferrous foundries.

(ii) Electric arc furnaces, blast furnace casthouses, sinter plants, and basic oxygen processes at iron and steel production facilities.

(iii) Metal heat treating.

(iv) Metal forging.

(v) Bulk material handling, storage, drying, screening, and crushing.

(vi) Metal fabricating and welding.

(vii) Briquetting, sintering, and pelletizing operations.

(viii) Machining and pressing of metal.

(ix) Stone, clay, and glass production.

(x) Lime, cement, and gypsum production.

(xi) Chemical and allied product production.

(xii) Asphalt and concrete mixing operations.

(b) Typical control methods for controlling fugitive emissions resulting from building openings, such as roof monitors, powered and unpowered ventilators, doors, windows, and holes in the building structure integrity, may include, but are not limited to, the following:

(i) Exhausting the entire building to a dust collection system which is acceptable to the department.

(ii) Using local hoods connected to a dust collection system to capture emissions within the building.

(iii) Establishing and maintaining operating procedures and internal housekeeping practices (specify details).

(iv) Installing removable filter media across the vent openings.

(8) The following provisions apply to fugitive dust emissions from construction, renovation, or demolition activities located in priority I areas:

(a) This subrule is applicable to the owner or prime contractor, except for those owners or prime contractors who construct, renovate, or demolish less than 12 single-family dwelling units per year.

(b) Typical control methods for controlling fugitive dust emissions from construction, renovation, or demolition activities may include, but are not limited to, the following:

(i) Spraying of all work areas with water or other dust-suppressant compound which is approved by the department.

(ii) Completely covering the debris, excavated earth, or other airborne materials with tarpaulin or any other material which is approved by the department.

(iii) Any other method acceptable to the department.

History: 1979 ACS 5, Eff. Feb. 18, 1981; 2002 MR 5, Eff. Mar. 19, 2002.

AIR POLLUTION CONTROL RULES

PART 4. EMISSION LIMITATIONS AND PROHIBITIONS - SULFUR-BEARING COMPOUNDS

As Amended March 19, 2002

John Engler, Governor
Russell J. Harding, Director

Air Quality Division
Michigan Department of Environmental Quality

INTERNET: http://www.michigan.gov

PART 4. EMISSION LIMITATIONS AND PROHIBITIONS - SULFUR-BEARING COMPOUNDS

R 336.1402 Emission of sulfur dioxide from fuel-burning sources other than power plants.

Rule 402. (1) Except as provided in rule 401 and subrule (2), after January 1, 1981, it is unlawful for a person to cause or allow the emission of sulfur dioxide from the combustion of any coal or oil fuel in excess of 1.7 pounds per million Btu's of heat input for oil fuel or in excess of 2.4 pounds per million Btu's of heat input for coal fuel.

(2) The provisions of this rule do not apply to a fuel-burning source that is unable to comply with the specified emission limits because of sulfur dioxide emissions caused by the presence of sulfur in other raw materials charged to the fuel-burning source. This exception shall apply if at any time the actual sulfur dioxide emission rate exceeds the expected theoretical sulfur dioxide emission rate from fuel burning. The expected theoretical sulfur dioxide emission rate shall be based on the quantity of fuel burned and the average sulfur content of the fuel.

History: 1979 ACS 1, Eff. Jan. 19, 1980.

AIR POLLUTION CONTROL RULES

PART 7. EMISSION LIMITATIONS AND PROHIBITIONS--NEW SOURCES OF VOLATILE ORGANIC COMPOUND EMISSIONS

As Amended March 19, 2002

John Engler, Governor
Russell J. Harding, Director

Air Quality Division
Michigan Department of Environmental Quality

INTERNET: http://michigan.gov

MICHIGAN DEPARTMENT OF ENVIRONMENTAL QUALITY

AIR QUALITY DIVISION

As Amended March 19, 2002

PART 7. EMISSION LIMITATIONS AND PROHIBITIONS-- NEW SOURCES OF VOLATILE ORGANIC COMPOUND EMISSIONS

R 336.1702 New sources of volatile organic compound emissions generally.

Rule 702. A person who is responsible for any new source of volatile organic compound emissions shall not cause or allow the emission of volatile organic compound emissions from the new source in excess of the lowest maximum allowable emission rate of the following:

(a) The maximum allowable emission rate listed by the department on its own initiative or based upon the application of the best available control technology.

(b) The maximum allowable emission rate specified by a new source performance standard promulgated by the United States environmental protection agency under authority enacted by title I, part A, section 111 of the clean air act, as amended, 42 U.S.C. §7413.

(c) The maximum allowable emission rate specified as a condition of a permit to install or a permit to operate.

(d) The maximum allowable emission rate specified in part 6 of these rules which would otherwise be applicable to the new source except for the date that the process or process equipment was placed into operation or for which an application for a permit to install, under the provisions of part 2 of these rules, was made to the department. If the part 6 allowable emission rate provides for a future compliance date, then the future compliance date shall also be applicable to a new source pursuant to this subdivision.

History: 1979 ACS 1, Eff. Jan. 19, 1980; 1993 MR 4, Eff. Apr. 28, 1993; 2002 MR 5, Eff. Mar. 19, 2002.

AIR POLLUTION CONTROL RULES

PART 8. EMISSION LIMITATIONS AND PROHIBITIONS—OXIDES OF NITROGEN

As Amended December 4, 2002

Jennifer M. Granholm, Governor
Steven E. Chester, Director

Air Quality Division
Michigan Department of Environmental Quality

INTERNET: http://www.michigan.gov

MICHIGAN DEPARTMENT OF ENVIRONMENTAL QUALITY

AIR QUALITY DIVISION

As Amended December 4, 2002

PART 8. EMISSION LIMITATIONS AND PROHIBITIONS— OXIDES OF NITROGEN

R 336.1801 Emission of oxides of nitrogen from non-sip call stationary sources.

Rule 801. (1) As used in this rule:

(a) "Capacity factor" means either of the following:

(i) The ratio of a unit's actual annual electric output, expressed in megawatt hour, to the unit's nameplate capacity times 8,760 hours.

(ii) The ratio of a unit's annual heat input, expressed in million British thermal units or equivalent units of measure, to the unit's maximum design heat input, expressed in million British thermal units per hour or equivalent units of measure, times 8,760 hours.

(b) “Fossil fuel-fired” means the combustion of fossil fuel, alone or in combination with any other fuel, where the fossil fuel actually combusted comprises more than 50% of the fuel mass or annual heat input on a British thermal unit basis. Coke oven gas is a fossil fuel.

(c) "Low-NO_x burners" means 1 of several developing combustion technologies used to minimize the formation of emissions of nitrogen oxides. As applicable to cement kilns, low-NO_x burners means a type of cement kiln burner system designed to minimize NO_x formation by controlling flame turbulence, delaying fuel/air mixing, and establishing fuel-rich zones for initial combusting, that for firing of solid fuel in the burning end zone of a kiln's main burner includes an indirect firing system or comparable technique for the main burner in the burning end zone of the kiln to minimize the amount of primary air supplied through the burner. In an indirect firing system, 1 air stream is used to convey pulverized fuel from the grinding equipment and at least 1 or more other air streams are used to supply primary air to the burning end zone kiln burner of the kiln with the pulverized fuel, with intermediate storage of the fuel, and necessary safety and explosion prevention systems associated with the intermediate storage of fuel.

(d) "Mid-kiln system firing" means the secondary firing in a kiln system by injecting solid fuel at an intermediate point in the kiln system using a specially designed heat injection mechanism for the purpose of decreasing NO_x emissions through coal burning part of the fuel at lower temperatures and reducing conditions at the fuel injection point that may destroy some of the NO_x.

(e) “Non-sip call source” means any stationary source of oxides of nitrogen emissions that is not defined as an oxide of nitrogen budget source in R 336.1803.

(f) “Ozone control period” means the period of May 31, 2004, through September 30, 2004, and the period of May 1 through September 30 each subsequent and prior year.

(g) "Peaking unit" means a unit that has an average capacity factor of not more than 10% during the previous 3 calendar years and a capacity factor of not more than 20% in each of those calendar years.

(h) “Process heater” means any combustion equipment which is fired by a liquid fuel or a gaseous fuel, or both, and which is used to transfer heat from the combustion gases to a process fluid, superheated steam, or water.

(i) “Unit” means a fossil fuel-fired combustion device.

(j) “Utility system” means all interconnected units and generators which are subject to subrule (2) of this rule and which are operated by the same utility operating company or by common ownership and control.

(2) An owner or operator of a fossil fuel-fired, electricity-generating utility unit which has the potential to emit more than 25 tons each ozone control period of oxides of nitrogen and which serves a generator that has a nameplate capacity of 25 megawatts or more shall comply with the emission limits during the ozone control period as follows:

(a) By May 31, 2004, meet the least stringent of a utility system-wide average oxides of nitrogen emission rate of 0.25 pounds per million British thermal units heat input or an emission rate based on a 65% reduction of oxides of nitrogen from 1990 levels.

(b) The date listed in subdivision (a) of this subrule may be extended by up to 2 years if an owner or operator makes an acceptable demonstration to the department that the additional time is necessary to avoid disruption of the energy supply in the state or if the additional time is necessary to comply with the provisions of this rule.

(3) An owner or operator shall demonstrate compliance with the emission limits in subrule (2) of this rule as follows:

(a) To demonstrate compliance with a utility system-wide average emission rate, the owner or operator shall show that the sum of the mass emissions from all units owned or operated by a utility that is subject to subrule (2) of this rule which occurred during the ozone control period, divided by the sum of the heat input from all units owned or operated by a utility that is subject to subrule (2) of this rule which occurred during the ozone control period is less than or equal to the limits in subrule (2) of this rule.

(b) To demonstrate compliance with the percent reduction requirements of subrule (2) of this rule, the owner or operator shall provide calculations showing that the utility system average emission rate during each compliance ozone control period has been reduced below the 1990 ozone control period average emission rate by the applicable percent reduction listed in subrule (2) of this rule. The 1990 ozone control period average emission rate is the sum of the mass emissions from all units owned or operated by a utility that is subject to subrule (2) of this rule which occurred during the 1990 ozone control period divided by the sum of the heat input from all units owned or operated by a utility that is subject to subrule (2) of this rule which occurred during the 1990 ozone control period.

(4) By May 31, 2004, an owner or operator of a fossil fuel-fired emission unit which has the potential to emit more than 25 tons of oxides of nitrogen each ozone control period, except for an emission unit that is subject to subrule (2) of this rule, and which has a maximum rated heat input capacity of more than 250 million British thermal units per hour shall comply with the following provisions, as applicable:

(a) An owner or operator of a fossil fuel-fired, electricity-generating utility unit which serves a generator that has a nameplate capacity of less than 25 megawatts which has a maximum rated heat input capacity of more than 250 million British thermal units per hour shall comply with the appropriate oxides of nitrogen emission limit in table 81 of this rule.

(b) An owner or operator of a fossil fuel-fired boiler or process heater shall meet the emission limits contained in table 81 of this rule.

(c) An owner or operator of a gas-fired boiler or process heater that fires gaseous fuel which contains more than 50% hydrogen by volume shall comply with an oxide of nitrogen emission limit of 0.25 pounds per million Btu heat input.

(d) An owner or operator of a stationary internal combustion engine which is subject to the provisions of this rule and which has a maximum rated heat input capacity that is the heat input at 80 degrees Fahrenheit at sea level and takes into account inlet and exhaust losses shall comply with the following oxides of nitrogen emission limits, as applicable:

(i) For a natural gas-fired stationary internal combustion engine - 14 grams of oxides of nitrogen per brake horsepower hour at rated output.

(ii) For a diesel-fired stationary internal combustion engine - 10 grams of oxides of nitrogen per brake horsepower hour at rated output.

(e) An owner or operator of a cement kiln that is subject to the provisions of this rule shall reduce kiln oxides of nitrogen emissions by any of the following methods:

(i) Low oxides of nitrogen burners.

(ii) Mid-kiln system firing.

(iii) A 25% rate-based reduction of oxides of nitrogen from 1995 levels. Compliance with this paragraph shall be based on calculations showing that the emission rate, on a pounds of oxides of nitrogen per ton of clinker produced basis, during each compliance ozone control period, has been reduced below the 1995 ozone control period emission rate by 25%.

(f) An owner or operator of a stationary gas turbine which is subject to the provisions of this rule and which has a maximum rated heat input capacity that is the heat input at 80 degrees Fahrenheit at sea level and takes into account inlet and exhaust losses shall comply with an emission limit of 75 parts per million, dry volume, corrected to 15% oxygen, at rated capacity. The provisions of this rule do not apply to a stationary gas turbine that is subject to a new source performance standard contained in 40 C.F.R. part 60, subpart gg (2001), which is adopted by reference in subrule (7) of this rule.

(g) An owner or operator of an emission unit which is subject to this rule and which is not otherwise subject to the provisions of subdivisions (a) to (f) of this subrule shall submit a proposal for oxides of nitrogen control by November 17, 2000. An owner or operator shall implement the control program by May 31, 2004, or by an alternate date approved by the department. The owner or operator shall obtain department approval of the proposed control program. The proposal for oxides of nitrogen control shall include all of the following information:

(i) A listing of reasonably available oxides of nitrogen control technologies, including the costs of installation and operation, cost of control per ton of oxides of nitrogen reduced, and the projected effectiveness of the proposed control technologies. The owner or operator shall use costing methodologies acceptable to the department.

(ii) The technology selected for controlling oxides of nitrogen emissions from the emission unit, considering technological and economic feasibility.

(iii) A proposal for testing, monitoring, and reporting oxides of nitrogen emissions.

(h) The compliance date listed in this subrule may be extended by up to 2 years if an owner or operator makes an acceptable demonstration to the department that the additional time is necessary to comply with the provisions of this rule. The owner or operator of a unit subject to subrules (2) and 4(a) to (f) of this rule may request an alternate emission limit or control requirement if there is an acceptable demonstration made to the department that compliance with the limits in table 81, or other limits or control requirements, is not reasonable. The request for an alternate emission limit or control requirement shall be submitted to the department within 60 days of the effective date of this amendatory rule and shall include all of the information listed in subdivision (g)(i) to (iii) of this subrule.

(5) The method for determining compliance with the emission limits in subrule (4) of this rule is as follows:

(a) If the emission limit is in the form of pounds of oxides of nitrogen per million British thermal unit, then the unit is in compliance if the sum of the mass emissions from the unit that occurred during the ozone control period, divided by the sum of the heat input from the unit that occurred during the ozone control period, is less than or equal to the limit in subrule (4) of this rule.

(b) For an emission unit not subject to subdivision (a) of this subrule, the method for determining compliance shall be a method acceptable to the department.

(6) An owner or operator of a source of oxides of nitrogen that is subject to the provisions of this rule may participate in Michigan's emission trading program, being R 336. 2201 to R 336.2218.

(7) The owner or operator of an emission unit subject to subrule (2) of this rule shall measure oxides of nitrogen emissions with a continuous emission monitoring system; an alternate method as described in 40 C.F.R. part 60 or 75 and acceptable to the department; or a method currently in use and acceptable to the department, including methods contained in existing permit conditions. The provisions of 40 C.F.R. parts 60 and 75 (2001) are adopted by reference in these rules. Copies of the regulations may be inspected at the Lansing office

of the air quality division of the department of environmental quality. Copies of the regulations may be obtained from the Department of Environmental Quality, Air Quality Division, 525 West Allegan Street, P.O. Box 30260, Lansing, Michigan 48909-7760, or from the Superintendent of Documents, Government Printing Office, P.O. Box 371954, Pittsburgh, Pennsylvania 15250-7954, at a cost at the time of adoption of these rules of $53.00 for part 60 and $55.00 for part 75; or on the United States government printing office internet web site at www.access.gpo.gov.

(8) The owner or operator of a boiler, process heater, stationary internal combustion engine, stationary gas turbine, cement kiln, or any other stationary emission unit that is subject to the provisions of subrule (4) of this rule shall measure oxides of nitrogen emissions by any of the following:

(a) Performance tests described in subrule (9) of this rule.

(b) Through the use of a continuous emission monitor in accordance with the provisions of subrule (11) of this rule.

(c) According to a schedule and using a method acceptable to the department.

(9) An owner or operator of an emission unit that measures oxides of nitrogen emissions by performance tests as specified in subrule (8) of this rule shall do all of the following:

(a) Conduct an initial performance test not later than 90 days after the compliance deadline. For an emission unit that is not in service on or after the compliance deadline, the owner or operator shall contact the department and schedule an alternate initial performance test as agreed to by the department.

(b) After the initial performance test, conduct a compliance performance test each ozone control period or according to the following schedule:

(i) After 2 consecutive ozone control periods in which the emission unit demonstrates compliance, an owner or operator shall conduct performance tests at least once every 2 years during the ozone control period.

(ii) After a total of 4 consecutive ozone control periods in which the emission unit has remained in compliance, an owner or operator shall conduct performance tests at least once every 5 years during the ozone control period.

(c) If an emission unit is not in compliance at the end of an ozone control period, then the owner or operator shall conduct a compliance performance test each ozone control period, but can again elect to use the alternative schedule specified in subdivision (b) of this subrule.

(d) An owner or operator shall submit 2 copies of each compliance performance test to the department within 60 days of completion of the testing. The test results shall be presented and include data as requested in the department format for submittal of source emission test plans and reports. All performance test reports shall be kept on file at the plant and made available to the department upon request.

(10) An owner or operator of an emission unit who is required to conduct performance testing under subrule (8) of this rule shall submit a test plan to the department, not less than 30 days before the scheduled test date. To ensure proper testing, the plan shall supply the

information in the department format for submittal of source emission test plans and reports. The owner or operator shall give the department a reasonable opportunity to witness the tests.

(11) An owner or operator of an emission unit that measures oxides of nitrogen emissions by a continuous emission monitoring system or an alternate method, as specified in subrule (7) or (8) of this rule, shall do either of the following:

(a) Use procedures set forth in 40 C.F.R., part 60, subpart A and appendix B, and comply with the quality assurance procedures in appendix F, or 40 C.F.R., part 75, and associated appendices, as applicable and acceptable to the department. Title 40 C.F.R., parts 60 and 75, are adopted by reference in subrule (7) of this rule.

(b) An owner or operator of an emission unit who uses a continuous emission monitoring system to demonstrate compliance with this rule and who has already installed a continuous emission monitoring system for oxides of nitrogen pursuant to other applicable federal, state, or local rules shall meet the installation, testing, operation, calibration, and reporting requirements specified by federal, state, or local rules.

(12) The owner or operator of an emission unit that is subject to this rule shall submit a summary report, in an acceptable format, to the department within 60 days after the end of each ozone control period. The report shall include all of the following information:

(a) The date, time, magnitude of emissions, and emission rates where applicable, of the specified emission unit or utility system.

(b) If emissions or emission rates exceed the emissions or rates allowed for in the ozone control period by the applicable emission limit, the cause, if known, and any corrective action taken.

(c) The total operating time of the emission unit during the ozone control period.

(d) For continuous emission monitoring systems, system performance information shall include the date and time of each period during which the continuous monitoring system was inoperative, except for zero and span checks, and the nature of the system repairs or adjustments. When the continuous monitoring system has not been inoperative, repaired, or adjusted, the information shall be stated in the report.

(13) Table 81 reads as follows:

Table 81

Boilers and process heaters with heat input capacity of 250 million Btu or more oxides of nitrogen (NO_x) emission limitations (pounds NO_x per million Btu of heat input averaged over the ozone control period)	
Fuel type	Emission limit
Natural gas	0.20
Distillate oil	0.30
Residual oil	0.40
Coal (1) Coal spreader stoker (2) Pulverized coal fired	 0.40 0.40
Gas (other than natural gas)[1]	0.25

For units operating with a combination of gas, oil, or coal, a variable emission limit calculated as the heat input weighted average of the applicable emission limits shall be used. The emission limit shall be determined as follows:

Emission limit = a(0.20) + b(applicable oil limit) + c(applicable coal limit) + d(0.25)

Where:
a = Is the percentage of total heat input from natural gas
b = Is the percentage of total heat input from oil
c = Is the percentage of total heat input from coal
d = Is the percentage of total heat input from gas (other than natural gas)

[1]This may include a mixture of gases. In this case, natural gas may be part of the mixture.

(14) The provisions of this rule do not apply to the following emission unit or units:

(a) A unit that is subject to oxides of nitrogen standards, which have been promulgated in a federal implementation plan under section 110(c) of the clean air act, required under section 126 of the clean air act, or promulgated in a federal regulation under 40 C.F.R. part 51 or part 60 and which are equally stringent or more stringent than this rule.

(b) A unit that is subject to any other rule included in this part.

(c) A peaking unit. The owner or operator shall retain records of capacity for a period of 5 years demonstrating that the unit meets the definition of a peaking unit. The unit shall become subject to the provisions of this rule on January 1 of the year following failure to meet the peaking unit definition.

History: 2000 MR 7, Eff. May 17, 2000; .2002 MR 22, Eff. December 4, 2002.

ATTACHMENT Q

Applicable Canadian Provincial Air Regulations

CONSOLIDATED NEWFOUNDLAND REGULATION 957/96
Air Pollution Control Regulations
under the
Environment Act
(O.C. 96-246)

Under the authority of section 14 of the *Environment Act* and the *Subordinate Legislation Revision and Consolidation Act*, the Lieutenant-Governor in Council makes the following regulations.

REGULATIONS

Stationary source of air contamination
5. (1) Subject to section 4, the standards for concentrations of air contaminants from a stationary source at a point of impingement shall be those as prescribed in Schedule B.
(2) The amount of air contaminants in the atmosphere at the point of impingement measured or calculated in accordance with a method approved by the minister shall not exceed the amounts established in Schedule B.
(3) For the purpose of enforcing these regulations a contaminant at a point of impingement shall be calculated in accordance with a method approved by the minister.
(4) A person shall not operate or cause to be operated a stationary source in a manner that does not comply with the standards prescribed in Schedule B.

26/81 s7

Visible emissions
7. A visible emission chart shall be used by the department to determine the opacity of a visible emission.

26/81 s8

Visible emission standards
8. (1) A person shall not cause or permit to be caused a visible emission having an opacity greater than density No. 1 on the visible emission chart referred to in section 7.
(2) Notwithstanding subsection (1), for a period of not more than 4 minutes in the aggregate in a half hour period, visible emission may have an opacity exceeding density No. 1 but not exceeding density No. 2 on the visible emission chart.
(3) Notwithstanding subsection (1), where a new fire is started in combustion process equipment, the visible emission may have an opacity not exceeding density No. 3 on the visible emission chart for a period not more than 3 minutes in the aggregate in a quarter hour period up to one hour after the new fire is started.

26/81 s9

Recording devices
12. (1) The minister may require the installation of devices or methods that are necessary to record the periods of operation of process, combustion or control equipment, the records from which shall be available to a department official.
(2) The minister may require the installation of such monitoring and recording devices as are necessary to measure and record concentrations of air contaminants at their source and points of impingement, the records and measurements from which shall be available to a department official.

26/81 s13

Schedule B

Standards for Emitted Contaminants

Item	*Col. 1*	*Col. 2*	*Col. 3*
	Name of Contaminant	*Unit of Concentration (1)*	*Concentration at Point of Impingement – 1 hour average*
1.	Acetic Acid		2100
2.	Acetylene		46000
3.	Acetone		40000
4.	Acrylamide		37
5.	Ammonia		3000
6.	Antimony	Total micrograms of antimony in free and combined form per cubic metre of air.	62
7.	Arsine		8
8.	Beryllium	Total micrograms of beryllium in free and	0.02

		combined form per cubic metre of air.	
9.	Boron Tribromide		80
10.	Boron Trichloride		80
11.	Boron Trifluoride		4
12.	Boron	Total micrograms of boron in free and combined form per cubic metre of air.	80
13.	Bromine		60
14.	Cadmium	Total micrograms of cadmium in free and combined form per cubic metre of air.	4
15.	Calcium hydroxide		22
16.	Calcium Oxide		16
17.	Carbon Black		21
18.	Carbon Disulphide		270
19.	Carbon Monoxide		5000
20.	Chlorine		250
21.	Chlorine Dioxide		70
22.	Copper	Total micrograms of copper in free and combined form per cubic metre of air.	80
23.	Cresols		190
24.	Decaborane		40
25.	Diborane		16
26.	Dicapryl Phthalate		80
27.	Dimethyl Disulphide		33
28.	Dimethyl Sulphide		25
29.	Dioctyl Phthalate		80
30.	Dustfall	Micrograms per square metre.	7000
31.	Ethyl Acetate		16000
32.	Ethyl Acrylate		3.7
33.	Ethyl Benzene		3300
34.	Ferric Oxide		62
35.	Fluorides, (Gaseous) (April 15 to October 15)	Micrograms of gaseous, inorganic fluoride per cubic metre of air expressed as hydrogen fluoride.	4
36.	Fluorides, (Total) (April 15 to October 15)	Total micrograms of inorganic fluoride per cubic metre of air expressed as hydrogen fluoride.	7
37.	Fluorides, (Total) (October 16 to April 14)	Total micrograms of inorganic fluoride per cubic metre of air expressed as hydrogen fluoride.	14
38.	Formaldehyde		54
39.	Formic Acid		1200

40.	Furfural		800
41.	Furfuryl Alcohol		2500
42.	Hydrogen Chloride		80
43.	Hydrogen Cyanide		950
44.	Hydrogen sulphide		25
45.	Iron (metallic)		8
46.	Lead	Total micrograms of lead in free or combined form per cubic metre of air.	8
47.	Lithium Hydrides	Total micrograms of lithium hydrides per cubic metre of air.	6.2
48.	Lithium	Total micrograms of lithium in other than hydride compounds per cubic metre of air.	50
49.	Magnesium Oxide	Total micrograms of magnesium oxide per cubic metre of air.	80
50.	Mercaptans	Total micrograms of mercaptans per cubic metre of air expressed as methyl mercaptans.	16
51.	Mercury (alkyl)	Total micrograms of alkyl mercury compounds per cubic metre of air.	1.2
52.	Mercury	Total micrograms of mercury in free and combined form per cubic metre of air.	4
53.	Methyl Acylate		3.3
54.	Methyl Alcohol		69000
55.	Methyl Chloroform (1,1,1-Trichloroethane)		288000
56.	Methyl Ethyl Ketone (2-Butanone)		26000
57.	Methyl Methacrylate		710
58.	Milk Powder		16
59.	Monomethyl Amine		21
60.	Nickel	Total micrograms of nickel in free and combined form per cubic metre of air.	4
61.	Nickel Carbonyl		1.2
62.	Nitic Acid		80
63.	Nitrilotriacetic Acid		80
64.	Nitrogen Oxides	Micrograms of nitrogen oxides per cubic metre of air expressed as NO2	400
65.	Ozone		160
66.	Pentaborane		2.5
67.	Phenol		80
68.	Phosgene		110
69.	Phosphoric Acids	Micrograms of phosphoric acids per cubic metre of air expressed as P2O5.	80

70.	Phthalic Anhydride		80
71.	Propylene Dichloride		2000
72.	Silver	Total micrograms of silver in free and combined form per cubic metre of air.	2.5
73.	Styrene		330
74.	Sulphur Dioxide		680
75.	Sulphuric Acid		80
76.	Suspended Particulate Matter (particulates less than 44 microns in size)	Total micrograms of suspended particulate matter per cubic metre of air.	80
77.	Tellurium (except hydrogen telluride)		25
78.	Tetrahydrofuran		77000
79.	Tin	Total micrograms of tin in free and combined form per cubic metre of air.	25
80.	Titanium	Total micrograms of titanium in free and combined form per cubic metre of air.	80
81.	Toluene		1600
82.	Toluene Di-isocyanate		0.8
83.	Trichloroethylene		70000
84.	Vanadium	Total micrograms of vanadium in free and combined form per cubic metre of air.	4.1
85.	Xylenes		1900
86.	Zinc	Total micrograms of zinc in free and combined form per cubic metre of air.	80

(1) Unit of concentration is micrograms of the contaminant in Column 1, per cubic metre of air, unless otherwise noted.

26/81 Sch 1; 279/82 s5

Earl G. Tucker, Queen's Printer
(This document contains the reprints of original due to errors of July 18, 1997, p.811 and August 8, 1997, p.917.)

Environmental Protection Act
Loi sur la protection de l'environnement
R.R.O. 1990, REGULATION 346
Amended to O. Reg. 342/01
GENERAL - AIR POLLUTION

Notice of Currency:* This document is up to date.
*This notice is usually current to within two business days of accessing this document. For more current amendment information, see the Table of Regulations (Legislative History).

This Regulation is made in English only.

Control of Air Contaminants

5. (1) The maximum concentration of a contaminant set out in Column 1 of Schedule 1 at a point of impingement from a source of contaminant, other than a motor vehicle, shall not be greater than the concentration set out opposite thereto in Column 3 of Schedule 1, expressed in the unit of concentration set out opposite thereto in Column 2 of Schedule 1. R.R.O. 1990, Reg. 346, s. 5 (1).

(2) The concentration of a contaminant at a point of impingement may be calculated in accordance with the Appendix. R.R.O. 1990, Reg. 346, s. 5 (2).

(3) No person shall cause or permit the concentration of a contaminant at a point of impingement to exceed the standard prescribed in Schedule 1. R.R.O. 1990, Reg. 346, s. 5 (3).

6. No person shall cause or permit to be caused the emission of any air contaminant to such extent or degree as may,

(a) cause discomfort to persons;
(b) cause loss of enjoyment of normal use of property;
(c) interfere with normal conduct of business; or
(d) cause damage to property. R.R.O. 1990, Reg. 346, s. 6.

7. (1) The Ministry shall prepare a chart to be known as the "Visible Emission Chart of the Province of Ontario". R.R.O. 1990, Reg. 346, s. 7 (1).

(2) The Visible Emission Chart of the Province of Ontario shall consist of two one-inch squares on a white background such that,

(a) the area within the square designated as number 1 shall have black dots or lines evenly spaced such that approximately 20 per cent of the area is black;
(b) the area within the square designated as number 2 shall have black dots or lines evenly spaced such that approximately 40 per cent of the area is black. R.R.O. 1990, Reg. 346, s. 7 (2).

(3) For the purpose of enforcing the Act and this Regulation no person other than a provincial officer who has been trained by the Ministry in the identification of opacity shall determine the opacity of a visible emission. R.R.O. 1990, Reg. 346, s. 7 (3).

8. (1) Subject to subsection (2), no person shall cause or permit to be caused a visible emission,

(a) having shades of grey darker than number 1 on the Visible Emission Chart of the Province of Ontario at the point of emission; or
(b) that obstructs the passage of light to a degree greater than 20 per cent at the point of emission. R.R.O. 1990, Reg. 346, s. 8 (1).

(2) A visible emission from a source of combustion employing solid fuel for a period of not more than four minutes in the aggregate in any thirty-minute period, may,

(a) be in shades of grey darker than number 1, but not darker than number 2 on the Visible Emission Chart of the Province of Ontario at the point of emission; or
(b) obstruct the passage of light to a degree greater than 20 per cent but no greater than 40 per cent at the point of emission. R.R.O. 1990, Reg. 346, s. 8 (2).

9. Where at any stationary source of air pollution a failure to operate in the normal manner or a change in operating conditions occurs, or a shut-down of the source or part thereof is made for some purpose, resulting in the emission of air contaminants that may result in quantities or concentrations in excess of those allowed in sections 5, 6 and 8,

(a) the owner or operator of the source of air pollution shall,
  (i) immediately notify a provincial officer and furnish him or her with particulars of such failure, change or shutdown, and
  (ii) furnish the provincial officer with the particulars in writing, as soon as is practicable, of such failure, change or shut-down; and
(b) if the provincial officer considers it advisable, the officer may authorize, in writing, the continuance of such operation for such period of time as he or she considers reasonable in the circumstances and may impose upon the owner or operator such terms and conditions for such continued operation as the officer considers necessary in the circumstances. R.R.O. 1990, Reg. 346, s. 9.

10. (1) No person shall burn or permit to be burned in any fuel burning equipment or incinerator any fuel or waste except the fuel or waste for the burning of which the equipment or incinerator was designed. R.R.O. 1990, Reg. 346, s. 10 (1).

(2) No person shall burn or permit to be burned in any fuel burning equipment or incinerator any fuel or waste at a greater rate than that rate for which the equipment or incinerator was designed. R.R.O. 1990, Reg. 346, s. 10 (2).

11. Except for heat, sound, vibration or radiation, no person shall,

(a) construct, alter, demolish, drill, blast, crush or screen anything or cause or permit the construction, alteration, demolition, drilling, blasting, crushing or screening of anything so that a contaminant is carried beyond the limits of the property on which the construction, alteration, demolition, drilling, blasting, crushing or screening is being carried out; or
(b) sandblast or permit the sandblasting of anything so that a contaminant is emitted into the air,

to an extent or degree greater than that which would result if every step necessary to control the emission of the contaminant were implemented. R.R.O. 1990, Reg. 346, s. 11.

12. (1) In this section,

"apartment incinerator" means an incinerator that is located in or on the site of a building containing more than one dwelling unit and used to burn domestic waste from more than one dwelling unit. R.R.O. 1990, Reg. 346, s. 12 (1).

(2) No person shall operate or permit the operation of,

(a) an apartment incinerator, domestic incinerator, multiple chamber incinerator or starved air incinerator burning domestic waste;

(b) a multiple chamber incinerator or starved air incinerator burning solid industrial waste;

(c) an incinerator burning liquid industrial waste, industrial slurries or sludges, sewage sludges or slurries, gaseous waste, organic vapour or fume; or

(d) a municipal incinerator burning solid waste or sludges,

that causes or is likely to cause a concentration in the combustion gases emitted into the natural environment, of organic matter having a carbon content, expressed as equivalent methane, being an average of ten measurements taken at approximately one minute intervals, greater than 100 parts per million by volume, measured on an undiluted basis. R.R.O. 1990, Reg. 346, s. 12 (2).

(3) Subsection (2) does not apply to prohibit the operation of a catalytic incinerator. R.R.O. 1990, Reg. 346, s. 12 (3).

(4) No person shall operate or permit the operation of an apartment incinerator without a certificate of approval issued under section 9 of the Act. R.R.O. 1990, Reg. 346, s. 12 (4).

13. No person shall store, handle or transport any solid liquid or gaseous material or substance in such manner that an air contaminant is released to the atmosphere. R.R.O. 1990, Reg. 346, s. 13.

Schedule 1

Item	Column 1	Column 2	Column 3
	Name of Contaminant	Unit of Concentration	Concentration at Point of Impingement - Half Hour Average
1.	Acetic Acid	Micrograms of acetic acid per cubic metre of air	2,500
2.	Acetylene	Micrograms of acetylene per cubic metre of air	56,000
3.	Acetone	Micrograms of acetone per cubic metre of air	48,000
4.	Acrylamide	Micrograms of acrylamide per cubic metre of air	45
4.1	Acrylonitrile	Micrograms of acrylonitrile per cubic metre of air	180
5.	Ammonia	Micrograms of ammonia per cubic metre of air	3,600
6.	Antimony	Total micrograms of antimony in free and combined form per cubic metre of air	75
7.	Arsine	Micrograms of arsine per cubic metre of air	10
8.	Beryllium	Total micrograms of beryllium in free and combined form per cubic metre of air	0.03
9.	Boron Tribromide	Micrograms of boron tribromide per cubic metre of air	100
10.	Boron Trichloride	Micrograms of boron trichloride per cubic metre of air	100
11.	Boron Trifluoride	Micrograms of boron trifluoride per cubic metre of air	5.0
12.	Boron	Total micrograms of boron in free and combined form per cubic metre of air	100
13.	Bromine	Micrograms of bromine per cubic metre of air	70
14.	Cadmium	Total micrograms of cadmium in free and combined form per cubic metre of air	5.0
15.	Calcium hydroxide	Micrograms of calcium hydroxide per cubic metre of air	27
16.	Calcium Oxide	Micrograms of calcium oxide per cubic metre of air	20
17.	Carbon Black	Micrograms of carbon black per cubic metre of air	25
18.	Carbon Disulphide	Micrograms of carbon disulphide per cubic metre of air	330
19.	Carbon Monoxide	Micrograms of carbon monoxide per cubic metre of air	6,000
20.	Chlorine	Micrograms of chlorine per cubic metre of air	300
21.	Chlorine Dioxide	Micrograms of chlorine dioxide per cubic metre of air	85

21.1	Chloroform	Micrograms of chloroform per cubic metre of air	300
22.	Copper	Total micrograms of copper in free and combined form per cubic metre of air	100
23.	Cresols	Micrograms of cresols per cubic metre of air	230
24.	Decaborane	Micrograms of decaborane per cubic metre of air	50
25.	Diborane	Micrograms of diborane per cubic metre of air	20
26.	Dicapryl Phthalate	Micrograms of dicapryl phthalate per cubic metre of air	100
27.	Dimethyl Disulphide	Micrograms of dimethyl disulphide per cubic metre of air	40
28.	Dimethyl Sulphide	Micrograms of dimethyl sulphide per cubic metre of air	30
29.	Dioctyl Phthalate	Micrograms of dioctyl phthalate per cubic metre of air	100
30.	Dustfall	Micrograms per square metre	8,000
31.	Ethyl Acetate	Micrograms of ethyl acetate per cubic metre of air	19,000
32.	Ethyl Acrylate	Micrograms of ethyl acrylate per cubic metre of air	4.5
33.	Ethyl Benzene	Micrograms of ethyl benzene per cubic metre of air	3,000
33.1	Ethyl Ether	Micrograms of ethyl ether per cubic metre of air	7,000
34.	Ferric Oxide	Micrograms of ferric oxide per cubic metre of air	75
35.	Fluorides, (Gaseous) (April 15 to October 15)	Micrograms of gaseous, inorganic fluoride per cubic metre of air expressed as hydrogen fluoride	4.3
36.	Fluorides, (Total) (April 15 to October 15)	Total micrograms of inorganic fluoride per cubic metre of air expressed as hydrogen fluoride	8.6
37.	Fluorides, (Total)	Total micrograms of inorganic	
	(October 16 to April 14)	fluoride per cubic metre of air expressed as hydrogen fluoride	17.2
38.	Formaldehyde	Micrograms of formaldehyde per cubic metre of air	65
39.	Formic Acid	Micrograms of formic acid per cubic metre of air	1,500
40.	Furfural	Micrograms of furfural per cubic metre of air	1,000
41.	Furfuryl Alcohol	Micrograms of furfuryl alcohol per cubic metre of air	3,000
41.1	*n*-Heptane	Micrograms of *n*-heptane per cubic metre of air	33,000
42.	Hydrogen Chloride	Micrograms of hydrogen chloride per cubic metre of air	100
43.	Hydrogen Cyanide	Micrograms of hydrogen cyanide per cubic metre of air	1,150
44.	Hydrogen Sulphide	Micrograms of hydrogen sulphide per cubic metre of air	30
45.	Iron (metallic)	Micrograms of metallic iron per cubic metre of air	10
45.1	Isopropyl Benzene	Micrograms of isopropyl benzene per cubic metre of air	100
46.	Lead	Total micrograms of lead in free and combined form per cubic metre of air	6
47.	Lithium Hydrides	Total micrograms of lithium hydrides per cubic metre of air	7.5
48.	Lithium	Total micrograms of lithium in other than hydride compounds per cubic metre of air	60
49.	Magnesium Oxide	Total micrograms of magnesium oxide per cubic metre of air	100
50.	Mercaptans	Total micrograms of mercaptans per cubic metre of air expressed as methyl mercaptans	20
51.	Mercury (alkyl)	Total micrograms of alkyl mercury compounds per cubic metre of air	1.5

52.	Mercury	Total micrograms of mercury in free and combined form per cubic metre of air	5.0
53.	Methyl Acrylate	Micrograms of methyl acrylate per cubic metre of air	4.0
54.	Methyl Alcohol (Methanol)	Micrograms of methyl alcohol per cubic metre of air	12,000
55.	Methyl Chloroform (1-1-1 Trichloroethane)	Micrograms of methyl chloroform per cubic metre of air	350,000
56.	Methyl Ethyl Ketone (2-Butanone)	Micrograms of methyl ethyl ketone per cubic metre of air	30,000
56.1	Methyl Isobutyl Ketone	Micrograms of methyl isobutyl ketone per cubic metre of air	1,200
57.	Methyl Methacrylate	Micrograms of methyl methacrylate per cubic metre of air	860
58.	Milk Powder	Micrograms of milk powder per cubic metre of air	20
58.1	Mineral Spirits	Micrograms of mineral spirits per cubic metre of air	7,800
59.	Monomethyl Amine	Micrograms of monomethyl amine per cubic metre of air	25
60.	Nickel	Total micrograms of nickel in free and combined form per cubic metre of air	5
61.	Nickel Carbonyl	Micrograms of nickel carbonyl per cubic metre of air	1.5
62.	Nitric Acid	Micrograms of nitric acid per cubic metre of air	100
63.	Nitrilotriacetic Acid	Micrograms of nitrilotriacetic acid per cubic metre of air	100
64.	Nitrogen Oxides	Micrograms of nitrogen oxides per cubic metre of air expressed as NO_2	500
65.	Ozone	Micrograms of ozone per cubic metre of air	200
66.	Pentaborane	Micrograms of pentaborane per cubic metre of air	3.0

67.	Phenol	Micrograms of phenol per cubic metre of air	100
68.	Phosgene	Micrograms of phosgene per cubic metre of air	130
69.	Phosphoric Acids	Micrograms of phosphoric acids per cubic metre of air expressed as P_2O_5	100
70.	Phthalic Anhydride	Micrograms of phthalic anhydride per cubic metre of air	100
71.	Propylene Dichloride	Micrograms of propylene dichloride per cubic metre of air	2,400
71.1	Propylene Oxide	Micrograms of propylene oxide per cubic metre of air	450
72.	Silver	Total micrograms of silver in free and combined form per cubic metre of air	3
73.	Styrene	Micrograms of styrene per cubic metre of air	400
74.	Sulphur Dioxide	Micrograms of sulphur dioxide per cubic metre of air	830
75.	Sulphuric Acid	Micrograms of sulphuric acid per cubic metre of air	100
76.	Suspended Particulate Matter (particulate less than 44 microns in size)	Total micrograms of suspended particulate matter per cubic metre of air	100
77.	Tellurium (except hydrogen telluride)	Micrograms of tellurium in free and combined form per cubic metre of air	30
78.	Tetrahydrofuran	Micrograms of tetrahydrofuran per cubic metre of air	93,000
79.	Tin	Total micrograms of tin in free and combined form per cubic metre of air	30
80.	Titanium	Total micrograms of titanium in free and combined form per cubic metre of air	100
81.	Toluene	Micrograms of toluene per cubic metre of air	2,000
82.	Toluene Di-isocyanate	Micrograms of toluene di-	1.0

		isocyanate per cubic metre of air	
83.	Trichloroethylene	Micrograms of trichloroethylene per cubic metre of air	3,500
84.	Trifluorotrichloro Ethane	Micrograms of trifluoro trichloroethane per cubic metre of air	2.4 million
85.	Vanadium	Total micrograms of vanadium in free and combined form per cubic metre of air	5.0
85.1	Vinylidene Chloride	Micrograms of vinylidene chloride per cubic metre of air	30
86.	Xylenes	Micrograms of xylenes per cubic metre of air	2,300
87.	Zinc	Total micrograms of zinc in free and combined form per cubic metre of air	100

R.R.O. 1990, Reg. 346, Sched.; O. Reg. 795/94, s. 1; O. Reg. 342/01, s. 1.

Back to top

Québec

Updated to 26 November 2002

c. Q-2, r. 20

Regulation respecting the quality of the atmosphere

Environment Quality Act
(R.S.Q., c. Q-2, ss. 20, 31, 53, 70, 71, 72, 87 and 124.1)

DIVISION IV
OPACITY OF EMISSIONS

10. Opacity standards: Subject to the cases provided for in sections 35, 36, 41 and 84, the concentration of contaminants discharged into the atmosphere by a stationary source must not exceed 20 % of opacity according to one or the other of the measuring methods provided for in paragraphs *a* or *b* of section 96.

R.R.Q., 1981, c. Q-2, r. 20, s. 10.

11. Exceptions: Section 10 does not apply to the starting of a fire or the soot blowing. The degree of opacity may then, for a maximum period of 4 consecutive minutes exceed 20 % but never be equal to or higher than 60 % of opacity.

During the operation of a stationary source, the degree of opacity of an emission may also exceed 20 % for one or several periods not exceeding 4 minutes in any one hour, but never be equal to or higher than 40 %.

R.R.Q., 1981, c. Q-2, r. 20, s. 11.

DIVISION V
EMISSION OF ORGANIC COMPOUNDS

12. General standards: Subject to cases provided for in sections 13 and 14, a stationary source other than those mentioned in section 15 may not emit into the atmosphere:

(a) more than 6,8 kilograms per day and 1,3 kilograms per hour of organic compounds in the case where organic solvents or substances which contain them are submitted to a baking process or come in contact with a flame;

(b) more than 15 kilograms per day and 3 kilograms per hour of organic compounds for photochemically reactive organic compounds which are not submitted to a baking process or do not come in contact with a flame;

(c) more than 1 400 kilograms per day or 200 kilograms per hour of organic compounds where non-photochemically reactive solvents are not submitted to a baking process or do not come in contact with a flame.

For the purposes of enforcing this section, the different portions of a continuing process constitute only one stationary source. Organic compound emissions mentioned in subparagraphs *b* and *c* of the first paragraph comprise all emissions produced during the 12 hours used for drying, following the last application of organic solvents or substances which contain them.

R.R.Q., 1981, c. Q-2, r. 20, s. 12.

13. Excessive emissions: Organic compound emissions may exceed the standards prescribed in section 12 provided that there is a reduction of the emissions in the atmosphere of at least 90 % for incineration of organic compounds and at least 85 % in other cases.

R.R.Q., 1981, c. Q-2, r. 20, s. 13.

14. Restrictions: Sections 12 and 13 do not apply to:

(a) establishments where organic solvents are made;

(b) the transport and storage of organic solvents or substances which contain them;

(c) the use of insecticides, pesticides or herbicides; nor

(d) to the use or evaporation of halogen hydrocarbons.

R.R.Q., 1981, c. Q-2, r. 20, s. 14.

15. Shops, or coating or impregnation rooms for organic compounds or paint: A shop or coating or impregnation room for organic compounds or paint containing photochemically reactive organic compounds the discharge of which in the atmosphere exceeds 15 kilograms per day, cannot discharge organic compounds into the atmosphere beyond the standards of the following table:

TABLE

```
[Q-2r20#03, see R.R.Q., 1981, 8-716]

category

type of coating emission standard
(in kg of organic compound
per litre of  produit used)
 can factory    primer and metal sheet
 lacquer      0,34
        can interior and top
 coating      0,51
        weld coating  0,66
        sealing compound     0,44
 electric cable plant   coating       0,31
 textile plant  fabric coating process       0,35
        vinyl coating 0,45
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 coated paper plant     impregnation  0,35
 motor vehicle
 assembly plant  primer coating 0,23
        finish coating 0,34
        touch-up, final repair       0,58
 motor vehicle repair shop
 and any other shop or
 coating or impregnation room



 all operations



0,58
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[Q-2r20#03, FIN]

In addition to the standards prescribed in the first paragraph, a new or existing paint room must:

(a) be equipped with a particulate matter collection system designed to collect more than 90 % of the particulate matters discharged in the atmosphere;

(b) be equipped with a gas exhaust stack at least 5 metres taller than the building in which painting operations take place; and

(c) exhaust the gases into the atmosphere with an updraft speed of at least 15 metres per second.

The emission standards for organic compounds provided for in this Division apply from 1 June 1981 to existing stationary sources.

R.R.Q., 1981, c. Q-2, r. 20, s. 15; O.C. 187-88, s. 1.

This section applies in particular to immoveables comprised in a reserved area and in agricultural zone established under the Act preserve agricultural land (R.S.Q., c. P-41.1).

15.1. Paint shops in a light motor vehicle assembly plant:

No person who sets up or modifies a paint shop or room which is part of a light motor vehicle assembly plant may allow the emission into the atmosphere of organic compounds in excess of the standards prescribed in the following table:

[Q-2r20#23, see 1988 G.O. 2, 1268]

```
        Emission standards in kg of organic compounds
per
 litre of solids applied
Operation              Existing plant
        New
plant   Standard up
to 30 Sept.
1989    Standard from
1 Oct. 1989 to
31 Dec. 1992   Standard from
1 January
1993
 Prime
 coat   0,16    0,43    0,43    0,.16
 Guide
 coat   1,40    5,57    1,40    1,40
 Top
 coating        1,89    11,92   3,72    1,89
```

[Q-2r20#23, FIN]

The operator of a motor vehicle assembly plant must make available to the Ministère de l'Environnement et de la Faune the monthly readings giving the average monthly quantity of volatile organic compounds emitted per volume unit of solids applied to bodies, and also the volume of paint used, the percentage of solids in such paint, the quantity of diluting solvents added, the actual transfer efficiency ratio, and any other information necessary for the computation of emissions. Such computation shall be done with the method established by legislation of the United States, reference 40CFR 60.393.

The standards prescribed in the second paragraph of section 15 shall apply to a shop or room governed by this section.

O.C. 187-88, s. 2; S.Q., 1994, c. 17, s. 77.

This section applies in particular to immoveables comprised in a reserved area and in agricultural zone established under the Act to preserve agricultural land (R.S.Q., c. P-41.1).

DIVISION VII
FUGITIVE EMISSIONS

17. Dust emissions: Any person who wrecks, builds, repairs or maintains a building or a thoroughfare must spread water or another dust control product to prevent the raising of dust in all cases where the carrying out of such activity brings about the emission of dust which produces any effect enumerated in the second paragraph *in fine* of section 20 of the Act.

R.R.Q., 1981, c. Q-2, r. 20, s. 17.

18. Access lanes, storage and transport: When dust emissions from access lanes and road ways located on the same property as a stationary source or a pile of aggregates, materials, mine refuse, ore, ore concentrate or pellets produce any effect enumerated in the second paragraph *in fine* of section 20 of the Act, the person responsible for the contamination source must take the necessary measures to control these emissions so as to eliminate those effects.

This section applies, *mutatis mutandis,* to the transport by conveyor belt, truck or railway car of the materials mentioned in the first paragraph.

R.R.Q., 1981, c. Q-2, r. 20, s. 18.

19. Transfer and free fall: In the case where the transfer or free fall of materials of any kind including aggregates, mine rejects ore, ore concentrate or pellets, brings about the emission of dust which can be seen in the atmosphere more than 2 metres away from the emission source, the person responsible for that source of atmospheric contamination must take the necessary measures so that:

(a) the stationary transfer point is included in an enclosed space equipped with ducts which draw dust to a dust collector so that the emissions of particulate matters into the atmosphere are in compliance with the concentration standard established in section 25; or

(b) the free fall height of these materials does not exceed 2 metres.

R.R.Q., 1981, c. Q-2, r. 20, s. 19.

20. Sandblasting: Dust emissions resulting from dry sandblasting operations must be controlled by using an enclosure or screen in order to confine the dust inside the spaces thus enclosed or closed, except in the case of a metal bridge.

This section applies, *mutatis mutandis,* to wet-type sandblasting operations when there are dust emissions that can be seen in the atmosphere more than 2 metres from the emission source.

R.R.Q., 1981, c. Q-2, r. 20, s. 20.

21. Recuperated dust: Dust recuperated by a dry collector must be handled and transported so that there is no dust released into the atmosphere which can be seen 2 metres from the emission source. When it is not recycled, it must be stored, spread or disposed of on the ground and the necessary measures must be taken to prevent any release of dust into the atmosphere which can be seen 2 metres away from the emission source, and in order to prevent water contamination.

R.R.Q., 1981, c. Q-2, r. 20, s. 21.

22. Waste: It is forbidden to burn residual materials in the open air, even to recuperate it in part or in whole, except for limbs, trees, dead leaves, explosives and empty containers of explosives.

The presence in the environment of smoke originating from combustion prohibited by the first paragraph is prohibited within the meaning of the second paragraph of section 20 of the Act.

This section does not apply to solid waste disposal sites situated north of the 55th parallel, nor to those mentioned in Division X or in section 125 of the Regulation respecting solid waste (c. Q-2, r. 14). The person responsible for such a solid waste disposal site must however take the necessary measure to prevent smoke emissions from producing one effect or the other enumerated in the second paragraph *in fine* of section 20 of the Act.

R.R.Q., 1981, c. Q-2, r. 20, s. 22; O.C. 492-2000, s. 9.

23. Disposal of fuels: It is forbidden to burn fossil fuels or organic compounds in the open air unless one has been issued a certificate of authorization by the Minister under section 22 of the Act.

This section does not apply to industrial flares, nor within the scope of the training given to firemen.

R.R.Q., 1981, c. Q-2, r. 20, s. 23; S.Q., 1988, c. 49, s. 54; O.C. 1544-92, s. 2.

DIVISION VIII
PARTICULATE MATTER GENERAL EMISSION STANDARDS

24. Quantities allowed: Except for the special cases provided for in Divisions IX to XV, XVII to XXII, XXIV, XXVI to XXVIII and in section 25, no one may emit particulate matters into the atmosphere in excess of the hourly quantities allowed respectively for existing and new stationary sources in Schedules A and B.

Moreover, a new grain processing plant whose nominal drying capacity is greater than 15 tonnes per hour for a reduction of 15 points in the grain humidity, must be placed at least 300 metres from a dwelling area established by a municipality or from a dwelling situated in the direction of the prevailing wind and more than 150 metres from any other dwelling, except for the one belonging to or rented by the owner or operator of the grain processing plant. For the purpose of enforcement of this paragraph, a prevailing wind is a wind which, from August to November inclusively blows in average of 20 % of the time in one direction in the case where a compass dial with 8 directions is used and more than 10 % of the time in the case where a compass dial with 16 directions is used, as measured at the meteorological station nearest to the plant.

R.R.Q., 1981, c. Q-2, r. 20, s. 24.

25. Concentration: No mill, distillery, brewery, powder milk plant, fertilizer mixing plant, concrete plant, vitreous enamel, earthenware, and ceramic products plant, polyvinyl chloride production or processing plant or wood processing plant must emit particulate matter into the atmosphere with a concentration higher than 50 milligrams per cubic metre, under standard conditions.

This standard applies also to emissions coming from any transfer of bulk material except wood, any storage in confined environment, any digging other than the sinking of a supply water well, any welding operation metal works in indoor sandblasting and to any process for the preparation, concentration, agglomeration or drying of ore or ore concentrate, as well as to the related handling operations done in a plant for the preparation, concentration, agglomeration or drying of metallic ores, except for the process of aluminium hydrate calcining.

R.R.Q., 1981, c. Q-2, r. 20, s. 25.

26. Date of enforcement: This Division applies from 1 December 1981 to existing stationary sources except to existing mills which will be subject to it from 1 December 1983.

R.R.Q., 1981, c. Q-2, r. 20, s. 26.

DIVISION IX
USE OF FOSSIL FUELS

27. Particulate matter emissions: A fossil fuel burning equipment cannot emit particulate matters into the atmosphere beyond the standards prescribed in the following table:

TABLE

[Q-2r20#04, see R.R.Q., 1981, 8-718]

emission standards
(particulate matters mg per MJ)
heat input capacity
in fuel as fired
type of fuel
new installation
existing installation*
between 3 and 15 MW gas or oil
product 60 85
between 3 and 70 MW coal 60 85
Š 15 MW gas or oil
product 45 60
Š 70 MW coal 45 60
* the standards prescribed in this section apply from 1 June, 1981 to existing fuel burning equipments.

[Q-2r20#04, FIN]

In the case of an existing fuel burning equipment with a capacity greater than 125 megawatts, used in an electric power plant, the emission standard is 45 milligrams per megajoule and applies from 1 December 1980.

R.R.Q., 1981, c. Q-2, r. 20, s. 27.

28. Nitrogen oxide emissions: A new fuel burning equipment fuel is used must not emit nitrogen oxides into the atmosphere beyond the standards prescribed in the following table:

TABLE

[Q-2r20#05, see R.R.Q., 1981, 8-719]

heat input
capacity
as fired type
of fuel emission
standards
(ppm, dry
basis
to 3% 02)
Š 70 MW coal 500
oil 250
gas 200
between 15 and
70 MW coal 450
oil 325
gas 150

[Q-2r20#05, FIN]

R.R.Q., 1981, c. Q-2, r. 20, s. 28.

29. Sulfur content: No person may burn a fuel with a sulfur content higher than:

(a) 2,0 % in weight for heavy oil;

(b) 1,0 % in weight for intermediate oil;

(c) 0,5 % in weight for light oil; and

(d) 2,0 % in weight for coal.

Notwithstanding subparagraph *a* of the first paragraph, the person in charge of an establishment who, on 1 June 1990, has in his possession, in tanks belonging to him, heavy oil with a sulfur content of between 2,0 % and 2,5 % may use that oil for combustion purposes before 31 December 1990 provided that:

(a) he send notice thereof to the Minister before 1 July 1990 indicating the quantity, sulfur content and date of purchase and of delivery of the heavy oil in his possession with a sulfur content of between 2,0 % and 2,5 %;

(b) he use, before 31 December 1990, a quantity of heavy oil with a sulfur content of less than 2,0 % so that the total sulfur dioxide emissions of the establishment for the last 7 months of 1990 is equal to or less than the sulfur dioxide emissions that would have resulted from the combustion of the same total quantity of heavy oil with a sulfur content of 2,0 %.

A person availing himself of the provisions of the second paragraph shall, before 30 January 1991, send the Minister a report indicating, for all the oil used during the last 7 months of 1990, the sulfur content and the quantity of that oil.

R.R.Q., 1981, c. Q-2, r. 20, s. 29; O.C. 715-90, s. 1.

30. Exception: Standards prescribed in section 29 for heavy oil and coal do not apply in cases where:

(a) a portion of the sulfur contained in the flue gases is recovered and combined to a raw material coming in contact with these gases;

(b) a portion of the sulfur contained in the flue gases is retained by a gas cleaning equipment; or

(c) another fossil fuel with a low sulfur content is used simultaneously in an oil refinery.

The person in charge of an establishment to which one of the exceptions prescribed in the first paragraph applies must keep a record book in which he enters the origin, quantity and sulfur content of the heavy oil and coal used; in the case provided for in subparagraph *c* of the first paragraph, he must also enter in this record book, at least twice a week, the nature, quantity, sulfur content and heating value of each fossil fuel used.

He must forward this record book to the Minister at the end of each calendar year.

R.R.Q., 1981, c. Q-2, r. 20, s. 30; O.C. 240-85, s. 4; S.Q., 1988, c. 49, s. 54; O.C. 715-90, s. 2.

31. Sulfur dioxide emissions: Notwithstanding section 30, the quantity of sulfur dioxide emitted into the atmosphere by burning any fossil fuel must not exceed that emitted by burning a quantity equivalent in heating value of heavy oil whose sulfur content does not exceed the standards prescribed in section 29.

R.R.Q., 1981, c. Q-2, r. 20, s. 31; O.C. 240-85, s. 5.

31.1. Notwithstanding section 29, the person in charge of fuel burning equipment installed after 1 June 1990 may not use, as fuel, heavy oil or coal with a sulfur content of more than 1,5 % in weight.

O.C. 715-90, s. 3.

32. Exhaust gas venting: The exhaust speed of flue gases into the atmosphere from a new fuel burning equipment fired with heavy oil or coal must be at least 15 metres per second at the outlet of a new stack when the equipment operates at nominal capacity.

R.R.Q., 1981, c. Q-2, r. 20, s. 32.

33. Stack: The minimum height of any new stack of a fuel burning equipment using heavy oil or coal must be equal at least to the one computed in conformity with the method entitled *Méthode de calcul de la hauteur minimale des cheminées* published in 1979 by the Services de protection de l'environnement.

The height of an existing stack cannot be reduced unless it still is, after reduction, in conformity with the height computed according to the method provided for in the first paragraph.

R.R.Q., 1981, c. Q-2, r. 20, s. 33.

34. Prohibited emissions: Notwithstanding sections 29 to 33, an establishment equipped with fuel burning equipment cannot emit sulfur dioxide into the atmosphere in such manner as to exceed quality standards prescribed for sulfur dioxide in section 6.

R.R.Q., 1981, c. Q-2, r. 20, s. 34.

35. Gas turbines: A gas turbine cannot emit into the atmosphere:

(a) a concentration of contaminants exceeding 10 % of opacity according to one or the other of the methods of measure provided for in paragraphs *a* or *b* of section 96, in the case of a simple gas turbine;

(b) more than 0,2 grams of particulate matters by megajoule, in the case of a new combined gas turbine;

(c) more than 1,3 grams of nitrogen oxides by megajoule.

R.R.Q., 1981, c. Q-2, r. 20, s. 35.

36. Stationary internal combustion engines: A stationary internal combustion engine cannot emit into the atmosphere:

(a) a concentration of contaminants exceeding 10 % of opacity according to one or another method of measurement provided for in paragraphs *a* or *b* of section 96 in the case of a new engine;

(b) more than 4,5 grams of nitrogen oxides by megajoule in the case of an engine with a capacity equal to or greater than 1 megawatt and 2,2 grams of nitrogen oxides per megajoule in the case of a smaller engine;

(c) more than 1,8 grams of carbon monoxide per megajoule in the case of an engine with a capacity equal to or higher than 1 megawatt and 0,65 grams of carbon monoxide in the case of a smaller engine;

(d) more than 2,2 grams of hydrocarbons per megajoule in the case of an engine with a capacity equal to or greater than 1 megawatt where gas or a dual fuel is used and 0,28 grams of hydrocarbons per megajoule in the case of an engine with a capacity equal to or greater than 1 megawatt where diesel fuel or light oil is used and in the case of an engine with a capacity smaller than 1 megawatt.

R.R.Q., 1981, c. Q-2, r. 20, s. 36.

DIVISION XXVI
IRON ORE PELLETIZING PLANTS

86. Indurating process: The indurating process of an iron ore pelletizing plant must not emit into the atmosphere particulate matter in excess of that prescribed in the following table:

TABLE

`[Q-2r20#17, see R.R.Q., 1981, 8-727]`

type of plant	standard
new plant of any capacity	0,10 kg/tonne of pellets produced*
existing plant with a nominal yearly production lower than 1 500 000 tonnes of iron oxide pellets	0,36 kg/tonne of pellets produced*
existing plant with a nominal yearly capacity equal to or greater than 1 500 000 tonnes of iron oxide pellets	0,12 kg/tonne of pellets produced*

[Q-2r20#17, FIN]

* Including the recirculating load, if applicable.

R.R.Q., 1981, c. Q-2, r. 20, s. 86.

87. Date of enforcement: This Division applies from 1 December 1981 to existing iron ore pelletizing plant.

R.R.Q., 1981, c. Q-2, r. 20, s. 87.

SCHEDULE A

(s. 24)

[Q-2r20#19, see R.R.Q., 1981, 8-730]

process weight rate (tonnes/h)	emission standards kg/h
0,50	1,3
1,00	2,0
1,50	2,6
2,00	3,2
2,50	3,7
3,00	4,2
3,50	4,6
4,00	5,1
4,50	5,5
5,00	5,9
6,00	6,6
7,00	7,4
8,00	8,1
9,00	8,7
10,0	9,4
12,0	10,6
15,0	12,3
17,0	13,3
20,0	14,9
22,0	15,8
25,0	17,2
27,0	17,5
30,0	18,0
35,0	18,6
40,0	19,1
45,0	19,6
50,0	20,0
60,0	20,8
70,0	21,5
80,0	22,1
90,0	22,6
100	23,0
150	25,0
200	26,4
250	27,5
300	28,4
350	29,2
400	29,9
450	30,6
500	31,1
550	31,6
600	32,1

[Q-2r20#19, FIN]

N.B. The process weight rate is determined by the total weight of all materials introduced into any process for a specified period of time. For the purpose of this Schedule, solid fuels are considered part of the process, but liquid and gaseous fuels and combustion air are not.

Interpolation of the data in this Schedule for process weight rates under 25t/h shall be accomplished by use of the equation $E = 2{,}0p^{0.67}$ and interpolation and extrapolation of the data for process weight rates equal to or in excess of 25 t/h shall be accomplished by use of the equation $E = 25{,}0p^{0.11}$--18, where E is the emission standard in kg/h and P is the process weight rate in t/h.

In the case of discontinuous operation of the process, the rate is calculated by dividing the total process weight rate by the number of hours of complete operations, less the time during which the equipment was not in operation. The process weight rate per hour is then calculated by dividing the process weight rate for a typical period of time by the number of hours of such period.

R.R.Q., 1981, c. Q-2, r. 20, Sch. A.

SCHEDULE B

(s. 24)

[Q-2r20#20, see R.R.Q., 1981, 8-730]

process weight rate (tonnes/h)	emission standards (kg/h)
0,50	1,1
1,00	1,7
1,50	2,2
2,00	2,6
2,50	3,0
3,00	3,4
3,50	3,7
4,00	4,0
4,50	4,3
5,00	4,6
6,00	5,2
7,00	5,7
8,00	6,2
9,00	6,6
10,0	7,1
12,0	7,9
15,0	9,1
17,0	9,8
20,0	10,9
22,0	11,6
25,0	13,4
27,0	13,6
30,0	13,8
35,0	14,1
40,0	14,4
45,0	14,7
50,0	15,0
60,0	15,4
70,0	15,8
80,0	16,1
90,0	16,4
100	16,7
150	17,8
200	18,7
250	19,4
300	19,9
350	20,4
400	20,9
450	21,3
500	21,6
550	22,0
600	22,3

[Q-2r20#20, FIN]

N.B. The process weight rate is determined by the total weight of all materials introduced into any process during a specified period of time. For the purpose of this Schedule, solid fuels are considered part of the process, but liquid and gaseous fuels and combustion air are not.

Interpolation of the data in this Schedule for process weight rates under 25 t/h shall be accomplished by use of the equation $E = 1{,}7p^{0.62}$ and interpolation and extrapolation of the data for process weight rate equal to or in excess of 25 t/h shall be accomplished by use of the equation $E = 8p^{0.16}$ standard in kg/h and P is the process weight rate in t/h.

In the case of discontinuous operation of the process, the process weight rate is calculated by dividing the total process weight rate by the number of hours of complete operations, less the time during which the equipment was not in operation. The process weight rate per hour is then calculated by dividing the process weight rate for a typical period of time by the number of hours of such period.

R.R.Q., 1981, c. Q-2, r. 20, Sch. B.

SCHEDULE C

(s. 96)

SCALE FOR THE MEASUREMENT OF THE OPACITY OF GRAY OR BLACK EMISSIONS INTO THE ATMOSPHERE

[Q-2r20#21, see R.R.Q., 1981, 8-731]

No. 1 No. 2 No. 3 No. 4

MICRO-RINGELMANN SCALE
MINISTÈRE DE L'ENVIRONNEMENT
GOUVERNEMENT DU QUÉBEC

[Q-2r20#21, FIN]

Definitions

1. Select an observation point situated at more than 30 metres and less than 400 metres from the source of emission.

2. Avoid looking towards bright sunlight and select an observation angle free of dark objects in the background.

3. Hold the chart at arm's length and look at the emission through the slip.

4. Record the scale number corresponding to the opacity, including the number 0 corresponding to white over white.

5. To calculate the opacity of an emission record the numbered shades on the scale and use the following formula:

```
[Q-2r20#22, see R.R.Q., 1981, 8-731]

P=      NEU at opacity No. 1 X 20%

                 number of observations

[Q-2r20#22, FIN]
```

where P designates the percentage of opacity of the emissions and NEU designates the number of equivalent units.

The number of each numbered shade constitutes as many equivalent units.

6. Only one observation is enough for the enforcement of section 10.

R.R.Q., 1981, c. Q-2, r. 20, Sch. C.

R.R.Q., 1981, c. Q-2, r. 20

O.C. 240-85, 1985 G.O. 2, 1011

O.C. 1004-85, 1985 G.O. 2, 2043

O.C. 187-88, 1988 G.O. 2, 1267

O.C. 715-90, 1990 G.O. 2, 1422

O.C. 584-92, 1992 G.O. 2, 2517

O.C. 1544-92, 1992 G.O. 2, 4863

O.C. 448-96, 1996 G.O. 2, 2107

O.C. 1310-97, 1997 G.O. 2, 5199

O.C. 492-2000, 2000 G.O. 2, 2090

ATTACHMENT R

RBLC Taconite Industry Query Results

DETAILED SOURCE LISTING
Report Date: 04/15/2003

Facility Information

RBLC ID:	MN-0036 (final)	**Date Last Updated:**	10/09/2002
Company Name:	ISPAT INLAND MINING CO.	**Permit/File No.:**	13700062-001
Plant Name:	ISPAT INLAND MINING CO.	**Permit Date:**	01/14/2000 (actual)
EPA Region:	5	**SIC Code:**	1011
County/State:	ST. LOUIS / MN	**NAICS:**	22221
Permit Issued By:	MINNESOTA POLL CTRL AGCY, AIR QUAL DIV (agency) HONGMING JIANG (contact) 651-296-7670		
Plant Description:	TACONITE PROCESSING		
Notes:	A Psd Permit, Issued on 9/25/87, Gave an Erroneous Nox Emission Limit for the Indurating Machine, Which Would Be Fitted with Low NOx Burners. It Is Now Corrected with the Facility's Title V Permit, after a Thorough Backward- Looking PSD Review. The Limit Is Raised, Without Any New Add-on Control.		

Process/Pollutant Information

PROCESS:	METAL ORE MINING, TACONITE, INDURATING FURNACE		
Process Type:	90.031 (Taconite Iron Ore Processing)		
Primary Fuel:	NATURAL GAS	**SCC Code:**	30302312
Throughput:	370 MMBTU/H	**Compliance Verified:**	No
Process Notes:	ADDITIONAL THROUGHPUT: 400 T PELLETS/HR. MAIN BURNERS ARE GAS FIRED WITH OIL AS BACKUP FUEL. PREHEAT BURNERS ARE GAS FIRED ONLY. FERROUS IRON IN TACONITE HELPS REDUCE ENERGY DEMAND. BUT FERROUS IRON CONTENT CANNOT BE CONTROLLED. TESTING INCLUDES PRODUCTION AND FUEL USE DATA OVER 12 MO. ROLLING AVERAGE. ONLY NO2 REQUIRED BACT DETERMINATION.		

POLLUTANT: NO2 **CAS No.:** 10102-44-0

Emission Limit 1:	1088 LB/H	**Basis:**	BACT-PSD
Emission Limit 2:		**% Efficiency:**	
Standard Emission:			
Control Method:	(P) FUEL USE IS LIMITED TO 270 MMBTU/HR FOR ALL EU26 BURNERS COMBINED (4 STACKS) IN ADDITION TO THE USE OF EXISTING LOW NOX BURNERS. 11 CONTROL OPTIONS EXAMINED.		
Pollutant Notes:			

ATTACHMENT S

August 25, 2003, Barr Memorandum “CALPUFF Screening Protocol for Taconite Industry BART Project” sans Attachments

Barr Engineering Company
4700 West 77th Street • Minneapolis, MN 55435-4803
Phone: 952-832-2600 • Fax: 952-832-2601

Minneapolis, MN • Hibbing, MN • Duluth, MN • Ann Arbor, MI • Jefferson City, MO

Memorandum

To: Stuart Arkley and Margaret McCourtney, MPCA

From: Joel Trinkle and Eric Edwalds, Barr

Subject: CALPUFF Screening Protocol for Taconite Industry BART Project

Date: August 25, 2003

Project: 23/62-833-BART-OP2

c:

Pursuant to a request made during our phone call with Ms. McCourtney on August 18, Barr is providing for your review a visibility screening protocol with parameter values that we propose to use in CALPUFF for modeling taconite industry BART-eligible sources. To conserve time, this protocol highlights the primary aspects of the modeling analysis in a memorandum rather than in a formal report.

Objective

The purpose of the visibility screening effort is to better understand the pollutants of concern for visibility from the taconite industry as well as to inform the taconite industry on visibility impacts from the its emission sources.

Modeling Program

The CALMET/CALPUFF/CALPOST system will be used in this analysis. Attachment A contains an example CALPUFF input file with the proposed control options to be used in the analysis. The source input data will be added to the control file upon approval to begin work. The CALMET component of the model was conducted for a previous client; Attachment B contains a CALMET input file. The previous CALPUFF and CALMET analysis was approved in general by John Notar of the National Park Service before the project was subsequently cancelled.

Sources

Consistent with Table 5-1 of the draft Taconite BART Report (July 11, 2003), four ‘typical’ sources will be modeled: grate/kiln furnace, straight grate furnace, pellet cooler, and ore handling. One representative stack will be used for each of the sources, for a total of four modeled sources. The following table contains the stack parameters that will be used in the modeling. Flow rate and temperature parameters were taken from Table 5-1. The stack height and stack diameter parameters were estimated from taconite source data in the MPCA Delta Database. All of the stack parameters represent a typical stack configuration rather than a "worst-case" stack.

Taconite BART Study

CALPUFF Stack Parameters

	English Units			
	Height	Temperature	Flow	Diameter
	Ft	F	acfm	Ft
Straight Grate Furnace	140	135	188,865	8
Grate/Kiln Furnace	140	135	377,730	13
Pellet Cooler	135	800	239,425	13
Ore Handling	80	77	7,143	2

	Metric Units			
	Height	Temperature	Velocity	Diameter
Source Type	M	K	m/s	m
Straight Grate Furnace	42.7	330	19	2.4
Grate/Kiln Furnace	42.7	330	14	4.0
Pellet Cooler	41.1	700	9	4.0
Ore Handling	24.4	298	12	0.6

Stack parameters for temperature and velocity (Normal Flow acfm) from Table 5-1 "Taconite Model Source Characteristics for BART Screening Evaluation"
Stack parameters for height and diameter are approximate average values estimated from stack data in MPCA Delta Database.

We will not model fugitive sources for the following reasons:

- Only one facility included fugitive sources in the BART-eligible survey, indicating that most fugitive sources are either not BART-eligible or were specifically excluded in the survey.

- Fugitive emissions tend to be coarse particulates, which in generanl are not the drivers for visibility degradation as compared to sulfates, nitrates, and fine particulate matter.
- All of the taconite facilities have fugitive dust control plans, as described in the draft BART report; therefore, BART for fugitive sources would likely not be different from what is already in the fugitive dust control plans.

Pollutants

CALPUFF allows for the specification of the pollutants to be modeled (Input Group 3A, 3B). Because there is limited information on the pollutants to be modeled, we propose the following:

	SPECIES NAME (Limit: 12 Characters in length)	MODELED (0=NO, 1=YES)	EMITTED (0=NO, 1=YES)	Dry DEPOSITED (0=NO, 1=COMPUTED-GAS 2=COMPUTED-PARTICLE 3=USER-SPECIFIED)	OUTPUT GROUP NUMBER (0=NONE, 1=1st CGRUP, 2=2nd CGRUP, 3= etc.)	
!	SO2 =	1,	1,	1,	0	!
!	SO4 =	1,	0,	2,	0	!
!	NOX =	1,	1,	1,	0	!
!	HNO3 =	1,	0,	1,	0	!
!	NO3 =	1,	0,	2,	0	!
!	PMC =	1,	1,	2,	0	!

Absent from the above pollutant list are fine particulates and elemental carbon due to lack of adequate emissions data.

Emission Rates:

Pre-BART Scenario

Only the four sources identified in Table 5-1 of the draft BART report will be included in the modeling. Only one pre-BART scenario will be modeled. Total industry emissions will be based on the 2001 emission inventory total (in Table 3-2 of the draft BART report) divided by a 0.85 capacity factor referenced in Hongming Jiang's paper on the taconite industry. The scaled-up 2001 industry emission totals will be apportioned into the four sources as shown in the table below, which reflect emissions from the source categories.

Post-BART Scenario

The post-BART emission rates will be equal to the pre-BART emission rates times the appropriate control efficiency for the selected BART. Some of the BART-eligible sources already have controls that would likely meet BART, so the incremental control efficiency dictated by BART for the taconite industry will likely be less than that shown for the individual control technologies in Table 6-1 of the draft BART report. Barr proposes to use a 30% reduction in NOx, SO2, and PM10 emission rates for the post-BART scenario. This is an estimate that will help provide an idea of the visibility reduction in relationship to an emissions reduction. It should not be construed to be an expected emissions reduction from the taconite industry due to application of BART.

Source	Pre-BART Emissions (tons)			Post-BART Emissions (tons)		
	PM10	SO2	NOx	PM10	SO2	NOx
Grate/Kiln	4595	6693	21395	3217	4685	14977
Straight Grate	358	331	4396	251	232	3077
Pellet Cooler	195	--	--	137	--	--
Ore Handling	1027	--	--	719	--	--

We are not considering additional modeling scenarios for the following reasons:

- The modeling has limited application. The purpose of the visibility screening effort is to better understand the pollutants of concern for visibility from the taconite industry as well as to inform the taconite industry on visibility impacts from the its emission sources.

- Simplifying assumptions that are made in the protocol introduce variability on an equal or greater scale than considering different emission scenarios.

Model Control Selections

The model receptor grid and location of the single plant to be modeled is illustrated as a figure in Attachment C. The base elevation for the modeled plant will be 475 m, which is the average of the five plants on the Mesabi range. Building downwash will not be included in the model. Barr will model one year of meteorological data (December 1984 through November 1985). Deposition will be included in the modeling. Other sources (non-taconite) will not be included in the modeling. We will use default values for the chemistry parameters with the following exceptions that were approved in a previous analysis by National Park Service:

Ozone Background:	40 ppm	(default is 80)
Ammonia Background:	1 ppm	(default is 10)

Results and Reporting

The purpose of the modeling is to assess the change in visibility due to the application of BART at the taconite facilities. The only change between the two model runs will be the emission rates for PM10, SO2 and NOx. Attachment D is an example spreadsheet file that will be developed for reporting the visibility results. One spreadsheet will be developed for each of the two scenario (pre- and post-BART), and the differences between the spreadsheets will be summarized in an additional spreadsheet table.

The results will be reported in the Taconite BACT Report, including a brief description of the modeling and model results.

ATTACHMENT T

CALMET Input File (One of Four Files)

```
MPCA Taconite BART Study
50 x 33  5 km meteorological grid
Q01 (12/1/84-2/28/85)
---------------- Run title (3 lines) ------------------------------------------

                    CALMET MODEL CONTROL FILE
                    --------------------------

-------------------------------------------------------------------------------

INPUT GROUP: 0 -- Input and Output File Names


Subgroup (a)
------------
Default Name  Type          File Name
------------  ----          ---------
GEO.DAT       input    ! GEODAT=C:\CALMETND\GEO.DAT       !
SURF.DAT      input    ! SRFDAT=L:\CALMET\SURFACE\SURF.DAT      !
CLOUD.DAT     input    * CLDDAT=            *
PRECIP.DAT    input    ! PRCDAT=L:\CALMET\PRECIP\PRECIP.DAT    !
MM4.DAT       input    * MM4DAT=            *
WT.DAT        input    * WTDAT=             *

CALMET.LST    output   ! METLST=L:\CALMET\OUTPUTB2\METQ01.LST     !
CALMET.DAT    output   ! METDAT=L:\CALMET\OUTPUTB2\METQ01.DAT    !
PACOUT.DAT    output   * PACDAT=            *

All file names will be converted to lower case if LCFILES = T
Otherwise, if LCFILES = F, file names will be converted to UPPER CASE
         T = lower case      ! LCFILES = T !
         F = UPPER CASE

NUMBER OF UPPER AIR & OVERWATER STATIONS:

    Number of upper air stations (NUSTA)  No default     ! NUSTA =  3  !
    Number of overwater met stations
                                 (NOWSTA) No default     ! NOWSTA =  0  !

                       !END!
--------------------------------------------------------------------------------
Subgroup (b)
---------------------------------
Upper air files (one per station)
---------------------------------
Default Name  Type       File Name
------------  ----       ---------
UP1.DAT       input     1  ! UPDAT=L:\CALMET\UPPER\UPSTCQ01.DAT!    !END!
UP2.DAT       input     2  ! UPDAT=L:\CALMET\UPPER\UPINLQ01.DAT!    !END!
UP3.DAT       input     3  ! UPDAT=L:\CALMET\UPPER\UPGRBQ01.DAT!    !END!
--------------------------------------------------------------------------------
Subgroup (c)
-----------------------------------------
Overwater station files (one per station)
-----------------------------------------
Default Name  Type       File Name
------------  ----       ---------
--------------------------------------------------------------------------------
Subgroup (d)
----------------
Other file names
----------------
```

```
Default Name  Type       File Name
------------  ----       ---------
DIAG.DAT      input      * DIADAT=                  *
PROG.DAT      input      * PRGDAT=                  *

TEST.PRT      output     * TSTPRT=                  *
TEST.OUT      output     * TSTOUT=                  *
TEST.KIN      output     * TSTKIN=                  *
TEST.FRD      output     * TSTFRD=                  *
TEST.SLP      output     * TSTSLP=                  *

--------------------------------------------------------------------------------
NOTES: (1) File/path names can be up to 70 characters in length
       (2) Subgroups (a) and (d) must have ONE 'END' (surround by
           delimiters) at the end of the group
       (3) Subgroups (b) and (c) must have an 'END' (surround by
           delimiters) at the end of EACH LINE

                         !END!


--------------------------------------------------------------------------------

INPUT GROUP: 1 -- General run control parameters
--------------

     Starting date:   Year (IBYR) -- No default       ! IBYR=  1984  !
                     Month (IBMO) -- No default       ! IBMO=  12  !
                       Day (IBDY) -- No default       ! IBDY=  1  !
                      Hour (IBHR) -- No default       ! IBHR=  1  !

     Base time zone        (IBTZ) -- No default       ! IBTZ=  6  !
        PST = 08, MST = 07
        CST = 06, EST = 05

     Length of run (hours) (IRLG) -- No default       ! IRLG=  2160  !

     Run type            (IRTYPE) -- Default: 1       ! IRTYPE=  1  !

        0 = Computes wind fields only
        1 = Computes wind fields and micrometeorological variables
            (u*, w*, L, zi, etc.)
        (IRTYPE must be 1 to run CALPUFF or CALGRID)

     Compute special data fields required
     by CALGRID (i.e., 3-D fields of W wind
     components and temperature)
     in additional to regular            Default: T    ! LCALGRD = F !
     fields ? (LCALGRD)
     (LCALGRD must be T to run CALGRID)

      Flag to stop run after
      SETUP phase (ITEST)             Default: 2       ! ITEST=  2   !
      (Used to allow checking
      of the model inputs, files, etc.)
      ITEST = 1 - STOPS program after SETUP phase
      ITEST = 2 - Continues with execution of
                  COMPUTATIONAL phase after SETUP

!END!

--------------------------------------------------------------------------------
```

```
INPUT GROUP: 2 -- Grid control parameters
--------------

     HORIZONTAL GRID DEFINITION:

            No. X grid cells (NX)      No default     ! NX =   50  !
            No. Y grid cells (NY)      No default     ! NY =   33  !

     GRID SPACING (DGRIDKM)            No default     ! DGRIDKM = 6. !
                                       Units: km

     REFERENCE COORDINATES
     of SOUTHWEST corner of grid cell (1,1)

        X coordinate (XORIGKM)         No default     ! XORIGKM = 453.368 !
        Y coordinate (YORIGKM)         No default     ! YORIGKM = 5217.226 !
                                       Units: km
        Latitude  (XLAT0)              No default     ! XLAT0 = 47.109 !
        Longitude (XLON0)              No default     ! XLON0 = 93.614 !

     UTM ZONE (IUTMZN)                 Default: 0     ! IUTMZN =  15  !

     LAMBERT CONFORMAL PARAMETERS

     Rotate input winds from true north to
     map north using a Lambert conformal
     projection? (LLCONF)              Default: F     ! LLCONF = F !

     Latitude of 1st standard parallel   Default: 30.   ! XLAT1 = 30.000 !
     Latitude of 2nd standard parallel   Default: 60.   ! XLAT2 = 60.000 !
     (XLAT1 and XLAT2; + in NH, - in SH)

        Longitude (RLON0)                Default = 90.  ! RLON0 = 90.000 !
        (used only if LLCONF = T)
        (Positive = W. Hemisphere;
         Negative = E. Hemisphere)
        Origin Latitude (RLAT0)          Default = 40.  ! RLAT0 = 40.000 !
        (used only if IPROG > 2)
        (Positive = N. Hemisphere;
         Negative = S. Hemisphere)

     Vertical grid definition:

        No. of vertical layers (NZ)    No default     ! NZ =  10  !

        Cell face heights in arbitrary
        vertical grid (ZFACE(NZ+1))    No defaults
                                       Units: m
        ! ZFACE = 0.,20.,50.,100.,200.,400.,800.,1200.,1600.,2000.,3600.  !

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 3 -- Output Options
--------------


    DISK OUTPUT OPTION

       Save met. fields in an unformatted
       output file ?              (LSAVE)  Default: T     ! LSAVE = T !
```

```
   (F = Do not save, T = Save)

   Type of unformatted output file:
   (IFORMO)                            Default: 1    ! IFORMO =  1  !

        1 = CALPUFF/CALGRID type file (CALMET.DAT)
        2 = MESOPUFF-II type file     (PACOUT.DAT)


LINE PRINTER OUTPUT OPTIONS:

   Print met. fields ?  (LPRINT)       Default: F     ! LPRINT = F !
   (F = Do not print, T = Print)
   (NOTE: parameters below control which
          met. variables are printed)

   Print interval
   (IPRINF) in hours                   Default: 1     ! IPRINF =  24  !
   (Meteorological fields are printed
    every  24  hours)


   Specify which layers of U, V wind component
   to print (IUVOUT(NZ)) -- NOTE: NZ values must be entered
   (0=Do not print, 1=Print)
   (used only if LPRINT=T)        Defaults: NZ*0
   ! IUVOUT =   0 ,  0 ,  0 ,  1 ,  0 ,  0 ,  0 ,  0 ,  0 ,  0  !
   -----------------------


   Specify which levels of the W wind component to print
   (NOTE: W defined at TOP cell face --  6  values)
   (IWOUT(NZ)) -- NOTE: NZ values must be entered
   (0=Do not print, 1=Print)
   (used only if LPRINT=T & LCALGRD=T)
   -----------------------------------
                                        Defaults: NZ*0
    ! IWOUT =  0 ,  0 ,  0 ,  1 ,  0 ,  0 ,  0 ,  0 ,  0 ,  0  !


   Specify which levels of the 3-D temperature field to print
   (ITOUT(NZ)) -- NOTE: NZ values must be entered
   (0=Do not print, 1=Print)
   (used only if LPRINT=T & LCALGRD=T)
   -----------------------------------
                                        Defaults: NZ*0
    ! ITOUT =   0 ,  0 ,  0 ,  1 ,  0 ,  0 ,  0 ,  0 ,  0 ,  0  !

   Specify which meteorological fields
   to print
   (used only if LPRINT=T)             Defaults: 0 (all variables)
   -----------------------


     Variable            Print ?
                     (0 = do not print,
                      1 = print)
     --------        ------------------

  !  STABILITY  =          1            ! - PGT stability class
  !  USTAR      =          1            ! - Friction velocity
  !  MONIN      =          1            ! - Monin-Obukhov length
  !  MIXHT      =          1            ! - Mixing height
```

```
!  WSTAR      =          1           ! - Convective velocity scale
!  PRECIP     =          1           ! - Precipitation rate
!  SENSHEAT   =          1           ! - Sensible heat flux
!  CONVZI     =          1           ! - Convective mixing ht.


 Testing and debug print options for micrometeorological module

    Print input meteorological data and
    internal variables (LDB)         Default: F       ! LDB = F !
    (F = Do not print, T = print)
    (NOTE: this option produces large amounts of output)

    First time step for which debug data
    are printed (NN1)                Default: 1       ! NN1 =  1  !

    Last time step for which debug data
    are printed (NN2)                Default: 1       ! NN2 =  1  !


 Testing and debug print options for wind field module
 (all of the following print options control output to
  wind field module's output files: TEST.PRT, TEST.OUT,
  TEST.KIN, TEST.FRD, and TEST.SLP)

    Control variable for writing the test/debug
    wind fields to disk files (IOUTD)
    (0=Do not write, 1=write)        Default: 0       ! IOUTD =  0  !

    Number of levels, starting at the surface,
    to print (NZPRN2)                Default: 1       ! NZPRN2 =  0  !

    Print the INTERPOLATED wind components ?
    (IPR0) (0=no, 1=yes)             Default: 0       !  IPR0 =  0  !

    Print the TERRAIN ADJUSTED surface wind
    components ?
    (IPR1) (0=no, 1=yes)             Default: 0       !  IPR1 =  0  !

    Print the SMOOTHED wind components and
    the INITIAL DIVERGENCE fields ?
    (IPR2) (0=no, 1=yes)             Default: 0       !  IPR2 =  0  !

    Print the FINAL wind speed and direction
    fields ?
    (IPR3) (0=no, 1=yes)             Default: 0       !  IPR3 =  0  !

    Print the FINAL DIVERGENCE fields ?
    (IPR4) (0=no, 1=yes)             Default: 0       !  IPR4 =  0  !

    Print the winds after KINEMATIC effects
    are added ?
    (IPR5) (0=no, 1=yes)             Default: 0       !  IPR5 =  0  !

    Print the winds after the FROUDE NUMBER
    adjustment is made ?
    (IPR6) (0=no, 1=yes)             Default: 0       !  IPR6 =  0  !

    Print the winds after SLOPE FLOWS
    are added ?
    (IPR7) (0=no, 1=yes)             Default: 0       !  IPR7 =  0  !

    Print the FINAL wind field components ?
```

```
          (IPR8) (0=no, 1=yes)             Default: 0       !  IPR8 =  0  !

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 4 -- Meteorological data options
--------------


    NUMBER OF SURFACE & PRECIP. METEOROLOGICAL STATIONS

       Number of surface stations   (NSSTA)  No default     ! NSSTA =  6  !
       Number of precipitation stations
                                    (NPSTA)  No default     ! NPSTA =  14  !

    CLOUD DATA OPTIONS
       Griddid cloud fields:
                                   (ICLOUD)  Default: 0     ! ICLOUD =  0  !
       ICLOUD = 0 - Gridded clouds not used
       ICLOUD = 1 - Gridded CLOUD.DAT generated as OUTPUT
       ICLOUD = 2 - Gridded CLOUD.DAT read as INPUT

    FILE FORMATS

       Surface meteorological data file format
                                   (IFORMS)  Default: 2     ! IFORMS =  2  !
       (1 = unformatted (e.g., SMERGE output))
       (2 = formatted   (free-formatted user input))

       Precipitation data file format
                                   (IFORMP)  Default: 2     ! IFORMP =  2  !
       (1 = unformatted (e.g., PMERGE output))
       (2 = formatted   (free-formatted user input))

       Cloud data file format
                                   (IFORMC)  Default: 2     ! IFORMC =  1  !
       (1 = unformatted - CALMET unformatted output)
       (2 = formatted   - free-formatted CALMET output or user input)

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 5 -- Wind Field Options and Parameters
--------------


    WIND FIELD MODEL OPTIONS
       Model selection variable (IWFCOD)     Default: 1      ! IWFCOD =  1  !
          0 = Objective analysis only
          1 = Diagnostic wind module

       Compute Froude number adjustment
       effects ? (IFRADJ)                    Default: 1      ! IFRADJ =  1  !
       (0 = NO, 1 = YES)

       Compute kinematic effects ? (IKINE)   Default: 0      ! IKINE  =  0  !
       (0 = NO, 1 = YES)

       Use O'Brien procedure for adjustment
```

```
     of the vertical velocity ? (IOBR)     Default: 0      ! IOBR =  0  !
     (0 = NO, 1 = YES)

     Compute slope flow effects ? (ISLOPE) Default: 1      ! ISLOPE  =  1  !
     (0 = NO, 1 = YES)

     Extrapolate surface wind observations
     to upper layers ? (IEXTRP)            Default: -4     ! IEXTRP = -4  !
     (1 = no extrapolation is done,
      2 = power law extrapolation used,
      3 = user input multiplicative factors
          for layers 2 - NZ used (see FEXTRP array)
      4 = similarity theory used
      -1, -2, -3, -4 = same as above except layer 1 data
          at upper air stations are ignored

     Extrapolate surface winds even
     if calm? (ICALM)                      Default: 0      ! ICALM  =  0  !
     (0 = NO, 1 = YES)

     Layer-dependent biases modifying the weights of
     surface and upper air stations (BIAS(NZ))
       -1<=BIAS<=1
     Negative BIAS reduces the weight of upper air stations
       (e.g. BIAS=-0.1 reduces the weight of upper air stations
     by 10%; BIAS= -1, reduces their weight by 100 %)
     Positive BIAS reduces the weight of surface stations
       (e.g. BIAS= 0.2 reduces the weight of surface stations
     by 20%; BIAS=1 reduces their weight by 100%)
     Zero BIAS leaves weights unchanged (1/R**2 interpolation)
     Default: NZ*0
                              ! BIAS =  0 ,  0 ,  0 , 0 , 0 ,  0 ,  0 ,  0 ,  0 ,
0  !

     Minimum distance from nearest upper air station
     to surface station for which extrapolation
     of surface winds at surface station will be allowed
     (RMIN2: Set to -1 for IEXTRP = 4 or other situations
      where all surface stations should be extrapolated)
                                            Default: 4.    ! RMIN2 = -1.0 !

     Use gridded prognostic wind field model
     output fields as input to the diagnostic
     wind field model (IPROG)              Default: 0      ! IPROG =  0  !
     (0 = No, [IWFCOD = 0 or 1]
      1 = Yes, use CSUMM prog. winds as Step 1 field, [IWFCOD = 0]
      2 = Yes, use CSUMM prog. winds as initial guess field [IWFCOD = 1]
      3 = Yes, use winds from MM4.DAT file as Step 1 field [IWFCOD = 0]
      4 = Yes, use winds from MM4.DAT file as initial guess field [IWFCOD = 1]
      5 = Yes, use winds from MM4.DAT file as observations [IWFCOD = 1]
      13 = Yes, use winds from MM5.DAT file as Step 1 field [IWFCOD = 0]
      14 = Yes, use winds from MM5.DAT file as initial guess field [IWFCOD = 1]
      15 = Yes, use winds from MM5.DAT file as observations [IWFCOD = 1]

  RADIUS OF INFLUENCE PARAMETERS

     Use varying radius of influence       Default: F      ! LVARY =  F!
     (if no stations are found within RMAX1,RMAX2,
      or RMAX3, then the closest station will be used)

     Maximum radius of influence over land
     in the surface layer (RMAX1)          No default      ! RMAX1 = 30. !
                                           Units: km
```

```
     Maximum radius of influence over land
     aloft (RMAX2)                          No default      ! RMAX2 = 50. !
                                            Units: km
     Maximum radius of influence over water
     (RMAX3)                                No default      ! RMAX3 = 500. !
                                            Units: km


  OTHER WIND FIELD INPUT PARAMETERS

     Minimum radius of influence used in
     the wind field interpolation (RMIN)    Default: 0.1    ! RMIN = 1.0 !
                                            Units: km
     Radius of influence of terrain
     features (TERRAD)                      No default      ! TERRAD = 10. !

                                            Units: km
     Relative weighting of the first
     guess field and observations in the
     SURFACE layer (R1)                     No default      ! R1 = 10. !
     (R1 is the distance from an            Units: km
     observational station at which the
     observation and first guess field are
     equally weighted)

     Relative weighting of the first
     guess field and observations in the
     layers ALOFT (R2)                      No default      ! R2 = 25. !
     (R2 is applied in the upper layers     Units: km
     in the same manner as R1 is used in
     the surface layer).

     Relative weighting parameter of the
     prognostic wind field data (RPROG)     No default      ! RPROG = 54. !
     (Used only if IPROG = 1)               Units: km
     ------------------------

     Maximum acceptable divergence in the
     divergence minimization procedure
     (DIVLIM)                               Default: 5.E-6  ! DIVLIM= 5.0E-06 !

     Maximum number of iterations in the
     divergence min. procedure (NITER)      Default: 50     ! NITER =  50  !

     Number of passes in the smoothing
     procedure (NSMTH(NZ))
     NOTE: NZ values must be entered
          Default: 2,(mxnz-1)*4 ! NSMTH =
2 ,  4 ,  4 ,  4 ,  4 ,  4 ,  4 ,  4 ,  4 ,  4   !

     Maximum number of stations used in
     each layer for the interpolation of
     data to a grid point (NINTR2(NZ))
     NOTE: NZ values must be entered        Default: 99.    ! NINTR2 =
99 ,  99 ,  99 ,  99 ,  99 ,  99,  99 ,  99 ,  99 ,  99  !

     Critical Froude number (CRITFN)        Default: 1.0    ! CRITFN = 1. !

     Empirical factor controlling the
     influence of kinematic effects
     (ALPHA)                                Default: 0.1    ! ALPHA = 0.1 !

     Multiplicative scaling factor for
```

```
   extrapolation of surface observations
   to upper layers (FEXTR2(NZ))         Default: NZ*0.0
   ! FEXTR2 = 0., 0., 0., 0., 0., 0., 0., 0., 0., 0. !
   (Used only if IEXTRP = 3 or -3)


BARRIER INFORMATION

   Number of barriers to interpolation
   of the wind fields (NBAR)            Default: 0      ! NBAR =  0  !

   THE FOLLOWING 4 VARIABLES ARE INCLUDED
   ONLY IF NBAR > 0
   NOTE: NBAR values must be entered     No defaults
         for each variable               Units: km

      X coordinate of BEGINNING
      of each barrier (XBBAR(NBAR))      ! XBBAR = 0. !
      Y coordinate of BEGINNING
      of each barrier (YBBAR(NBAR))      ! YBBAR = 0. !

      X coordinate of ENDING
      of each barrier (XEBAR(NBAR))      ! XEBAR = 0. !
      Y coordinate of ENDING
      of each barrier (YEBAR(NBAR))      ! YEBAR = 0. !


DIAGNOSTIC MODULE DATA INPUT OPTIONS

   Surface temperature (IDIOPT1)         Default: 0      ! IDIOPT1 =  0  !
      0 = Compute internally from
          hourly surface observations
      1 = Read preprocessed values from
          a data file (DIAG.DAT)

      Surface met. station to use for
      the surface temperature (ISURFT)   No default     ! ISURFT =  4  !
      (Must be a value from 1 to NSSTA)
      (Used only if IDIOPT1 = 0)
      --------------------------

   Domain-averaged temperature lapse
   rate (IDIOPT2)                        Default: 0     ! IDIOPT2 =  0  !
      0 = Compute internally from
          twice-daily upper air observations
      1 = Read hourly preprocessed values
          from a data file (DIAG.DAT)

      Upper air station to use for
      the domain-scale lapse rate (IUPT) No default     ! IUPT   =  2  !
      (Must be a value from 1 to NUSTA)
      (Used only if IDIOPT2 = 0)
      --------------------------

      Depth through which the domain-scale
      lapse rate is computed (ZUPT)      Default: 200.  ! ZUPT = 200. !
      (Used only if IDIOPT2 = 0)         Units: meters
      --------------------------

   Domain-averaged wind components
   (IDIOPT3)                             Default: 0     ! IDIOPT3 =  0  !
      0 = Compute internally from
          twice-daily upper air observations
```

```
   1 = Read hourly preprocessed values
       a data file (DIAG.DAT)

   Upper air station to use for
   the domain-scale winds (IUPWND)    Default: -1    ! IUPWND = -1  !
   (Must be a value from -1 to NUSTA)
   (Used only if IDIOPT3 = 0)
   --------------------------

   Bottom and top of layer through
   which the domain-scale winds
   are computed
   (ZUPWND(1), ZUPWND(2))        Defaults: 1., 1000. ! ZUPWND= 1., 1000. !
   (Used only if IDIOPT3 = 0)    Units: meters
   --------------------------

Observed surface wind components
for wind field module (IDIOPT4)  Default: 0     ! IDIOPT4 =  0  !
   0 = Read WS, WD from a surface
       data file (SURF.DAT)
   1 = Read hourly preprocessed U, V from
       a data file (DIAG.DAT)

Observed upper air wind components
for wind field module (IDIOPT5)  Default: 0     ! IDIOPT5 =  0  !
   0 = Read WS, WD from an upper
       air data file (UP1.DAT, UP2.DAT, etc.)
   1 = Read hourly preprocessed U, V from
       a data file (DIAG.DAT)

LAKE BREEZE INFORMATION

   Use Lake Breeze Module  (LLBREZE)
                                  Default: F      ! LLBREZE = F !

    Number of lake breeze regions (NBOX)          ! NBOX =  0  !

 X Grid line 1 defining the region of interest
                                               ! XG1 = 0. !
 X Grid line 2 defining the region of interest
                                               ! XG2 = 0. !
 Y Grid line 1 defining the region of interest
                                               ! YG1 = 0. !
 Y Grid line 2 defining the region of interest
                                               ! YG2 = 0. !

  X Point defining the coastline (Straight line)
            (XBCST)  (KM)   Default: none    ! XBCST = 0. !

  Y Point defining the coastline (Straight line)
            (YBCST)  (KM)   Default: none    ! YBCST = 0. !

  X Point defining the coastline (Straight line)
            (XECST)  (KM)   Default: none    ! XECST = 0. !

  Y Point defining the coastline (Straight line)
            (YECST)  (KM)   Default: none    ! YECST = 0. !


Number of stations in the region     Default: none ! NLB = *1 !*
(Surface stations + upper air stations)

Station ID's  in the region   (METBXID(NLB))
```

```
       (Surface stations first, then upper air stations)
         ! METBXID = *0 !*

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 6 -- Mixing Height, Temperature and Precipitation Parameters
--------------

    EMPIRICAL MIXING HEIGHT CONSTANTS

       Neutral, mechanical equation
       (CONSTB)                            Default: 1.41   ! CONSTB = 1.41 !
       Convective mixing ht. equation
       (CONSTE)                            Default: 0.15   ! CONSTE = 0.15 !
       Stable mixing ht. equation
       (CONSTN)                            Default: 2400.  ! CONSTN = 2400.!
       Overwater mixing ht. equation
       (CONSTW)                            Default: 0.16   ! CONSTW = 0.16 !
       Absolute value of Coriolis
       parameter (FCORIOL)                 Default: 1.E-4  ! FCORIOL = 1.0E-04!
                                           Units: (1/s)

    SPATIAL AVERAGING OF MIXING HEIGHTS

       Conduct spatial averaging
       (IAVEZI)  (0=no, 1=yes)             Default: 1      ! IAVEZI =  1  !

       Max. search radius in averaging
       process (MNMDAV)                    Default: 1      ! MNMDAV =  10  !
                                           Units: Grid
                                                  cells
       Half-angle of upwind looking cone
       for averaging (HAFANG)              Default: 30.    ! HAFANG = 30. !
                                           Units: deg.
       Layer of winds used in upwind
       averaging (ILEVZI)                  Default: 1      ! ILEVZI =  1  !
       (must be between 1 and NZ)

    OTHER MIXING HEIGHT VARIABLES

       Minimum potential temperature lapse
       rate in the stable layer above the
       current convective mixing ht.       Default: 0.001  ! DPTMIN = 0.001 !
       (DPTMIN)                            Units: deg. K/m
       Depth of layer above current conv.
       mixing height through which lapse   Default: 200.   ! DZZI = 200. !
       rate is computed (DZZI)             Units: meters

       Minimum overland mixing height      Default:  50.   ! ZIMIN = 50. !
       (ZIMIN)                             Units: meters
       Maximum overland mixing height      Default: 3000.  ! ZIMAX = 3000. !
       (ZIMAX)                             Units: meters
       Minimum overwater mixing height     Default:   50.  ! ZIMINW = 50. !
       (ZIMINW) -- (Not used if observed   Units: meters
       overwater mixing hts. are used)
       Maximum overwater mixing height     Default: 3000.  ! ZIMAXW = 3000. !
       (ZIMAXW) -- (Not used if observed   Units: meters
       overwater mixing hts. are used)
```

```
    TEMPERATURE PARAMETERS

       Interpolation type
       (1 = 1/R ; 2 = 1/R**2)                Default:1          ! IRAD =  1  !

       Radius of influence for temperature
       interpolation (TRADKM)                Default: 500.      ! TRADKM = 100. !
                                             Units: km

       Maximum Number of stations to include
       in temperature interpolation (NUMTS)  Default: 5         ! NUMTS = 5  !

       Conduct spatial averaging of temp-
       eratures (IAVET)  (0=no, 1=yes)         Default: 1     ! IAVET =  1  !
       (will use mixing ht MNMDAV,HAFANG
        so make sure they are correct)

       Default temperature gradient        Default: -.0098 ! TGDEFB = -0.0098 !
       below the mixing height over
       water (K/m) (TGDEFB)

       Default temperature gradient        Default: -.0045 ! TGDEFA = -0.0045 !
       above the mixing height over
       water (K/m) (TGDEFA)

       Beginning (JWAT1) and ending (JWAT2)
       land use categories for temperature                    ! JWAT1 =  999  !
       interpolation over water -- Make                       ! JWAT2 =  999  !
       bigger than largest land use to disable

   PRECIP INTERPOLATION PARAMETERS

       Method of interpolation (NFLAGP)      Default = 2    ! NFLAGP =  2  !
        (1=1/R,2=1/R**2,3=EXP/R**2)
       Radius of Influence (km) (SIGMAP)     Default = 100.0  ! SIGMAP = 50. !
        (0.0 => use half dist. btwn
         nearest stns w & w/out
         precip when NFLAGP = 3)
       Minimum Precip. Rate Cutoff (mm/hr)   Default = 0.01  ! CUTP = 0.01 !
        (values < CUTP = 0.0 mm/hr)
!END!


-------------------------------------------------------------------------------

INPUT GROUP: 7 -- Surface meteorological station parameters
--------------

     SURFACE STATION VARIABLES
     (One record per station --  6  records in all)


             1     2
         Name   ID            X coord.   Y coord.   Time   Anem.
                               (km)       (km)      zone   Ht.(m)
       ----------------------------------------------------------
! SS1  ='GRB '   14898       887.021     4936.896    6    9.1  !
! SS2  ='DLH '   14913       559.739     5186.731    6    6.4  !
! SS3  ='FAR '   14914       209.459     5204.611    6    8.5  !
! SS4  ='INL '   14918       470.490     5379.135    6    6.1  !
! SS5  ='MSP '   14922       481.572     4969.823    6    10  !
! SS6  ='EAC '   14991       356.736      657.833    6    10  !
-------------------
```

```
      1
        Four character string for station name
        (MUST START IN COLUMN 9)

      2
        Five digit integer for station ID

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 8 -- Upper air meteorological station parameters
--------------

     UPPER AIR STATION VARIABLES
     (One record per station --  3  records in all)

             1     2
         Name    ID      X coord.   Y coord.  Time zone
                           (km)       (km)
        ----------------------------------------------
! US1  ='STC '   14926    418.037   5044.388    6  !
! US2  ='INL '   14918    470.490   5379.135    6  !
! US3  ='GRB '   14898    887.021   4936.896    6  !
-------------------
      1
        Four character string for station name
        (MUST START IN COLUMN 9)

      2
        Five digit integer for station ID

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 9 -- Precipitation station parameters
--------------

     PRECIPITATION STATION VARIABLES
     (One record per station --  14  records in all)
     (NOT INCLUDED IF NPSTA = 0)

            1           2
         Name   Station    X coord.  Y coord.
                 Code       (km)      (km)
         ------------------------------------

! PS1  ='BGF '   210746    440.554   5338.615     !
! PS2  ='CLM '   211589    394.499   5393.014     !
! PS3  ='DLH '   212248    559.739   5186.731     !
! PS4  ='GFL '   213417    657.437   5334.911     !
! PS5  ='HLO '   213863    547.348   5145.878     !
! PS6  ='INL '   214026    470.490   5379.135     !
! PS7  ='ORR '   216213    511.179   5321.646     !
! PS8  ='PGD '   216612    455.858   5232.897     !
! PS9  ='SLD '   217460    475.835   5182.778     !
! PS10 ='TFT '   218280    661.721   5270.157     !
! PS11 ='WLS '   218613    598.373   5233.551     !
! PS12 ='WKR '   218621    381.114   5217.253     !
! PS13 ='WBG '   219059    419.563   5253.656     !
```

```
! PS14 ='WNT '   219101    592.120   5309.405     !
-------------------
```

1
Four character string for station name
(MUST START IN COLUMN 9)

2
Six digit station code composed of state
code (first 2 digits) and station ID (last
4 digits)

!END!

ATTACHMENT U

CALPUFF Input File (One of Six Files)

```
MPCA Taconite BART Study  - Pre-BART Emissions
Boundary Waters C. A. Wilderness (1-500)
CALMET data - 12/1/84 through 11/30/85
---------------- Run title (3 lines) ------------------------------------------

                    CALPUFF MODEL CONTROL FILE
                    --------------------------

-------------------------------------------------------------------------------

INPUT GROUP: 0 -- Input and Output File Names

--------------
Default Name  Type          File Name
------------  ----          ---------
CALMET.DAT    input    * METDAT =            *
    or
ISCMET.DAT    input    * ISCDAT =            *
    or
PLMMET.DAT    input    * PLMDAT =            *
    or
PROFILE.DAT   input    * PRFDAT =            *
SURFACE.DAT   input    * SFCDAT =            *
RESTARTB.DAT  input    * RSTARTB=            *
--------------------------------------------------------------------------------
CALPUFF.LST   output   ! PUFLST =L:\CALPUFF\BART\OUTPUT\P85PREA.LST  !
CONC.DAT      output   ! CONDAT =L:\CALPUFF\BART\OUTPUT\P85PREA.CON     !
DFLX.DAT      output   ! DFDAT  =L:\CALPUFF\BART\OUTPUT\P85PREA.DRY     !
WFLX.DAT      output   ! WFDAT  =L:\CALPUFF\BART\OUTPUT\P85PREA.WET     !

VISB.DAT      output   ! VISDAT =L:\CALPUFF\BART\OUTPUT\P85PREA.VIS     !
RESTARTE.DAT  output   * RSTARTE=            *
--------------------------------------------------------------------------------
Emission Files
--------------
PTEMARB.DAT   input    * PTDAT  =            *
VOLEMARB.DAT  input    * VOLDAT =            *
BAEMARB.DAT   input    * ARDAT  =            *
LNEMARB.DAT   input    * LNDAT  =            *
--------------------------------------------------------------------------------
Other Files
-----------
OZONE.DAT     input    * OZDAT  =            *
VD.DAT        input    * VDDAT  =            *
CHEM.DAT      input    * CHEMDAT=            *
HILL.DAT      input    * HILDAT=            *
HILLRCT.DAT   input    * RCTDAT=            *
COASTLN.DAT   input    * CSTDAT=            *
FLUXBDY.DAT   input    * BDYDAT=            *
BCON.DAT      input    * BCNDAT=            *
DEBUG.DAT     output   * DEBUG =            *
MASSFLX.DAT   output   * FLXDAT=            *
MASSBAL.DAT   output   * BALDAT=            *
FOG.DAT       output   * FOGDAT=            *
--------------------------------------------------------------------------------
All file names will be converted to lower case if LCFILES = T
Otherwise, if LCFILES = F, file names will be converted to UPPER CASE
         T = lower case      ! LCFILES = F !
         F = UPPER CASE
NOTE: (1) file/path names can be up to 70 characters in length


Provision for multiple input files
```

```
----------------------------------

     Number of CALMET.DAT files for run (NMETDAT)
                                    Default: 1       ! NMETDAT =   4   !

     Number of PTEMARB.DAT files for run (NPTDAT)
                                    Default: 0       ! NPTDAT =  0  !

     Number of BAEMARB.DAT files for run (NARDAT)
                                    Default: 0       ! NARDAT =  0  !

     Number of VOLEMARB.DAT files for run (NVOLDAT)
                                    Default: 0       ! NVOLDAT =  0  !

!END!

-------------
Subgroup (0a)
-------------

  The following CALMET.DAT filenames are processed in sequence if NMETDAT>1

Default Name  Type          File Name
------------  ----          ---------
 none         input    ! METDAT=L:\CALMET\OUTPUTB2\METQ01.DAT     !  !END!
 none         input    ! METDAT=L:\CALMET\OUTPUTB2\METQ02.DAT     !  !END!
 none         input    ! METDAT=L:\CALMET\OUTPUTB2\METQ03.DAT     !  !END!
 none         input    ! METDAT=L:\CALMET\OUTPUTB2\METQ04.DAT     !  !END!


--------------------------------------------------------------------------------

INPUT GROUP: 1 -- General run control parameters
--------------

    Option to run all periods found
    in the met. file     (METRUN)   Default: 0       ! METRUN =   0  !

         METRUN = 0 - Run period explicitly defined below
         METRUN = 1 - Run all periods in met. file

     Starting date:   Year (IBYR) -- No default       ! IBYR =  1984  !
     (used only if   Month (IBMO) -- No default       ! IBMO =  12  !
      METRUN = 0)      Day (IBDY) -- No default       ! IBDY =  1  !
                      Hour (IBHR) -- No default       ! IBHR =  1  !

     Length of run (hours) (IRLG) -- No default       ! IRLG =  8760  !

     Number of chemical species (NSPEC)
                                    Default: 5       ! NSPEC =  6   !

     Number of chemical species
     to be emitted  (NSE)           Default: 3       ! NSE =  3   !

     Flag to stop run after
     SETUP phase (ITEST)            Default: 2       ! ITEST =  2   !
     (Used to allow checking
     of the model inputs, files, etc.)
           ITEST = 1 - STOPS program after SETUP phase
           ITEST = 2 - Continues with execution of program
                       after SETUP

     Restart Configuration:
```

```
   Control flag (MRESTART)      Default: 0       ! MRESTART =  0   !

      0 = Do not read or write a restart file
      1 = Read a restart file at the beginning of
          the run
      2 = Write a restart file during run
      3 = Read a restart file at beginning of run
          and write a restart file during run

   Number of periods in Restart
   output cycle (NRESPD)        Default: 0       ! NRESPD =  0   !

      0 = File written only at last period
     >0 = File updated every NRESPD periods

Meteorological Data Format (METFM)
                                Default: 1       ! METFM =  1   !

      METFM = 1 - CALMET binary file (CALMET.MET)
      METFM = 2 - ISC ASCII file (ISCMET.MET)
      METFM = 3 - AUSPLUME ASCII file (PLMMET.MET)
      METFM = 4 - CTDM plus tower file (PROFILE.DAT) and
                  surface parameters file (SURFACE.DAT)

PG sigma-y is adjusted by the factor (AVET/PGTIME)**0.2
Averaging Time (minutes) (AVET)
                                Default: 60.0    ! AVET = 60. !
PG Averaging Time (minutes) (PGTIME)
                                Default: 60.0    ! PGTIME = 60. !


!END!


--------------------------------------------------------------------------------

INPUT GROUP: 2 -- Technical options
--------------


     Vertical distribution used in the
     near field (MGAUSS)                  Default: 1     ! MGAUSS =  1   !
        0 = uniform
        1 = Gaussian

     Terrain adjustment method
     (MCTADJ)                             Default: 3     ! MCTADJ =  3   !
        0 = no adjustment
        1 = ISC-type of terrain adjustment
        2 = simple, CALPUFF-type of terrain
            adjustment
        3 = partial plume path adjustment

     Subgrid-scale complex terrain
     flag (MCTSG)                         Default: 0     ! MCTSG =  0   !
        0 = not modeled
        1 = modeled

     Near-field puffs modeled as
     elongated 0 (MSLUG)                  Default: 0     ! MSLUG =  0   !
        0 = no
        1 = yes (slug model used)
```

```
Transitional plume rise modeled ?
(MTRANS)                              Default: 1     ! MTRANS =  1   !
   0 = no  (i.e., final rise only)
   1 = yes (i.e., transitional rise computed)

Stack tip downwash? (MTIP)            Default: 1     ! MTIP =  1  !
   0 = no  (i.e., no stack tip downwash)
   1 = yes (i.e., use stack tip downwash)

Vertical wind shear modeled above
stack top? (MSHEAR)                   Default: 0     ! MSHEAR =  0  !
   0 = no  (i.e., vertical wind shear not modeled)
   1 = yes (i.e., vertical wind shear modeled)

Puff splitting allowed? (MSPLIT)      Default: 0     ! MSPLIT =  0  !
   0 = no (i.e., puffs not split)
   1 = yes (i.e., puffs are split)

Chemical mechanism flag (MCHEM)       Default: 1     ! MCHEM =  1   !
   0 = chemical transformation not
       modeled
   1 = transformation rates computed
       internally (MESOPUFF II scheme)
   2 = user-specified transformation
       rates used
   3 = transformation rates computed
       internally (RIVAD/ARM3 scheme)
   4 = secondary organic aerosol formation
       computed (MESOPUFF II scheme for OH)

Wet removal modeled ? (MWET)          Default: 1     ! MWET =  1   !
   0 = no
   1 = yes

Dry deposition modeled ? (MDRY)       Default: 1     ! MDRY =  1   !
   0 = no
   1 = yes
   (dry deposition method specified
    for each species in Input Group 3)

Method used to compute dispersion
coefficients (MDISP)                  Default: 3     ! MDISP =  3   !

   1 = dispersion coefficients computed from measured values
       of turbulence, sigma v, sigma w
   2 = dispersion coefficients from internally calculated
       sigma v, sigma w using micrometeorological variables
       (u*, w*, L, etc.)
   3 = PG dispersion coefficients for RURAL areas (computed using
       the ISCST multi-segment approximation) and MP coefficients in
       urban areas
   4 = same as 3 except PG coefficients computed using
       the MESOPUFF II eqns.
   5 = CTDM sigmas used for stable and neutral conditions.
       For unstable conditions, sigmas are computed as in
       MDISP = 3, described above.  MDISP = 5 assumes that
       measured values are read

Sigma-v/sigma-theta, sigma-w measurements used? (MTURBVW)
(Used only if MDISP = 1 or 5)         Default: 3     ! MTURBVW =  3  !
   1 = use sigma-v or sigma-theta measurements
       from PROFILE.DAT to compute sigma-y
```

```
        (valid for METFM = 1, 2, 3, 4)
    2 = use sigma-w measurements
        from PROFILE.DAT to compute sigma-z
        (valid for METFM = 1, 2, 3, 4)
    3 = use both sigma-(v/theta) and sigma-w
        from PROFILE.DAT to compute sigma-y and sigma-z
        (valid for METFM = 1, 2, 3, 4)
    4 = use sigma-theta measurements
        from PLMMET.DAT to compute sigma-y
        (valid only if METFM = 3)

Back-up method used to compute dispersion
when measured turbulence data are
missing (MDISP2)                      Default: 3     ! MDISP2 =  3  !
(used only if MDISP = 1 or 5)
    2 = dispersion coefficients from internally calculated
        sigma v, sigma w using micrometeorological variables
        (u*, w*, L, etc.)
    3 = PG dispersion coefficients for RURAL areas (computed using
        the ISCST multi-segment approximation) and MP coefficients in
        urban areas
    4 = same as 3 except PG coefficients computed using
        the MESOPUFF II eqns.

PG sigma-y,z adj. for roughness?      Default: 0     ! MROUGH =  0  !
(MROUGH)
    0 = no
    1 = yes

Partial plume penetration of          Default: 1     ! MPARTL =  1  !
elevated inversion?
(MPARTL)
    0 = no
    1 = yes

Strength of temperature inversion     Default: 0     ! MTINV =  0  !
provided in PROFILE.DAT extended records?
(MTINV)
    0 = no (computed from measured/default gradients)
    1 = yes

PDF used for dispersion under convective conditions?
                                      Default: 0     ! MPDF =  0  !
(MPDF)
    0 = no
    1 = yes

Sub-Grid TIBL module used for shore line?
                                      Default: 0     ! MSGTIBL = 0  !
(MSGTIBL)
    0 = no
    1 = yes

Boundary conditions (concentration) modeled?
                                      Default: 0     ! MBCON = 0  !
(MBCON)
    0 = no
    1 = yes


Analyses of fogging and icing impacts due to emissions from
arrays of mechanically-forced cooling towers can be performed
using CALPUFF in conjunction with a cooling tower emissions
```

```
     processor (CTEMISS) and its associated postprocessors.  Hourly
     emissions of water vapor and temperature from each cooling tower
     cell are computed for the current cell configuration and ambient
     conditions by CTEMISS. CALPUFF models the dispersion of these
     emissions and provides cloud information in a specialized format
     for further analysis. Output to FOG.DAT is provided in either
     'plume mode' or 'receptor mode' format.

     Configure for FOG Model output?
                                       Default: 0     ! MFOG =  0  !
     (MFOG)
        0 = no
        1 = yes  - report results in PLUME Mode format
        2 = yes  - report results in RECEPTOR Mode format


     Test options specified to see if
     they conform to regulatory
     values? (MREG)                    Default: 1     ! MREG =  0   !

        0 = NO checks are made
        1 = Technical options must conform to USEPA values
                      METFM    1
                      AVET     60. (min)
                      MGAUSS   1
                      MCTADJ   3
                      MTRANS   1
                      MTIP     1
                      MCHEM    1 (if modeling SOx, NOx)
                      MWET     1
                      MDRY     1
                      MDISP    3
                      MROUGH   0
                      MPARTL   1
                      SYTDEP   550. (m)
                      MHFTSZ   0

!END!


--------------------------------------------------------------------------------

INPUT GROUP: 3a, 3b -- Species list
-------------------

------------
Subgroup (3a)
------------

  The following species are modeled:

! CSPEC =          SO2 !         !END!
! CSPEC =          SO4 !         !END!
! CSPEC =          NOX !         !END!
! CSPEC =         HNO3 !         !END!
! CSPEC =          NO3 !         !END!
! CSPEC =          PMC !         !END!

                                                        Dry                OUTPUT
GROUP
    SPECIES          MODELED          EMITTED       DEPOSITED                NUMBER
     NAME         (0=NO, 1=YES)    (0=NO, 1=YES)    (0=NO,                  (0=NONE,
```

```
   (Limit: 12                                       1=COMPUTED-GAS        1=1st
CGRUP,
    Characters                                      2=COMPUTED-PARTICLE   2=2nd
CGRUP,
    in length)                                      3=USER-SPECIFIED)     3= etc.)

!          SO2  =          1,               1,           1,                  0   !
!          SO4  =          1,               0,           2,                  0   !
!          NOX  =          1,               1,           1,                  0   !
!         HNO3  =          1,               0,           1,                  0   !
!          NO3  =          1,               0,           2,                  0   !
!          PMC  =          1,               1,           2,                  0   !


!END!

-------------
Subgroup (3b)
-------------
  The following names are used for Species-Groups in which results
  for certain species are combined (added) prior to output.  The
  CGRUP name will be used as the species name in output files.
  Use this feature to model specific particle-size distributions
  by treating each size-range as a separate species.
  Order must be consistent with 3(a) above.

* CGRUP =         PM10 *     *END*


--------------------------------------------------------------------------------


INPUT GROUP: 4 -- Grid control parameters
--------------


METEOROLOGICAL grid:

            No. X grid cells (NX)      No default     ! NX =  50   !
            No. Y grid cells (NY)      No default     ! NY =  33   !
         No. vertical layers (NZ)      No default     ! NZ =  10   !

           Grid spacing (DGRIDKM)      No default     ! DGRIDKM = 6. !
                                       Units: km

                Cell face heights
                    (ZFACE(nz+1))      No defaults
                                       Units: m
   ! ZFACE = 0., 20., 50., 100., 200., 400., 800., 1200., 1600., 2000.,
              3600. !

            Reference Coordinates
           of SOUTHWEST corner of
                 grid cell(1, 1):

            X coordinate (XORIGKM)     No default     ! XORIGKM = 453.368 !
            Y coordinate (YORIGKM)       No default   ! YORIGKM = 5217.226 !
                                      Units: km

                 UTM zone (IUTMZN)     No default     ! IUTMZN =  15   !

   Reference coordinates of CENTER
        of the domain (used in the
```

```
    calculation of solar elevation
                           angles)

            Latitude  (deg.) (XLAT)    No default     ! XLAT  = 47.989  !
           Longitude (deg.) (XLONG)    No default     ! XLONG = 91.632  !
             Time zone        (XTZ)    No default     ! XTZ   = 6.0  !
       (PST=8, MST=7, CST=6, EST=5)


Computational grid:

     The computational grid is identical to or a subset of the MET. grid.
     The lower left (LL) corner of the computational grid is at grid point
     (IBCOMP, JBCOMP) of the MET. grid.  The upper right (UR) corner of the
     computational grid is at grid point (IECOMP, JECOMP) of the MET. grid.
     The grid spacing of the computational grid is the same as the MET. grid.

        X index of LL corner (IBCOMP)      No default     ! IBCOMP =  1   !
                  (1 <= IBCOMP <= NX)

        Y index of LL corner (JBCOMP)      No default     ! JBCOMP =  1   !
                  (1 <= JBCOMP <= NY)


        X index of UR corner (IECOMP)      No default     ! IECOMP =  50   !
                  (1 <= IECOMP <= NX)

        Y index of UR corner (JECOMP)      No default     ! JECOMP =  33   !
                  (1 <= JECOMP <= NY)



SAMPLING GRID (GRIDDED RECEPTORS):

     The lower left (LL) corner of the sampling grid is at grid point
     (IBSAMP, JBSAMP) of the MET. grid.  The upper right (UR) corner of the
     sampling grid is at grid point (IESAMP, JESAMP) of the MET. grid.
     The sampling grid must be identical to or a subset of the computational
     grid.  It may be a nested grid inside the computational grid.
     The grid spacing of the sampling grid is DGRIDKM/MESHDN.

        Logical flag indicating if gridded
        receptors are used (LSAMP)         Default: T     ! LSAMP = F !
        (T=yes, F=no)

        X index of LL corner (IBSAMP)      No default     ! IBSAMP =  1   !
         (IBCOMP <= IBSAMP <= IECOMP)

        Y index of LL corner (JBSAMP)      No default     ! JBSAMP =  1   !
         (JBCOMP <= JBSAMP <= JECOMP)


        X index of UR corner (IESAMP)      No default     ! IESAMP =  50   !
         (IBCOMP <= IESAMP <= IECOMP)

        Y index of UR corner (JESAMP)      No default     ! JESAMP =  33   !
         (JBCOMP <= JESAMP <= JECOMP)


       Nesting factor of the sampling
        grid (MESHDN)                      Default: 1     ! MESHDN =  1  !
        (MESHDN is an integer >= 1)
```

```
!END!

-------------------------------------------------------------------------------


INPUT GROUP: 5 -- Output Options
--------------
                                             *                           *
     FILE                       DEFAULT VALUE             VALUE THIS RUN
     ----                       -------------             --------------

   Concentrations (ICON)              1                   !  ICON =  1   !
   Dry Fluxes (IDRY)                  1                   !  IDRY =  1   !
   Wet Fluxes (IWET)                  1                   !  IWET =  1   !
   Relative Humidity (IVIS)           1                   !  IVIS =  1   !
    (relative humidity file is
     required for visibility
     analysis)
   Use data compression option in output file?
   (LCOMPRS)                           Default: T         ! LCOMPRS = T !

   *
    0 = Do not create file, 1 = create file


    DIAGNOSTIC MASS FLUX OUTPUT OPTIONS:

       Mass flux across specified boundaries
       for selected species reported hourly?
       (IMFLX)                         Default: 0         ! IMFLX =  0  !
         0 = no
         1 = yes (FLUXBDY.DAT and MASSFLX.DAT filenames
                  are specified in Input Group 0)

       Mass balance for each species
       reported hourly?
       (IMBAL)                         Default: 0         ! IMBAL =  0  !
         0 = no
         1 = yes (MASSBAL.DAT filename is
              specified in Input Group 0)


    LINE PRINTER OUTPUT OPTIONS:

       Print concentrations (ICPRT)    Default: 0         ! ICPRT =  0   !
       Print dry fluxes (IDPRT)        Default: 0         ! IDPRT =  0   !
       Print wet fluxes (IWPRT)        Default: 0         ! IWPRT =  0   !
       (0 = Do not print, 1 = Print)

       Concentration print interval
       (ICFRQ) in hours                Default: 1         ! ICFRQ =  1   !
       Dry flux print interval
       (IDFRQ) in hours                Default: 1         ! IDFRQ =  1   !
       Wet flux print interval
       (IWFRQ) in hours                Default: 1         ! IWFRQ =  1   !

       Units for Line Printer Output
       (IPRTU)                         Default: 1         ! IPRTU =  3   !
                       for            for
                  Concentration    Deposition
           1 =       g/m**3        g/m**2/s
```

```
          2 =      mg/m**3        mg/m**2/s
          3 =      ug/m**3        ug/m**2/s
          4 =      ng/m**3        ng/m**2/s
          5 =     Odour Units

        Messages tracking progress of run
        written to the screen ?
        (IMESG)                       Default: 2         ! IMESG =  2   !
          0 = no
          1 = yes (advection step, puff ID)
          2 = yes (YYYYJJJHH, # old puffs, # emitted puffs)


       SPECIES (or GROUP for combined species) LIST FOR OUTPUT OPTIONS

                 ---- CONCENTRATIONS ----   ------ DRY FLUXES ------   ------ WET
FLUXES ------   -- MASS FLUX --
   SPECIES
   /GROUP        PRINTED?  SAVED ON DISK?   PRINTED?  SAVED ON DISK?   PRINTED?
SAVED ON DISK?   SAVED ON DISK?
   -------       ------------------------   ------------------------
------------------------   ---------------
!          SO2 =     0,            1,            0,            1,            0,
 1,          0   !
!          SO4 =     0,            1,            0,            1,            0,
 1,          0   !
!          NOX =     0,            1,            0,            1,            0,
 0,          0   !
!         HNO3 =     0,            1,            0,            1,            0,
 1,          0   !
!          NO3 =     0,            1,            0,            1,            0,
 1,          0   !
!          PMC =     0,            1,            0,            1,            0,
 1,          0   !


       OPTIONS FOR PRINTING "DEBUG" QUANTITIES (much output)

         Logical for debug output
         (LDEBUG)                               Default: F     ! LDEBUG = F !

         First puff to track
         (IPFDEB)                               Default: 1     ! IPFDEB =  1  !

         Number of puffs to track
         (NPFDEB)                               Default: 1     ! NPFDEB =  1  !

         Met. period to start output
         (NN1)                                  Default: 1     ! NN1 =  1   !

         Met. period to end output
         (NN2)                                  Default: 10    ! NN2 =  10  !

!END!

-------------------------------------------------------------------------------


INPUT GROUP: 6a, 6b, & 6c -- Subgrid scale complex terrain inputs
-------------------------

---------------
```

```
Subgroup (6a)
---------------
       Number of terrain features (NHILL)       Default: 0     ! NHILL =  0   !

       Number of special complex terrain
       receptors  (NCTREC)                      Default: 0     ! NCTREC =  0   !

       Terrain and CTSG Receptor data for
       CTSG hills input in CTDM format ?
       (MHILL)                                  No Default     ! MHILL =  2   !
       1 = Hill and Receptor data created
           by CTDM processors & read from
           HILL.DAT and HILLRCT.DAT files
       2 = Hill data created by OPTHILL &
           input below in Subgroup (6b);
           Receptor data in Subgroup (6c)

       Factor to convert horizontal dimensions  Default: 1.0   ! XHILL2M = 0. !
       to meters (MHILL=1)

       Factor to convert vertical dimensions    Default: 1.0   ! ZHILL2M = 0. !
       to meters (MHILL=1)

       X-origin of CTDM system relative to      No Default     ! XCTDMKM = 0.0E00 !
       CALPUFF coordinate system, in Kilometers (MHILL=1)

       Y-origin of CTDM system relative to      No Default     ! YCTDMKM = 0.0E00 !
       CALPUFF coordinate system, in Kilometers (MHILL=1)

! END !

---------------
Subgroup (6b)
---------------

                      1 **
     HILL information


HILL           XC         YC        THETAH  ZGRID  RELIEF    EXPO 1    EXPO 2   SCALE
1    SCALE 2    AMAX1     AMAX2
 NO.          (km)       (km)       (deg.)   (m)     (m)       (m)       (m)       (m)
      (m)        (m)        (m)
----          ----       ----       ------  -----  ------    ------    ------
-------    -------    -----     -----

---------------
Subgroup (6c)
---------------

    COMPLEX TERRAIN RECEPTOR INFORMATION

                      XRCT         YRCT        ZRCT          XHH
                      (km)         (km)         (m)
                     ------        -----      ------         ----


-------------------
1
     Description of Complex Terrain Variables:
          XC, YC  = Coordinates of center of hill
          THETAH  = Orientation of major axis of hill (clockwise from
                    North)
```

```
        ZGRID    = Height of the  0  of the grid above mean sea
                   level
        RELIEF   = Height of the crest of the hill above the grid elevation
        EXPO 1   = Hill-shape exponent for the major axis
        EXPO 2   = Hill-shape exponent for the major axis
        SCALE 1 = Horizontal length scale along the major axis
        SCALE 2 = Horizontal length scale along the minor axis
        AMAX     = Maximum allowed axis length for the major axis
        BMAX     = Maximum allowed axis length for the major axis

        XRCT, YRCT = Coordinates of the complex terrain receptors
        ZRCT     = Height of the ground (MSL) at the complex terrain
                   Receptor
        XHH      = Hill number associated with each complex terrain receptor
                   (NOTE: MUST BE ENTERED AS A REAL NUMBER)

   **
     NOTE: DATA for each hill and CTSG receptor are treated as a separate
           input subgroup and therefore must end with an input group terminator.

-------------------------------------------------------------------------------


INPUT GROUP: 7 -- Chemical parameters for dry deposition of gases
--------------

      SPECIES     DIFFUSIVITY      ALPHA STAR      REACTIVITY    MESOPHYLL
RESISTANCE     HENRY'S LAW COEFFICIENT
       NAME        (cm**2/s)                                                (s/cm)
         (dimensionless)
      -------     -----------      ----------      ----------
--------------------     -----------------------

!          SO2 =     0.1509,         1000.,            8.,               0.,
         0.04 !
!          NOX =     0.1656,            1.,            8.,               5.,
          3.5 !
!         HNO3 =     0.1628,            1.,          180.,               0.,
   0.00000008 !

!END!


-------------------------------------------------------------------------------


INPUT GROUP: 8 -- Size parameters for dry deposition of particles
--------------

     For SINGLE SPECIES, the mean and standard deviation are used to
     compute a deposition velocity for NINT (see group 9) size-ranges,
     and these are then averaged to obtain a mean deposition velocity.

     For GROUPED SPECIES, the size distribution should be explicitly
     specified (by the 'species' in the group), and the standard deviation
     for each should be entered as 0.  The model will then use the
     deposition velocity for the stated mean diameter.

      SPECIES      GEOMETRIC MASS MEAN        GEOMETRIC STANDARD
       NAME             DIAMETER                   DEVIATION
                        (microns)                  (microns)
      -------      -------------------        ------------------
!          SO4 =          0.48,                      2.   !
```

```
!          NO3 =          0.48,                      2.   !
!          PMC =           6.2,                      0.   !

!END!

-------------------------------------------------------------------------------


INPUT GROUP: 9 -- Miscellaneous dry deposition parameters
--------------

     Reference cuticle resistance (s/cm)
     (RCUTR)                          Default: 30    !  RCUTR = 30.0 !
     Reference ground resistance  (s/cm)
     (RGR)                            Default: 10    !    RGR = 10.0 !
     Reference pollutant reactivity
     (REACTR)                         Default: 8     ! REACTR = 8.0 !

     Number of particle-size intervals used to
     evaluate effective particle deposition velocity
     (NINT)                           Default: 9     !   NINT =  9  !

     Vegetation state in unirrigated areas
     (IVEG)                           Default: 1     !   IVEG =  1   !
        IVEG=1 for active and unstressed vegetation
        IVEG=2 for active and stressed vegetation
        IVEG=3 for inactive vegetation

!END!

-------------------------------------------------------------------------------


INPUT GROUP: 10 -- Wet Deposition Parameters
---------------


                      Scavenging Coefficient -- Units: (sec)**(-1)

       Pollutant      Liquid Precip.       Frozen Precip.
       ---------      --------------       --------------
!          SO2 =         3.0E-05,             0.0E00 !
!          SO4 =         1.0E-04,            3.0E-05 !
!         HNO3 =         6.0E-05,             0.0E00 !
!          NO3 =         1.0E-04,            3.0E-05 !
!          PMC =         1.0E-04,            3.0E-05 !

!END!

-------------------------------------------------------------------------------


INPUT GROUP: 11 -- Chemistry Parameters
---------------

     Ozone data input option (MOZ)    Default: 1            ! MOZ =  0   !
     (Used only if MCHEM = 1, 3, or 4)
        0 = use a constant background ozone value
        1 = read hourly ozone concentrations from
            the OZONE.DAT data file
```

```
    Background ozone concentration
    (BCKO3) in ppb                    Default: 80.         ! BCKO3 = 40.0 !
    (Used only if MCHEM = 1, 3, or 4 and
     MOZ = 0 or (MOZ = 1 and all hourly
     O3 data missing)

    Background ammonia concentration
    (BCKNH3) in ppb                   Default: 10.         ! BCKNH3 = 1.0 !

    Nighttime SO2 loss rate (RNITE1)
    in percent/hour                   Default: 0.2         ! RNITE1 = .2 !

    Nighttime NOx loss rate (RNITE2)
    in percent/hour                   Default: 2.0         ! RNITE2 = 2.0 !

    Nighttime HNO3 formation rate (RNITE3)
    in percent/hour                   Default: 2.0         ! RNITE3 = 2.0 !

--- Data for SECONDARY ORGANIC AEROSOL (SOA) Option
    (used only if MCHEM = 4)

    The SOA module uses monthly values of:
         Fine particulate concentration in ug/m^3 (BCKPMF)
         Organic fraction of fine particulate     (OFRAC)
         VOC / NOX ratio (after reaction)         (VCNX)
    to characterize the air mass when computing
    the formation of SOA from VOC emissions.
    Typical values for several distinct air mass types are:

       Month    1    2    3    4    5    6    7    8    9   10   11   12
               Jan  Feb  Mar  Apr  May  Jun  Jul  Aug  Sep  Oct  Nov  Dec

    Clean Continental
       BCKPMF   1.   1.   1.   1.   1.   1.   1.   1.   1.   1.   1.   1.
       OFRAC  .15  .15  .20  .20  .20  .20  .20  .20  .20  .20  .20  .15
       VCNX    50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.

    Clean Marine (surface)
       BCKPMF  .5   .5   .5   .5   .5   .5   .5   .5   .5   .5   .5   .5
       OFRAC  .25  .25  .30  .30  .30  .30  .30  .30  .30  .30  .30  .25
       VCNX    50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.

    Urban - low biogenic (controls present)
       BCKPMF  30.  30.  30.  30.  30.  30.  30.  30.  30.  30.  30.  30.
       OFRAC  .20  .20  .25  .25  .25  .25  .25  .25  .20  .20  .20  .20
       VCNX     4.   4.   4.   4.   4.   4.   4.   4.   4.   4.   4.   4.

    Urban - high biogenic (controls present)
       BCKPMF  60.  60.  60.  60.  60.  60.  60.  60.  60.  60.  60.  60.
       OFRAC  .25  .25  .30  .30  .30  .55  .55  .55  .35  .35  .35  .25
       VCNX    15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.

    Regional Plume
       BCKPMF  20.  20.  20.  20.  20.  20.  20.  20.  20.  20.  20.  20.
       OFRAC  .20  .20  .25  .35  .25  .40  .40  .40  .30  .30  .30  .20
       VCNX    15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.

    Urban - no controls present
       BCKPMF 100. 100. 100. 100. 100. 100. 100. 100. 100. 100. 100. 100.
       OFRAC  .30  .30  .35  .35  .35  .55  .55  .55  .35  .35  .35  .30
       VCNX     2.   2.   2.   2.   2.   2.   2.   2.   2.   2.   2.   2.
```

```
     Default: Clean Continental
     !  BCKPMF = 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00,
1.00 !
     !  OFRAC  = 0.15, 0.15, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20,
0.15 !
     !  VCNX   = 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00,
50.00, 50.00, 50.00 !


!END!


-------------------------------------------------------------------------------


INPUT GROUP: 12 -- Misc. Dispersion and Computational Parameters
---------------

     Horizontal size of puff (m) beyond which
     time-dependent dispersion equations (Heffter)
     are used to determine sigma-y and
     sigma-z (SYTDEP)                           Default: 550.   ! SYTDEP = 5.5E02 !

     Switch for using Heffter equation for sigma z
     as above (0 = Not use Heffter; 1 = use Heffter
     (MHFTSZ)                                   Default: 0      ! MHFTSZ =  0   !

     Stability class used to determine plume
     growth rates for puffs above the boundary
     layer (JSUP)                               Default: 5      ! JSUP =  5   !

     Vertical dispersion constant for stable
     conditions (k1 in Eqn. 2.7-3)  (CONK1)     Default: 0.01   ! CONK1 = .01 !

     Vertical dispersion constant for neutral/
     unstable conditions (k2 in Eqn. 2.7-4)
     (CONK2)                                    Default: 0.1    ! CONK2 = .1 !

     Factor for determining Transition-point from
     Schulman-Scire to Huber-Snyder Building Downwash
     scheme (SS used for Hs < Hb + TBD * HL)
     (TBD)                                      Default: 0.5    ! TBD = .5 !
        TBD < 0   ==> always use Huber-Snyder
        TBD = 1.5 ==> always use Schulman-Scire
        TBD = 0.5 ==> ISC Transition-point

     Range of land use categories for which
     urban dispersion is assumed
     (IURB1, IURB2)                             Default: 10     ! IURB1 =  10  !
                                                         19     ! IURB2 =  19  !

     Site characterization parameters for single-point Met data files ---------
     (needed for METFM = 2,3,4)

        Land use category for modeling domain
        (ILANDUIN)                              Default: 20     ! ILANDUIN =  20  !

        Roughness length (m) for modeling domain
        (Z0IN)                                  Default: 0.25   ! Z0IN = .25 !

        Leaf area index for modeling domain
        (XLAIIN)                                Default: 3.0    ! XLAIIN = 3.0 !
```

```
   Elevation above sea level (m)
   (ELEVIN)                                Default: 0.0     ! ELEVIN = .0 !

   Latitude (degrees) for met location
   (XLATIN)                                Default: -999.   ! XLATIN = 47.25 !

   Longitude (degrees) for met location
   (XLONIN)                                Default: -999.   ! XLONIN = 91.25 !

Specialized information for interpreting single-point Met data files -----

   Anemometer height (m) (Used only if METFM = 2,3)
   (ANEMHT)                                Default: 10.     ! ANEMHT = 10.0 !

   Form of lateral turbulance data in PROFILE.DAT file
   (Used only if METFM = 4 or MTURBVW = 1 or 3)
   (ISIGMAV)                               Default: 1       ! ISIGMAV =  1  !
       0 = read sigma-theta
       1 = read sigma-v

   Choice of mixing heights (Used only if METFM = 4)
   (IMIXCTDM)                              Default: 0       ! IMIXCTDM =  0  !
       0 = read PREDICTED mixing heights
       1 = read OBSERVED mixing heights

Maximum length of a slug (met. grid units)
(XMXLEN)                                   Default: 1.0     ! XMXLEN = 1.0 !

Maximum travel distance of a puff/slug (in
grid units) during one sampling step
(XSAMLEN)                                  Default: 1.0     ! XSAMLEN = 1.0 !

Maximum Number of slugs/puffs release from
one source during one time step
(MXNEW)                                    Default: 99      ! MXNEW =  99   !

Maximum Number of sampling steps for
one puff/slug during one time step
(MXSAM)                                    Default: 99      ! MXSAM =  99   !

Number of iterations used when computing
the transport wind for a sampling step
that includes gradual rise (for CALMET
and PROFILE winds)
(NCOUNT)                                   Default: 2       ! NCOUNT =  2   !

Minimum sigma y for a new puff/slug (m)
(SYMIN)                                    Default: 1.0     ! SYMIN = 1.0  !

Minimum sigma z for a new puff/slug (m)
(SZMIN)                                    Default: 1.0     ! SZMIN = 1.0  !

Default minimum turbulence velocities
sigma-v and sigma-w for each
stability class (m/s)
(SVMIN(6) and SWMIN(6))     Default SVMIN : .50,  .50,  .50,  .50,  .50,  .50
                            Default SWMIN : .20,  .12,  .08,  .06,  .03,  .016

                          Stability Class :  A     B     C     D     E     F
                                            ---   ---   ---   ---   ---   ---
                                 ! SVMIN = 0.500, 0.500, 0.500, 0.500, 0.500,
0.500!
                                 ! SWMIN = 0.200, 0.120, 0.080, 0.060, 0.030,
```

```
0.016!

     Divergence criterion for dw/dz across puff
     used to initiate adjustment for horizontal
     convergence (1/s)
     Partial adjustment starts at CDIV(1), and
     full adjustment is reached at CDIV(2)
     (CDIV(2))                               Default: 0.0,0.0  ! CDIV = .01, .01
!

     Minimum wind speed (m/s) allowed for
     non-calm conditions. Also used as minimum
     speed returned when using power-law
     extrapolation toward surface
     (WSCALM)                                Default: 0.5    ! WSCALM = .5 !

     Maximum mixing height (m)
     (XMAXZI)                                Default: 3000.  ! XMAXZI = 3000.0 !

     Minimum mixing height (m)
     (XMINZI)                                Default: 50.    ! XMINZI = 50.0 !

     Default wind speed classes --
     5 upper bounds (m/s) are entered;
     the 6th class has no upper limit
     (WSCAT(5))                   Default   :
                                  ISC RURAL : 1.54, 3.09, 5.14, 8.23, 10,8
(10.8+)

                           Wind Speed Class :  1     2     3     4     5     6
                                              ---   ---   ---   ---   ---   ---
                                    ! WSCAT = 9.95, 10.49, 11.52, 12.04, 14.35 !

     Default wind speed profile power-law
     exponents for stabilities 1-6
     (PLX0(6))                    Default   : ISC RURAL values
                                  ISC RURAL : .07, .07, .10, .15, .35, .55
                                  ISC URBAN : .15, .15, .20, .25, .30, .30

                            Stability Class :  A     B     C     D     E     F
                                              ---   ---   ---   ---   ---   ---
                                     ! PLX0 = 0.07, 0.07, 0.10, 0.15, 0.35, 0.55
!

     Default potential temperature gradient
     for stable classes E, F (degK/m)
     (PTG0(2))                    Default: 0.020, 0.035
                                     ! PTG0 = 0.020,   0.035 !

     Default plume path coefficients for
     each stability class (used when option
     for partial plume height terrain adjustment
     is selected -- MCTADJ=3)
     (PPC(6))               Stability Class :  A     B     C     D     E     F
                               Default  PPC : .50,  .50,  .50,  .50,  .35,  .35
                                              ---   ---   ---   ---   ---   ---
                                     !  PPC = 0.50, 0.50, 0.50, 0.50, 0.35, 0.35
!

     Slug-to-puff transition criterion factor
     equal to sigma-y/length of slug
     (SL2PF)                            Default: 10.       ! SL2PF = 10.0 !
```

```
Puff-splitting control variables ------------------------

  VERTICAL SPLIT
  --------------

  Number of puffs that result every time a puff
  is split - nsplit=2 means that 1 puff splits
  into 2
  (NSPLIT)                          Default:   3        ! NSPLIT =  3  !

  Time(s) of a day when split puffs are eligible to
  be split once again; this is typically set once
  per day, around sunset before nocturnal shear develops.
  24 values: 0 is midnight (00:00) and 23 is 11 PM (23:00)
  0=do not re-split    1=eligible for re-split
  (IRESPLIT(24))                    Default:  Hour 17 = 1
  !  IRESPLIT = 0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,1,0,0,0,0,0,0 !

  Split is allowed only if last hour's mixing
  height (m) exceeds a minimum value
  (ZISPLIT)                         Default: 100.       ! ZISPLIT = 100.0 !

  Split is allowed only if ratio of last hour's
  mixing ht to the maximum mixing ht experienced
  by the puff is less than a maximum value (this
  postpones a split until a nocturnal layer develops)
  (ROLDMAX)                         Default: 0.25       ! ROLDMAX = 0.25 !


  HORIZONTAL SPLIT
  ----------------

  Number of puffs that result every time a puff
  is split - nsplith=5 means that 1 puff splits
  into 5
  (NSPLITH)                         Default:   5        ! NSPLITH =  5  !

  Minimum sigma-y (Grid Cells Units) of puff
  before it may be split
  (SYSPLITH)                        Default:  1.0       ! SYSPLITH = 1.0 !

  Minimum puff elongation rate (SYSPLITH/hr) due to
  wind shear, before it may be split
  (SHSPLITH)                        Default:  2.        ! SHSPLITH = 2.0 !

  Minimum concentration (g/m^3) of each
  species in puff before it may be split
  Enter array of NSPEC values; if a single value is
  entered, it will be used for ALL species
  (CNSPLITH)                        Default:  1.0E-07   ! CNSPLITH = 1.0E-07
!

Integration control variables ------------------------

  Fractional convergence criterion for numerical SLUG
  sampling integration
  (EPSSLUG)                         Default:   1.0e-04  ! EPSSLUG = 1.0E-04 !

  Fractional convergence criterion for numerical AREA
  source integration
  (EPSAREA)                         Default:   1.0e-06  ! EPSAREA = 1.0E-06 !

  Trajectory step-length (m) used for numerical rise
```

```
       integration
       (DSRISE)                            Default:   1.0      ! DSRISE = 1.0 !

!END!


-------------------------------------------------------------------------------


INPUT GROUPS: 13a, 13b, 13c, 13d -- Point source parameters
--------------------------------

---------------
Subgroup (13a)
---------------

     Number of point sources with
     parameters provided below      (NPT1)  No default  !  NPT1 =  4  !

     Units used for point source
     emissions below                (IPTU)  Default: 1  !  IPTU =   4  !
           1 =        g/s
           2 =       kg/hr
           3 =       lb/hr
           4 =     tons/yr
           5 =     Odour Unit * m**3/s  (vol. flux of odour compound)
           6 =     Odour Unit * m**3/min
           7 =     metric tons/yr

     Number of source-species
     combinations with variable
     emissions scaling factors
     provided below in (13d)        (NSPT1) Default: 0  !  NSPT1 =  0  !

     Number of point sources with
     variable emission parameters
     provided in external file      (NPT2)  No default  !  NPT2 =  0  !

     (If NPT2 > 0, these point
     source emissions are read from
     the file: PTEMARB.DAT)

!END!

---------------
Subgroup (13b)
---------------
                                              a
          POINT SOURCE: CONSTANT DATA
          -----------------------------
                                                                               b
    c
  Source      X UTM      Y UTM     Stack   Base     Stack    Exit  Exit    Bldg.
Emission
   No.     Coordinate Coordinate Height Elevation Diameter  Vel.  Temp.   Dwash
Rates
              (km)      (km)       (m)      (m)       (m)  (m/s) (deg. K)
  ------   ---------- ---------- ------  ------   -------- ----- -------- -----
--------
   1 ! SRCNAM = GK01 !
   1 ! X =  519.154,  5260.181,    42.7, 475.0,       2.4, 19.0, 330.0,  0.0,
6693.0E00,  0.0E00,
       21395.0E00,  0.0E00, 0.0E00,  4595.0E00 !
```

```
   1 ! FMFAC  =      1.0 !   !END!
   2 ! SRCNAM = SG01 !
   2 ! X = 519.154,  5260.181,    42.7, 475.0,        4.0, 14.0, 330.0,  0.0,
331.0E00,  0.0E00,
       4396.0E00,  0.0E00,  0.0E00,  358.0E00 !
   2 ! FMFAC  =      1.0 !   !END!
   3 ! SRCNAM = PC01 !
   3 ! X =  519.154,  5260.181,    41.1, 475.0,       4.0, 9.0, 700.0,  0.0, 0.0E00,
 0.0E00,  0.0E00,
       0.0E00,  0.0E00, 195.0E00   !
   3 ! FMFAC  =      1.0 !   !END!
   4 ! SRCNAM = OH01 !
   4 ! X = 519.154,  5260.181,    24.4, 475.0,       .61, 12.0, 298.0,  0.0, 0.0E00,
 0.0E00,  0.0E00,
       0.0E00,  0.0E00, 1027.0E00  !
   4 ! FMFAC  =      1.0 !   !END!


--------

    a
     Data for each source are treated as a separate input subgroup
     and therefore must end with an input group terminator.

     SRCNAM  is a 12-character name for a source
             (No default)
     X       is an array holding the source data listed by the column headings
             (No default)
     SIGYZI  is an array holding the initial sigma-y and sigma-z (m)
             (Default: 0.,0.)
     FMFAC   is a vertical momentum flux factor (0. or 1.0) used to represent
             the effect of rain-caps or other physical configurations that
             reduce momentum rise associated with the actual exit velocity.
             (Default: 1.0  -- full momentum used)

    b
     0. = No building downwash modeled, 1. = downwash modeled
     NOTE: must be entered as a REAL number (i.e., with decimal point)

    c
     An emission rate must be entered for every pollutant modeled.
     Enter emission rate of zero for secondary pollutants that are
     modeled, but not emitted.  Units are specified by IPTU
     (e.g. 1 for g/s).

---------------
Subgroup (13c)
---------------

           BUILDING DIMENSION DATA FOR SOURCES SUBJECT TO DOWNWASH
           -------------------------------------------------------
Source                                                                a
 No.       Effective building width and height (in meters) every 10 degrees
------     ----------------------------------------------------------------

 *END*

--------

    a
     Each pair of width and height values is treated as a separate input
     subgroup and therefore must end with an input group terminator.
```

```
---------------
Subgroup (13d)
---------------
                                                a
          POINT SOURCE: VARIABLE EMISSIONS DATA
          ---------------------------------------

     Use this subgroup to describe temporal variations in the emission
     rates given in 13b.  Factors entered multiply the rates in 13b.
     Skip sources here that have constant emissions.  For more elaborate
     variation in source parameters, use PTEMARB.DAT and NPT2 > 0.

     IVARY determines the type of variation, and is source-specific:
     (IVARY)                                Default: 0
           0 =       Constant
           1 =       Diurnal cycle (24 scaling factors: hours 1-24)
           2 =       Monthly cycle (12 scaling factors: months 1-12)
           3 =       Hour & Season (4 groups of 24 hourly scaling factors,
                                    where first group is DEC-JAN-FEB)
           4 =       Speed & Stab. (6 groups of 6 scaling factors, where
                                    first group is Stability Class A,
                                    and the speed classes have upper
                                    bounds (m/s) defined in Group 12
           5 =       Temperature   (12 scaling factors, where temperature
                                    classes have upper bounds (C) of:
                                    0, 5, 10, 15, 20, 25, 30, 35, 40,
                                    45, 50, 50+)



--------
    a
     Data for each species are treated as a separate input subgroup
     and therefore must end with an input group terminator.


-------------------------------------------------------------------------------


INPUT GROUPS: 14a, 14b, 14c, 14d -- Area source parameters
--------------------------------

---------------
Subgroup (14a)
---------------

     Number of polygon area sources with
     parameters specified below (NAR1)       No default  !  NAR1 =  0   !

     Units used for area source
     emissions below            (IARU)       Default: 1  !  IARU =   1  !
           1 =        g/m**2/s
           2 =       kg/m**2/hr
           3 =       lb/m**2/hr
           4 =     tons/m**2/yr
           5 =     Odour Unit * m/s  (vol. flux/m**2 of odour compound)
           6 =     Odour Unit * m/min
           7 =     metric tons/m**2/yr

     Number of source-species
     combinations with variable
     emissions scaling factors
     provided below in (14d)       (NSAR1) Default: 0  !  NSAR1 =  0  !
```

```
     Number of buoyant polygon area sources
     with variable location and emission
     parameters (NAR2)                       No default  !  NAR2 =  0   !
     (If NAR2 > 0, ALL parameter data for
     these sources are read from the file: BAEMARB.DAT)

!END!

---------------
Subgroup (14b)
---------------
                                     a
          AREA SOURCE: CONSTANT DATA
          ----------------------------
                                                             b
Source           Effect.    Base      Initial    Emission
 No.             Height   Elevation   Sigma z     Rates
                   (m)       (m)        (m)
-------          ------    ------     --------   ---------


--------
    a
     Data for each source are treated as a separate input subgroup
     and therefore must end with an input group terminator.
    b
     An emission rate must be entered for every pollutant modeled.
     Enter emission rate of zero for secondary pollutants that are
     modeled, but not emitted.  Units are specified by IARU
     (e.g. 1 for g/m**2/s).

---------------
Subgroup (14c)
---------------

           COORDINATES (UTM-km) FOR EACH VERTEX(4) OF EACH POLYGON
           --------------------------------------------------------
Source                                                              a
 No.       Ordered list of X followed by list of Y, grouped by source
------     ------------------------------------------------------------


--------
    a
     Data for each source are treated as a separate input subgroup
     and therefore must end with an input group terminator.


---------------
Subgroup (14d)
---------------
                                               a
          AREA SOURCE: VARIABLE EMISSIONS DATA
          --------------------------------------

     Use this subgroup to describe temporal variations in the emission
     rates given in 14b.  Factors entered multiply the rates in 14b.
     Skip sources here that have constant emissions.  For more elaborate
     variation in source parameters, use BAEMARB.DAT and NAR2 > 0.

     IVARY determines the type of variation, and is source-specific:
     (IVARY)                                 Default: 0
```

```
        0 =       Constant
        1 =       Diurnal cycle (24 scaling factors: hours 1-24)
        2 =       Monthly cycle (12 scaling factors: months 1-12)
        3 =       Hour & Season (4 groups of 24 hourly scaling factors,
                                 where first group is DEC-JAN-FEB)
        4 =       Speed & Stab. (6 groups of 6 scaling factors, where
                                 first group is Stability Class A,
                                 and the speed classes have upper
                                 bounds (m/s) defined in Group 12
        5 =       Temperature   (12 scaling factors, where temperature
                                 classes have upper bounds (C) of:
                                 0, 5, 10, 15, 20, 25, 30, 35, 40,
                                 45, 50, 50+)


--------
    a
     Data for each species are treated as a separate input subgroup
     and therefore must end with an input group terminator.


-------------------------------------------------------------------------------

INPUT GROUPS: 15a, 15b, 15c -- Line source parameters
---------------------------

---------------
Subgroup (15a)
---------------

     Number of buoyant line sources
     with variable location and emission
     parameters (NLN2)                              No default  !  NLN2 =  0   !

     (If NLN2 > 0, ALL parameter data for
      these sources are read from the file: LNEMARB.DAT)

     Number of buoyant line sources (NLINES)        No default   ! NLINES =  0  !

     Units used for line source
     emissions below               (ILNU)           Default: 1  !  ILNU =   1  !
           1 =        g/s
           2 =       kg/hr
           3 =       lb/hr
           4 =     tons/yr
           5 =     Odour Unit * m**3/s  (vol. flux of odour compound)
           6 =     Odour Unit * m**3/min
           7 =     metric tons/yr

     Number of source-species
     combinations with variable
     emissions scaling factors
     provided below in (15c)       (NSLN1) Default: 0  !  NSLN1 =  0  !

     Maximum number of segments used to model
     each line (MXNSEG)                             Default: 7   ! MXNSEG =  7  !

     The following variables are required only if NLINES > 0.  They are
     used in the buoyant line source plume rise calculations.

        Number of distances at which                Default: 6   ! NLRISE =  6  !
        transitional rise is computed
```

```
        Average building length (XL)               No default   ! XL = .0 !
                                                   (in meters)

        Average building height (HBL)              No default   ! HBL = .0 !
                                                   (in meters)

        Average building width (WBL)               No default   ! WBL = .0 !
                                                   (in meters)

        Average line source width (WML)            No default   ! WML = .0 !
                                                   (in meters)

        Average separation between buildings (DXL)  No default   ! DXL = .0 !
                                                   (in meters)

        Average buoyancy parameter (FPRIMEL)       No default   ! FPRIMEL = .0 !
                                                   (in m**4/s**3)

!END!

---------------
Subgroup (15b)
---------------

          BUOYANT LINE SOURCE: CONSTANT DATA
          ----------------------------------

     a
Source     Beg. X      Beg. Y      End. X    End. Y     Release    Base
Emission
 No.     Coordinate  Coordinate  Coordinate Coordinate  Height    Elevation
Rates
            (km)        (km)        (km)       (km)       (m)       (m)
------   ----------  ----------  ---------  ----------  -------   ---------
---------

--------

    a
     Data for each source are treated as a separate input subgroup
     and therefore must end with an input group terminator.

    b
     An emission rate must be entered for every pollutant modeled.
     Enter emission rate of zero for secondary pollutants that are
     modeled, but not emitted.  Units are specified by ILNTU
     (e.g. 1 for g/s).

---------------
Subgroup (15c)
---------------
                                                               a
          BUOYANT LINE SOURCE: VARIABLE EMISSIONS DATA
          --------------------------------------------

     Use this subgroup to describe temporal variations in the emission
     rates given in 15b.  Factors entered multiply the rates in 15b.
     Skip sources here that have constant emissions.

     IVARY determines the type of variation, and is source-specific:
     (IVARY)                               Default: 0
           0 =       Constant
```

```
        1 =       Diurnal cycle (24 scaling factors: hours 1-24)
        2 =       Monthly cycle (12 scaling factors: months 1-12)
        3 =       Hour & Season (4 groups of 24 hourly scaling factors,
                                 where first group is DEC-JAN-FEB)
        4 =       Speed & Stab. (6 groups of 6 scaling factors, where
                                 first group is Stability Class A,
                                 and the speed classes have upper
                                 bounds (m/s) defined in Group 12
        5 =       Temperature   (12 scaling factors, where temperature
                                 classes have upper bounds (C) of:
                                 0, 5, 10, 15, 20, 25, 30, 35, 40,
                                 45, 50, 50+)


--------
   a
    Data for each species are treated as a separate input subgroup
    and therefore must end with an input group terminator.


-------------------------------------------------------------------------------


INPUT GROUPS: 16a, 16b, 16c -- Volume source parameters
---------------------------

---------------
Subgroup (16a)
---------------

     Number of volume sources with
     parameters provided in 16b,c (NVL1)     No default  !  NVL1 =  0   !

     Units used for volume source
     emissions below in 16b       (IVLU)     Default: 1  !  IVLU =   1  !
           1 =        g/s
           2 =       kg/hr
           3 =       lb/hr
           4 =     tons/yr
           5 =     Odour Unit * m**3/s  (vol. flux of odour compound)
           6 =     Odour Unit * m**3/min
           7 =     metric tons/yr

     Number of source-species
     combinations with variable
     emissions scaling factors
     provided below in (16c)      (NSVL1)    Default: 0  !  NSVL1 =  0  !

     Number of volume sources with
     variable location and emission
     parameters                   (NVL2)     No default  !  NVL2 =   0   !

     (If NVL2 > 0, ALL parameter data for
      these sources are read from the VOLEMARB.DAT file(s) )

!END!

---------------
Subgroup (16b)
---------------
                                        a
           VOLUME SOURCE: CONSTANT DATA
```

```
        ------------------------------
                                                                              b
     X UTM      Y UTM       Effect.    Base      Initial    Initial    Emission
  Coordinate  Coordinate    Height   Elevation   Sigma y    Sigma z     Rates
     (km)        (km)         (m)       (m)        (m)        (m)
  ----------  ----------    ------    ------    --------   --------   --------


--------
    a
     Data for each source are treated as a separate input subgroup
     and therefore must end with an input group terminator.

    b
     An emission rate must be entered for every pollutant modeled.
     Enter emission rate of zero for secondary pollutants that are
     modeled, but not emitted.  Units are specified by IVLU
     (e.g. 1 for g/s).

---------------
Subgroup (16c)
---------------
                                                      a
          VOLUME SOURCE: VARIABLE EMISSIONS DATA
          ----------------------------------------

     Use this subgroup to describe temporal variations in the emission
     rates given in 16b.  Factors entered multiply the rates in 16b.
     Skip sources here that have constant emissions.  For more elaborate
     variation in source parameters, use VOLEMARB.DAT and NVL2 > 0.

     IVARY determines the type of variation, and is source-specific:
     (IVARY)                               Default: 0
           0 =       Constant
           1 =       Diurnal cycle (24 scaling factors: hours 1-24)
           2 =       Monthly cycle (12 scaling factors: months 1-12)
           3 =       Hour & Season (4 groups of 24 hourly scaling factors,
                                    where first group is DEC-JAN-FEB)
           4 =       Speed & Stab. (6 groups of 6 scaling factors, where
                                    first group is Stability Class A,
                                    and the speed classes have upper
                                    bounds (m/s) defined in Group 12
           5 =       Temperature   (12 scaling factors, where temperature
                                    classes have upper bounds (C) of:
                                    0, 5, 10, 15, 20, 25, 30, 35, 40,
                                    45, 50, 50+)



--------
    a
     Data for each species are treated as a separate input subgroup
     and therefore must end with an input group terminator.


-------------------------------------------------------------------------------

INPUT GROUPS: 17a & 17b -- Non-gridded (discrete) receptor information
-----------------------

---------------
Subgroup (17a)
---------------
```

```
     Number of non-gridded receptors (NREC)  No default  !  NREC =  500   !

!END!

---------------
Subgroup (17b)
---------------
                                                     a
           NON-GRIDDED (DISCRETE) RECEPTOR DATA
           ------------------------------------

                     X UTM       Y UTM        Ground       Height   b
Receptor          Coordinate  Coordinate    Elevation   Above Ground
  No.                (km)        (km)          (m)           (m)
--------          ----------  ----------    ---------   ------------
     1 ! X =       610.77,    5292.41,      472.000,       0.000!   !END!
     2 ! X =       612.77,    5292.41,      473.000,       0.000!   !END!
     3 ! X =       614.77,    5292.41,      473.900,       0.000!   !END!
     4 ! X =       618.77,    5292.41,      471.200,       0.000!   !END!
     5 ! X =       620.77,    5292.41,      474.800,       0.000!   !END!
     6 ! X =       606.77,    5294.41,      458.400,       0.000!   !END!
     7 ! X =       608.77,    5294.41,      470.900,       0.000!   !END!
     8 ! X =       610.77,    5294.41,      459.700,       0.000!   !END!
     9 ! X =       612.77,    5294.41,      474.800,       0.000!   !END!
    10 ! X =       614.77,    5294.41,      468.000,       0.000!   !END!
    11 ! X =       616.77,    5294.41,      469.300,       0.000!   !END!
    12 ! X =       618.77,    5294.41,      463.400,       0.000!   !END!
    13 ! X =       620.77,    5294.41,      472.000,       0.000!   !END!
    14 ! X =       622.77,    5294.41,      487.000,       0.000!   !END!
    15 ! X =       624.77,    5294.41,      468.700,       0.000!   !END!
    16 ! X =       630.77,    5294.41,      491.600,       0.000!   !END!
    17 ! X =       632.77,    5294.41,      493.800,       0.000!   !END!
    18 ! X =       634.77,    5294.41,      503.000,       0.000!   !END!
    19 ! X =       636.77,    5294.41,      511.100,       0.000!   !END!
    20 ! X =       638.77,    5294.41,      502.000,       0.000!   !END!
    21 ! X =       604.77,    5296.41,      500.900,       0.000!   !END!
    22 ! X =       606.77,    5296.41,      460.600,       0.000!   !END!
    23 ! X =       608.77,    5296.41,      449.100,       0.000!   !END!
    24 ! X =       610.77,    5296.41,      464.900,       0.000!   !END!
    25 ! X =       612.77,    5296.41,      472.000,       0.000!   !END!
    26 ! X =       614.77,    5296.41,      457.000,       0.000!   !END!
    27 ! X =       616.77,    5296.41,      466.400,       0.000!   !END!
    28 ! X =       618.77,    5296.41,      457.000,       0.000!   !END!
    29 ! X =       620.77,    5296.41,      466.700,       0.000!   !END!
    30 ! X =       622.77,    5296.41,      482.000,       0.000!   !END!
    31 ! X =       624.77,    5296.41,      472.000,       0.000!   !END!
    32 ! X =       626.77,    5296.41,      478.000,       0.000!   !END!
    33 ! X =       628.77,    5296.41,      478.000,       0.000!   !END!
    34 ! X =       630.77,    5296.41,      487.000,       0.000!   !END!
    35 ! X =       632.77,    5296.41,      487.100,       0.000!   !END!
    36 ! X =       634.77,    5296.41,      502.000,       0.000!   !END!
    37 ! X =       636.77,    5296.41,      502.000,       0.000!   !END!
    38 ! X =       638.77,    5296.41,      500.700,       0.000!   !END!
    39 ! X =       604.77,    5298.41,      463.600,       0.000!   !END!
    40 ! X =       606.77,    5298.41,      467.000,       0.000!   !END!
    41 ! X =       608.77,    5298.41,      441.000,       0.000!   !END!
    42 ! X =       610.77,    5298.41,      469.400,       0.000!   !END!
    43 ! X =       612.77,    5298.41,      472.000,       0.000!   !END!
    44 ! X =       614.77,    5298.41,      472.000,       0.000!   !END!
    45 ! X =       616.77,    5298.41,      472.000,       0.000!   !END!
    46 ! X =       618.77,    5298.41,      472.000,       0.000!   !END!
    47 ! X =       620.77,    5298.41,      472.000,       0.000!   !END!
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 48 ! X =      622.77,   5298.41,    472.000,      0.000!   !END!
 49 ! X =      624.77,   5298.41,    476.600,      0.000!   !END!
 50 ! X =      626.77,   5298.41,    485.000,      0.000!   !END!
 51 ! X =      628.77,   5298.41,    486.500,      0.000!   !END!
 52 ! X =      630.77,   5298.41,    487.000,      0.000!   !END!
 53 ! X =      632.77,   5298.41,    500.000,      0.000!   !END!
 54 ! X =      634.77,   5298.41,    502.000,      0.000!   !END!
 55 ! X =      636.77,   5298.41,    517.500,      0.000!   !END!
 56 ! X =      638.77,   5298.41,    518.000,      0.000!   !END!
 57 ! X =      602.77,   5300.41,    450.900,      0.000!   !END!
 58 ! X =      604.77,   5300.41,    441.000,      0.000!   !END!
 59 ! X =      606.77,   5300.41,    442.300,      0.000!   !END!
 60 ! X =      608.77,   5300.41,    462.300,      0.000!   !END!
 61 ! X =      610.77,   5300.41,    462.300,      0.000!   !END!
 62 ! X =      612.77,   5300.41,    463.000,      0.000!   !END!
 63 ! X =      614.77,   5300.41,    479.300,      0.000!   !END!
 64 ! X =      616.77,   5300.41,    474.400,      0.000!   !END!
 65 ! X =      618.77,   5300.41,    483.100,      0.000!   !END!
 66 ! X =      620.77,   5300.41,    481.100,      0.000!   !END!
 67 ! X =      622.77,   5300.41,    487.000,      0.000!   !END!
 68 ! X =      624.77,   5300.41,    487.000,      0.000!   !END!
 69 ! X =      626.77,   5300.41,    504.500,      0.000!   !END!
 70 ! X =      628.77,   5300.41,    490.700,      0.000!   !END!
 71 ! X =      630.77,   5300.41,    505.900,      0.000!   !END!
 72 ! X =      632.77,   5300.41,    514.200,      0.000!   !END!
 73 ! X =      634.77,   5300.41,    512.400,      0.000!   !END!
 74 ! X =      636.77,   5300.41,    517.300,      0.000!   !END!
 75 ! X =      638.77,   5300.41,    519.400,      0.000!   !END!
 76 ! X =      640.77,   5300.41,    516.500,      0.000!   !END!
 77 ! X =      642.77,   5300.41,    518.300,      0.000!   !END!
 78 ! X =      644.77,   5300.41,    539.600,      0.000!   !END!
 79 ! X =      646.77,   5300.41,    549.000,      0.000!   !END!
 80 ! X =      648.77,   5300.41,    544.600,      0.000!   !END!
 81 ! X =      650.77,   5300.41,    588.700,      0.000!   !END!
 82 ! X =      652.77,   5300.41,    572.800,      0.000!   !END!
 83 ! X =      654.77,   5300.41,    562.200,      0.000!   !END!
 84 ! X =      656.77,   5300.41,    590.000,      0.000!   !END!
 85 ! X =      600.77,   5302.41,    435.000,      0.000!   !END!
 86 ! X =      602.77,   5302.41,    438.400,      0.000!   !END!
 87 ! X =      604.77,   5302.41,    458.000,      0.000!   !END!
 88 ! X =      606.77,   5302.41,    453.400,      0.000!   !END!
 89 ! X =      608.77,   5302.41,    471.000,      0.000!   !END!
 90 ! X =      610.77,   5302.41,    472.000,      0.000!   !END!
 91 ! X =      612.77,   5302.41,    474.800,      0.000!   !END!
 92 ! X =      614.77,   5302.41,    498.300,      0.000!   !END!
 93 ! X =      616.77,   5302.41,    481.800,      0.000!   !END!
 94 ! X =      618.77,   5302.41,    472.000,      0.000!   !END!
 95 ! X =      620.77,   5302.41,    468.000,      0.000!   !END!
 96 ! X =      622.77,   5302.41,    472.000,      0.000!   !END!
 97 ! X =      624.77,   5302.41,    472.000,      0.000!   !END!
 98 ! X =      626.77,   5302.41,    489.900,      0.000!   !END!
 99 ! X =      628.77,   5302.41,    487.000,      0.000!   !END!
100 ! X =      630.77,   5302.41,    507.300,      0.000!   !END!
101 ! X =      632.77,   5302.41,    518.000,      0.000!   !END!
102 ! X =      634.77,   5302.41,    547.900,      0.000!   !END!
103 ! X =      636.77,   5302.41,    517.200,      0.000!   !END!
104 ! X =      638.77,   5302.41,    528.500,      0.000!   !END!
105 ! X =      640.77,   5302.41,    517.400,      0.000!   !END!
106 ! X =      642.77,   5302.41,    520.400,      0.000!   !END!
107 ! X =      644.77,   5302.41,    532.700,      0.000!   !END!
108 ! X =      646.77,   5302.41,    576.300,      0.000!   !END!
109 ! X =      648.77,   5302.41,    542.000,      0.000!   !END!
110 ! X =      650.77,   5302.41,    558.300,      0.000!   !END!
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111 ! X =       652.77,    5302.41,     589.600,       0.000!   !END!
112 ! X =       654.77,    5302.41,     578.600,       0.000!   !END!
113 ! X =       656.77,    5302.41,     573.200,       0.000!   !END!
114 ! X =       662.77,    5302.41,     531.500,       0.000!   !END!
115 ! X =       664.77,    5302.41,     548.000,       0.000!   !END!
116 ! X =       666.77,    5302.41,     563.000,       0.000!   !END!
117 ! X =       668.77,    5302.41,     548.800,       0.000!   !END!
118 ! X =       598.77,    5304.41,     451.000,       0.000!   !END!
119 ! X =       600.77,    5304.41,     454.200,       0.000!   !END!
120 ! X =       602.77,    5304.41,     438.000,       0.000!   !END!
121 ! X =       604.77,    5304.41,     449.100,       0.000!   !END!
122 ! X =       606.77,    5304.41,     461.800,       0.000!   !END!
123 ! X =       608.77,    5304.41,     469.000,       0.000!   !END!
124 ! X =       610.77,    5304.41,     470.000,       0.000!   !END!
125 ! X =       612.77,    5304.41,     463.300,       0.000!   !END!
126 ! X =       614.77,    5304.41,     457.000,       0.000!   !END!
127 ! X =       616.77,    5304.41,     451.000,       0.000!   !END!
128 ! X =       618.77,    5304.41,     457.000,       0.000!   !END!
129 ! X =       620.77,    5304.41,     456.300,       0.000!   !END!
130 ! X =       622.77,    5304.41,     472.000,       0.000!   !END!
131 ! X =       624.77,    5304.41,     472.000,       0.000!   !END!
132 ! X =       626.77,    5304.41,     473.000,       0.000!   !END!
133 ! X =       628.77,    5304.41,     487.000,       0.000!   !END!
134 ! X =       630.77,    5304.41,     476.900,       0.000!   !END!
135 ! X =       632.77,    5304.41,     487.000,       0.000!   !END!
136 ! X =       634.77,    5304.41,     488.500,       0.000!   !END!
137 ! X =       636.77,    5304.41,     517.000,       0.000!   !END!
138 ! X =       638.77,    5304.41,     521.000,       0.000!   !END!
139 ! X =       640.77,    5304.41,     503.800,       0.000!   !END!
140 ! X =       642.77,    5304.41,     521.400,       0.000!   !END!
141 ! X =       644.77,    5304.41,     533.000,       0.000!   !END!
142 ! X =       646.77,    5304.41,     548.000,       0.000!   !END!
143 ! X =       648.77,    5304.41,     542.600,       0.000!   !END!
144 ! X =       650.77,    5304.41,     576.000,       0.000!   !END!
145 ! X =       652.77,    5304.41,     554.000,       0.000!   !END!
146 ! X =       654.77,    5304.41,     583.400,       0.000!   !END!
147 ! X =       656.77,    5304.41,     557.000,       0.000!   !END!
148 ! X =       660.77,    5304.41,     562.000,       0.000!   !END!
149 ! X =       662.77,    5304.41,     575.500,       0.000!   !END!
150 ! X =       664.77,    5304.41,     576.100,       0.000!   !END!
151 ! X =       666.77,    5304.41,     568.400,       0.000!   !END!
152 ! X =       668.77,    5304.41,     619.300,       0.000!   !END!
153 ! X =       670.77,    5304.41,     586.000,       0.000!   !END!
154 ! X =       554.77,    5306.41,     426.000,       0.000!   !END!
155 ! X =       556.77,    5306.41,     440.400,       0.000!   !END!
156 ! X =       558.77,    5306.41,     442.800,       0.000!   !END!
157 ! X =       560.77,    5306.41,     448.800,       0.000!   !END!
158 ! X =       562.77,    5306.41,     471.300,       0.000!   !END!
159 ! X =       564.77,    5306.41,     481.200,       0.000!   !END!
160 ! X =       566.77,    5306.41,     476.500,       0.000!   !END!
161 ! X =       568.77,    5306.41,     442.000,       0.000!   !END!
162 ! X =       570.77,    5306.41,     429.100,       0.000!   !END!
163 ! X =       596.77,    5306.41,     420.200,       0.000!   !END!
164 ! X =       598.77,    5306.41,     435.200,       0.000!   !END!
165 ! X =       600.77,    5306.41,     451.200,       0.000!   !END!
166 ! X =       602.77,    5306.41,     438.000,       0.000!   !END!
167 ! X =       604.77,    5306.41,     462.000,       0.000!   !END!
168 ! X =       606.77,    5306.41,     445.000,       0.000!   !END!
169 ! X =       608.77,    5306.41,     473.000,       0.000!   !END!
170 ! X =       610.77,    5306.41,     471.600,       0.000!   !END!
171 ! X =       612.77,    5306.41,     472.000,       0.000!   !END!
172 ! X =       614.77,    5306.41,     453.400,       0.000!   !END!
173 ! X =       616.77,    5306.41,     451.000,       0.000!   !END!
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174 ! X =       618.77,    5306.41,     451.000,        0.000!   !END!
175 ! X =       620.77,    5306.41,     454.000,        0.000!   !END!
176 ! X =       622.77,    5306.41,     454.000,        0.000!   !END!
177 ! X =       624.77,    5306.41,     465.500,        0.000!   !END!
178 ! X =       626.77,    5306.41,     472.000,        0.000!   !END!
179 ! X =       628.77,    5306.41,     470.400,        0.000!   !END!
180 ! X =       630.77,    5306.41,     472.000,        0.000!   !END!
181 ! X =       632.77,    5306.41,     488.500,        0.000!   !END!
182 ! X =       634.77,    5306.41,     498.600,        0.000!   !END!
183 ! X =       636.77,    5306.41,     525.300,        0.000!   !END!
184 ! X =       638.77,    5306.41,     518.600,        0.000!   !END!
185 ! X =       640.77,    5306.41,     502.000,        0.000!   !END!
186 ! X =       642.77,    5306.41,     502.000,        0.000!   !END!
187 ! X =       644.77,    5306.41,     521.400,        0.000!   !END!
188 ! X =       646.77,    5306.41,     562.100,        0.000!   !END!
189 ! X =       648.77,    5306.41,     569.300,        0.000!   !END!
190 ! X =       650.77,    5306.41,     605.000,        0.000!   !END!
191 ! X =       652.77,    5306.41,     579.200,        0.000!   !END!
192 ! X =       654.77,    5306.41,     563.000,        0.000!   !END!
193 ! X =       656.77,    5306.41,     559.300,        0.000!   !END!
194 ! X =       658.77,    5306.41,     553.900,        0.000!   !END!
195 ! X =       660.77,    5306.41,     548.000,        0.000!   !END!
196 ! X =       662.77,    5306.41,     548.000,        0.000!   !END!
197 ! X =       664.77,    5306.41,     530.700,        0.000!   !END!
198 ! X =       666.77,    5306.41,     563.900,        0.000!   !END!
199 ! X =       668.77,    5306.41,     562.600,        0.000!   !END!
200 ! X =       670.77,    5306.41,     563.000,        0.000!   !END!
201 ! X =       672.77,    5306.41,     562.500,        0.000!   !END!
202 ! X =       680.77,    5306.41,     563.000,        0.000!   !END!
203 ! X =       682.77,    5306.41,     556.700,        0.000!   !END!
204 ! X =       548.77,    5308.41,     454.000,        0.000!   !END!
205 ! X =       550.77,    5308.41,     428.600,        0.000!   !END!
206 ! X =       552.77,    5308.41,     441.400,        0.000!   !END!
207 ! X =       554.77,    5308.41,     453.600,        0.000!   !END!
208 ! X =       556.77,    5308.41,     442.000,        0.000!   !END!
209 ! X =       558.77,    5308.41,     456.600,        0.000!   !END!
210 ! X =       560.77,    5308.41,     461.300,        0.000!   !END!
211 ! X =       562.77,    5308.41,     485.300,        0.000!   !END!
212 ! X =       564.77,    5308.41,     472.000,        0.000!   !END!
213 ! X =       566.77,    5308.41,     466.100,        0.000!   !END!
214 ! X =       568.77,    5308.41,     457.000,        0.000!   !END!
215 ! X =       570.77,    5308.41,     443.300,        0.000!   !END!
216 ! X =       604.77,    5308.41,     451.600,        0.000!   !END!
217 ! X =       606.77,    5308.41,     470.300,        0.000!   !END!
218 ! X =       608.77,    5308.41,     448.500,        0.000!   !END!
219 ! X =       610.77,    5308.41,     457.000,        0.000!   !END!
220 ! X =       612.77,    5308.41,     451.000,        0.000!   !END!
221 ! X =       614.77,    5308.41,     457.000,        0.000!   !END!
222 ! X =       616.77,    5308.41,     456.000,        0.000!   !END!
223 ! X =       618.77,    5308.41,     457.000,        0.000!   !END!
224 ! X =       620.77,    5308.41,     458.500,        0.000!   !END!
225 ! X =       622.77,    5308.41,     461.300,        0.000!   !END!
226 ! X =       624.77,    5308.41,     479.200,        0.000!   !END!
227 ! X =       626.77,    5308.41,     461.000,        0.000!   !END!
228 ! X =       628.77,    5308.41,     460.000,        0.000!   !END!
229 ! X =       630.77,    5308.41,     472.600,        0.000!   !END!
230 ! X =       632.77,    5308.41,     484.100,        0.000!   !END!
231 ! X =       634.77,    5308.41,     483.800,        0.000!   !END!
232 ! X =       636.77,    5308.41,     530.600,        0.000!   !END!
233 ! X =       638.77,    5308.41,     499.200,        0.000!   !END!
234 ! X =       640.77,    5308.41,     503.000,        0.000!   !END!
235 ! X =       642.77,    5308.41,     505.400,        0.000!   !END!
236 ! X =       644.77,    5308.41,     532.200,        0.000!   !END!
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237 ! X =       646.77,    5308.41,     533.000,        0.000!    !END!
238 ! X =       648.77,    5308.41,     576.800,        0.000!    !END!
239 ! X =       650.77,    5308.41,     591.900,        0.000!    !END!
240 ! X =       652.77,    5308.41,     593.000,        0.000!    !END!
241 ! X =       654.77,    5308.41,     594.400,        0.000!    !END!
242 ! X =       656.77,    5308.41,     561.100,        0.000!    !END!
243 ! X =       658.77,    5308.41,     548.000,        0.000!    !END!
244 ! X =       660.77,    5308.41,     563.000,        0.000!    !END!
245 ! X =       662.77,    5308.41,     594.000,        0.000!    !END!
246 ! X =       664.77,    5308.41,     539.400,        0.000!    !END!
247 ! X =       666.77,    5308.41,     563.000,        0.000!    !END!
248 ! X =       668.77,    5308.41,     566.000,        0.000!    !END!
249 ! X =       670.77,    5308.41,     566.600,        0.000!    !END!
250 ! X =       680.77,    5308.41,     573.500,        0.000!    !END!
251 ! X =       682.77,    5308.41,     595.900,        0.000!    !END!
252 ! X =       546.77,    5310.41,     457.000,        0.000!    !END!
253 ! X =       548.77,    5310.41,     438.300,        0.000!    !END!
254 ! X =       550.77,    5310.41,     427.000,        0.000!    !END!
255 ! X =       552.77,    5310.41,     427.000,        0.000!    !END!
256 ! X =       554.77,    5310.41,     442.200,        0.000!    !END!
257 ! X =       556.77,    5310.41,     470.000,        0.000!    !END!
258 ! X =       558.77,    5310.41,     472.000,        0.000!    !END!
259 ! X =       560.77,    5310.41,     456.800,        0.000!    !END!
260 ! X =       562.77,    5310.41,     472.000,        0.000!    !END!
261 ! X =       564.77,    5310.41,     486.700,        0.000!    !END!
262 ! X =       566.77,    5310.41,     479.500,        0.000!    !END!
263 ! X =       568.77,    5310.41,     472.000,        0.000!    !END!
264 ! X =       570.77,    5310.41,     445.000,        0.000!    !END!
265 ! X =       620.77,    5310.41,     471.100,        0.000!    !END!
266 ! X =       622.77,    5310.41,     472.000,        0.000!    !END!
267 ! X =       624.77,    5310.41,     486.900,        0.000!    !END!
268 ! X =       626.77,    5310.41,     484.800,        0.000!    !END!
269 ! X =       628.77,    5310.41,     471.200,        0.000!    !END!
270 ! X =       630.77,    5310.41,     471.000,        0.000!    !END!
271 ! X =       632.77,    5310.41,     484.000,        0.000!    !END!
272 ! X =       634.77,    5310.41,     486.600,        0.000!    !END!
273 ! X =       636.77,    5310.41,     514.900,        0.000!    !END!
274 ! X =       638.77,    5310.41,     488.400,        0.000!    !END!
275 ! X =       640.77,    5310.41,     488.900,        0.000!    !END!
276 ! X =       642.77,    5310.41,     487.000,        0.000!    !END!
277 ! X =       644.77,    5310.41,     517.200,        0.000!    !END!
278 ! X =       646.77,    5310.41,     532.800,        0.000!    !END!
279 ! X =       648.77,    5310.41,     562.500,        0.000!    !END!
280 ! X =       650.77,    5310.41,     593.000,        0.000!    !END!
281 ! X =       652.77,    5310.41,     609.000,        0.000!    !END!
282 ! X =       654.77,    5310.41,     609.000,        0.000!    !END!
283 ! X =       656.77,    5310.41,     563.000,        0.000!    !END!
284 ! X =       658.77,    5310.41,     563.000,        0.000!    !END!
285 ! X =       660.77,    5310.41,     563.000,        0.000!    !END!
286 ! X =       662.77,    5310.41,     574.000,        0.000!    !END!
287 ! X =       664.77,    5310.41,     563.000,        0.000!    !END!
288 ! X =       666.77,    5310.41,     578.000,        0.000!    !END!
289 ! X =       668.77,    5310.41,     578.400,        0.000!    !END!
290 ! X =       670.77,    5310.41,     593.700,        0.000!    !END!
291 ! X =       672.77,    5310.41,     561.200,        0.000!    !END!
292 ! X =       676.77,    5310.41,     565.000,        0.000!    !END!
293 ! X =       678.77,    5310.41,     624.000,        0.000!    !END!
294 ! X =       680.77,    5310.41,     610.500,        0.000!    !END!
295 ! X =       682.77,    5310.41,     595.100,        0.000!    !END!
296 ! X =       684.77,    5310.41,     595.400,        0.000!    !END!
297 ! X =       686.77,    5310.41,     603.900,        0.000!    !END!
298 ! X =       688.77,    5310.41,     608.000,        0.000!    !END!
299 ! X =       546.77,    5312.41,     435.900,        0.000!    !END!
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300 ! X =       548.77,    5312.41,     455.000,        0.000!   !END!
301 ! X =       550.77,    5312.41,     427.000,        0.000!   !END!
302 ! X =       552.77,    5312.41,     427.000,        0.000!   !END!
303 ! X =       554.77,    5312.41,     457.000,        0.000!   !END!
304 ! X =       556.77,    5312.41,     467.400,        0.000!   !END!
305 ! X =       558.77,    5312.41,     472.000,        0.000!   !END!
306 ! X =       560.77,    5312.41,     457.000,        0.000!   !END!
307 ! X =       562.77,    5312.41,     482.300,        0.000!   !END!
308 ! X =       564.77,    5312.41,     472.000,        0.000!   !END!
309 ! X =       566.77,    5312.41,     465.300,        0.000!   !END!
310 ! X =       568.77,    5312.41,     457.000,        0.000!   !END!
311 ! X =       570.77,    5312.41,     467.200,        0.000!   !END!
312 ! X =       572.77,    5312.41,     458.400,        0.000!   !END!
313 ! X =       594.77,    5312.41,     408.700,        0.000!   !END!
314 ! X =       596.77,    5312.41,     410.100,        0.000!   !END!
315 ! X =       598.77,    5312.41,     411.000,        0.000!   !END!
316 ! X =       600.77,    5312.41,     456.700,        0.000!   !END!
317 ! X =       620.77,    5312.41,     486.500,        0.000!   !END!
318 ! X =       622.77,    5312.41,     469.000,        0.000!   !END!
319 ! X =       624.77,    5312.41,     492.100,        0.000!   !END!
320 ! X =       626.77,    5312.41,     484.600,        0.000!   !END!
321 ! X =       628.77,    5312.41,     472.000,        0.000!   !END!
322 ! X =       630.77,    5312.41,     473.200,        0.000!   !END!
323 ! X =       632.77,    5312.41,     484.000,        0.000!   !END!
324 ! X =       634.77,    5312.41,     489.400,        0.000!   !END!
325 ! X =       636.77,    5312.41,     485.500,        0.000!   !END!
326 ! X =       638.77,    5312.41,     487.000,        0.000!   !END!
327 ! X =       640.77,    5312.41,     484.000,        0.000!   !END!
328 ! X =       642.77,    5312.41,     487.000,        0.000!   !END!
329 ! X =       644.77,    5312.41,     497.500,        0.000!   !END!
330 ! X =       646.77,    5312.41,     508.100,        0.000!   !END!
331 ! X =       648.77,    5312.41,     562.300,        0.000!   !END!
332 ! X =       650.77,    5312.41,     563.100,        0.000!   !END!
333 ! X =       652.77,    5312.41,     594.000,        0.000!   !END!
334 ! X =       654.77,    5312.41,     569.000,        0.000!   !END!
335 ! X =       656.77,    5312.41,     581.200,        0.000!   !END!
336 ! X =       658.77,    5312.41,     579.000,        0.000!   !END!
337 ! X =       660.77,    5312.41,     574.500,        0.000!   !END!
338 ! X =       662.77,    5312.41,     548.000,        0.000!   !END!
339 ! X =       664.77,    5312.41,     563.000,        0.000!   !END!
340 ! X =       666.77,    5312.41,     579.000,        0.000!   !END!
341 ! X =       668.77,    5312.41,     560.000,        0.000!   !END!
342 ! X =       670.77,    5312.41,     560.000,        0.000!   !END!
343 ! X =       672.77,    5312.41,     560.000,        0.000!   !END!
344 ! X =       674.77,    5312.41,     560.000,        0.000!   !END!
345 ! X =       676.77,    5312.41,     560.000,        0.000!   !END!
346 ! X =       678.77,    5312.41,     578.100,        0.000!   !END!
347 ! X =       680.77,    5312.41,     548.000,        0.000!   !END!
348 ! X =       682.77,    5312.41,     567.600,        0.000!   !END!
349 ! X =       684.77,    5312.41,     597.600,        0.000!   !END!
350 ! X =       686.77,    5312.41,     554.100,        0.000!   !END!
351 ! X =       688.77,    5312.41,     515.000,        0.000!   !END!
352 ! X =       546.77,    5314.41,     442.000,        0.000!   !END!
353 ! X =       548.77,    5314.41,     457.800,        0.000!   !END!
354 ! X =       550.77,    5314.41,     427.000,        0.000!   !END!
355 ! X =       552.77,    5314.41,     444.800,        0.000!   !END!
356 ! X =       554.77,    5314.41,     454.700,        0.000!   !END!
357 ! X =       556.77,    5314.41,     460.200,        0.000!   !END!
358 ! X =       558.77,    5314.41,     437.000,        0.000!   !END!
359 ! X =       560.77,    5314.41,     451.100,        0.000!   !END!
360 ! X =       562.77,    5314.41,     446.200,        0.000!   !END!
361 ! X =       564.77,    5314.41,     472.000,        0.000!   !END!
362 ! X =       566.77,    5314.41,     464.800,        0.000!   !END!
```

```
363 ! X =       568.77,    5314.41,     445.000,        0.000!   !END!
364 ! X =       570.77,    5314.41,     449.500,        0.000!   !END!
365 ! X =       572.77,    5314.41,     461.200,        0.000!   !END!
366 ! X =       594.77,    5314.41,     402.000,        0.000!   !END!
367 ! X =       596.77,    5314.41,     426.000,        0.000!   !END!
368 ! X =       598.77,    5314.41,     408.000,        0.000!   !END!
369 ! X =       600.77,    5314.41,     436.700,        0.000!   !END!
370 ! X =       602.77,    5314.41,     436.800,        0.000!   !END!
371 ! X =       604.77,    5314.41,     423.000,        0.000!   !END!
372 ! X =       620.77,    5314.41,     441.000,        0.000!   !END!
373 ! X =       622.77,    5314.41,     446.800,        0.000!   !END!
374 ! X =       624.77,    5314.41,     472.000,        0.000!   !END!
375 ! X =       626.77,    5314.41,     487.000,        0.000!   !END!
376 ! X =       628.77,    5314.41,     476.400,        0.000!   !END!
377 ! X =       630.77,    5314.41,     484.200,        0.000!   !END!
378 ! X =       632.77,    5314.41,     484.100,        0.000!   !END!
379 ! X =       634.77,    5314.41,     501.900,        0.000!   !END!
380 ! X =       636.77,    5314.41,     486.500,        0.000!   !END!
381 ! X =       638.77,    5314.41,     487.000,        0.000!   !END!
382 ! X =       640.77,    5314.41,     486.900,        0.000!   !END!
383 ! X =       642.77,    5314.41,     491.900,        0.000!   !END!
384 ! X =       644.77,    5314.41,     502.000,        0.000!   !END!
385 ! X =       646.77,    5314.41,     527.900,        0.000!   !END!
386 ! X =       648.77,    5314.41,     573.300,        0.000!   !END!
387 ! X =       650.77,    5314.41,     558.000,        0.000!   !END!
388 ! X =       652.77,    5314.41,     552.900,        0.000!   !END!
389 ! X =       654.77,    5314.41,     563.000,        0.000!   !END!
390 ! X =       656.77,    5314.41,     550.100,        0.000!   !END!
391 ! X =       658.77,    5314.41,     553.400,        0.000!   !END!
392 ! X =       660.77,    5314.41,     587.400,        0.000!   !END!
393 ! X =       662.77,    5314.41,     579.000,        0.000!   !END!
394 ! X =       664.77,    5314.41,     536.000,        0.000!   !END!
395 ! X =       666.77,    5314.41,     626.000,        0.000!   !END!
396 ! X =       668.77,    5314.41,     607.200,        0.000!   !END!
397 ! X =       670.77,    5314.41,     598.600,        0.000!   !END!
398 ! X =       672.77,    5314.41,     563.000,        0.000!   !END!
399 ! X =       674.77,    5314.41,     623.300,        0.000!   !END!
400 ! X =       676.77,    5314.41,     620.000,        0.000!   !END!
401 ! X =       678.77,    5314.41,     623.500,        0.000!   !END!
402 ! X =       680.77,    5314.41,     588.100,        0.000!   !END!
403 ! X =       682.77,    5314.41,     579.500,        0.000!   !END!
404 ! X =       684.77,    5314.41,     531.900,        0.000!   !END!
405 ! X =       686.77,    5314.41,     544.700,        0.000!   !END!
406 ! X =       688.77,    5314.41,     580.800,        0.000!   !END!
407 ! X =       546.77,    5316.41,     442.600,        0.000!   !END!
408 ! X =       548.77,    5316.41,     456.000,        0.000!   !END!
409 ! X =       550.77,    5316.41,     427.000,        0.000!   !END!
410 ! X =       552.77,    5316.41,     443.500,        0.000!   !END!
411 ! X =       554.77,    5316.41,     444.800,        0.000!   !END!
412 ! X =       556.77,    5316.41,     457.000,        0.000!   !END!
413 ! X =       558.77,    5316.41,     440.500,        0.000!   !END!
414 ! X =       560.77,    5316.41,     448.900,        0.000!   !END!
415 ! X =       562.77,    5316.41,     448.300,        0.000!   !END!
416 ! X =       564.77,    5316.41,     445.000,        0.000!   !END!
417 ! X =       566.77,    5316.41,     445.000,        0.000!   !END!
418 ! X =       568.77,    5316.41,     445.000,        0.000!   !END!
419 ! X =       570.77,    5316.41,     458.100,        0.000!   !END!
420 ! X =       572.77,    5316.41,     457.000,        0.000!   !END!
421 ! X =       574.77,    5316.41,     493.600,        0.000!   !END!
422 ! X =       576.77,    5316.41,     456.700,        0.000!   !END!
423 ! X =       592.77,    5316.41,     426.000,        0.000!   !END!
424 ! X =       594.77,    5316.41,     414.100,        0.000!   !END!
425 ! X =       596.77,    5316.41,     420.400,        0.000!   !END!
```

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426 ! X =       598.77,     5316.41,     412.100,        0.000!    !END!
427 ! X =       600.77,     5316.41,     410.700,        0.000!    !END!
428 ! X =       602.77,     5316.41,     432.800,        0.000!    !END!
429 ! X =       604.77,     5316.41,     411.000,        0.000!    !END!
430 ! X =       606.77,     5316.41,     426.100,        0.000!    !END!
431 ! X =       608.77,     5316.41,     411.000,        0.000!    !END!
432 ! X =       610.77,     5316.41,     409.800,        0.000!    !END!
433 ! X =       618.77,     5316.41,     435.000,        0.000!    !END!
434 ! X =       620.77,     5316.41,     452.800,        0.000!    !END!
435 ! X =       622.77,     5316.41,     437.300,        0.000!    !END!
436 ! X =       624.77,     5316.41,     518.800,        0.000!    !END!
437 ! X =       626.77,     5316.41,     457.000,        0.000!    !END!
438 ! X =       628.77,     5316.41,     471.100,        0.000!    !END!
439 ! X =       630.77,     5316.41,     472.000,        0.000!    !END!
440 ! X =       632.77,     5316.41,     468.500,        0.000!    !END!
441 ! X =       634.77,     5316.41,     487.000,        0.000!    !END!
442 ! X =       636.77,     5316.41,     486.500,        0.000!    !END!
443 ! X =       638.77,     5316.41,     495.300,        0.000!    !END!
444 ! X =       640.77,     5316.41,     487.000,        0.000!    !END!
445 ! X =       642.77,     5316.41,     502.700,        0.000!    !END!
446 ! X =       644.77,     5316.41,     516.300,        0.000!    !END!
447 ! X =       646.77,     5316.41,     518.300,        0.000!    !END!
448 ! X =       648.77,     5316.41,     534.700,        0.000!    !END!
449 ! X =       650.77,     5316.41,     548.000,        0.000!    !END!
450 ! X =       652.77,     5316.41,     535.400,        0.000!    !END!
451 ! X =       654.77,     5316.41,     548.000,        0.000!    !END!
452 ! X =       656.77,     5316.41,     518.000,        0.000!    !END!
453 ! X =       658.77,     5316.41,     533.000,        0.000!    !END!
454 ! X =       660.77,     5316.41,     535.800,        0.000!    !END!
455 ! X =       662.77,     5316.41,     552.500,        0.000!    !END!
456 ! X =       664.77,     5316.41,     533.000,        0.000!    !END!
457 ! X =       666.77,     5316.41,     578.000,        0.000!    !END!
458 ! X =       668.77,     5316.41,     578.700,        0.000!    !END!
459 ! X =       670.77,     5316.41,     598.400,        0.000!    !END!
460 ! X =       672.77,     5316.41,     594.000,        0.000!    !END!
461 ! X =       674.77,     5316.41,     603.600,        0.000!    !END!
462 ! X =       676.77,     5316.41,     618.300,        0.000!    !END!
463 ! X =       678.77,     5316.41,     622.900,        0.000!    !END!
464 ! X =       680.77,     5316.41,     639.000,        0.000!    !END!
465 ! X =       682.77,     5316.41,     651.700,        0.000!    !END!
466 ! X =       684.77,     5316.41,     659.600,        0.000!    !END!
467 ! X =       686.77,     5316.41,     629.300,        0.000!    !END!
468 ! X =       688.77,     5316.41,     648.800,        0.000!    !END!
469 ! X =       546.77,     5318.41,     442.000,        0.000!    !END!
470 ! X =       548.77,     5318.41,     442.000,        0.000!    !END!
471 ! X =       550.77,     5318.41,     434.200,        0.000!    !END!
472 ! X =       552.77,     5318.41,     427.000,        0.000!    !END!
473 ! X =       554.77,     5318.41,     442.000,        0.000!    !END!
474 ! X =       556.77,     5318.41,     427.000,        0.000!    !END!
475 ! X =       558.77,     5318.41,     442.000,        0.000!    !END!
476 ! X =       560.77,     5318.41,     453.100,        0.000!    !END!
477 ! X =       562.77,     5318.41,     442.000,        0.000!    !END!
478 ! X =       564.77,     5318.41,     457.000,        0.000!    !END!
479 ! X =       566.77,     5318.41,     457.000,        0.000!    !END!
480 ! X =       568.77,     5318.41,     451.000,        0.000!    !END!
481 ! X =       570.77,     5318.41,     443.400,        0.000!    !END!
482 ! X =       572.77,     5318.41,     457.000,        0.000!    !END!
483 ! X =       574.77,     5318.41,     461.500,        0.000!    !END!
484 ! X =       576.77,     5318.41,     454.100,        0.000!    !END!
485 ! X =       592.77,     5318.41,     426.000,        0.000!    !END!
486 ! X =       594.77,     5318.41,     401.600,        0.000!    !END!
487 ! X =       596.77,     5318.41,     405.200,        0.000!    !END!
488 ! X =       598.77,     5318.41,     404.700,        0.000!    !END!
```

```
489 ! X =      600.77,    5318.41,     414.900,       0.000!   !END!
490 ! X =      602.77,    5318.41,     396.000,       0.000!   !END!
491 ! X =      604.77,    5318.41,     411.000,       0.000!   !END!
492 ! X =      606.77,    5318.41,     426.500,       0.000!   !END!
493 ! X =      608.77,    5318.41,     436.500,       0.000!   !END!
494 ! X =      610.77,    5318.41,     425.000,       0.000!   !END!
495 ! X =      612.77,    5318.41,     420.200,       0.000!   !END!
496 ! X =      614.77,    5318.41,     445.300,       0.000!   !END!
497 ! X =      616.77,    5318.41,     456.300,       0.000!   !END!
498 ! X =      618.77,    5318.41,     436.700,       0.000!   !END!
499 ! X =      620.77,    5318.41,     444.700,       0.000!   !END!
500 ! X =      622.77,    5318.41,     470.600,       0.000!   !END!
```

----

[a] Data for each receptor are treated as a separate input subgroup and therefore must end with an input group terminator.

[b] Receptor height above ground is optional. If no value is entered, the receptor is placed on the ground.

ATTACHMENT V

CALPOST Input File (One of Six Files)

```
MPCA Taconite BART Study  - Pre-BART Emissions
Boundary Waters C. A. Wilderness (1-500)
CALMET data - 12/1/84 through 11/30/85
---------------- Run title (3 lines) ------------------------------------------

                    CALPOST MODEL CONTROL FILE
                    --------------------------

-------------------------------------------------------------------------------

INPUT GROUP: 0 -- Input and Output File Names
--------------

Input Files
-----------

File                         Default File Name
----                         -----------------
Conc/Dep Flux File           MODEL.DAT            ! MODDAT
=L:\CALPUFF\BART\OUTPUT\P85PREA.CON   !
Relative Humidity File       VISB.DAT             ! VISDAT
=L:\CALPUFF\BART\OUTPUT\P85PREA.VIS   !
Background Data File         BACK.DAT             *BACKDAT =   *
Transmissometer/             VSRN.DAT             *VSRDAT =   *
Nephelometer Data File

Output Files
------------

File                         Default File Name
----                         -----------------
List File                    CALPOST.LST          ! PSTLST
=L:\CALPOST\BART\OUTPUT\VISPREA.LST   !

Pathname for Timeseries Files   (blank)           * TSPATH =   *
(activate with exclamation points only if
providing NON-BLANK character string)

Pathname for Plot Files   (blank)                 ! PLPATH =L:\CALPOST\BART\OUTPUT\   !
(activate with exclamation points only if
 providing NON-BLANK character string)

User Character String (U) to augment default filenames
(activate with exclamation points only if
 providing NON-BLANK character string)

Timeseries                   TSttUUUU.DAT         * TSUNAM =   *

Top Nth Rank Plot            RttUUUUU.DAT
                      or     RttiiUUU.GRD         * TUNAM =   *

Exceedance Plot              XttUUUUU.DAT
                      or     XttUUUUU.GRD         * XUNAM =   *

Echo Plot                    jjjtthhU.DAT
(Specific Days)       or     jjjtthhU.GRD         * EUNAM =   *

Visibility Plot              V24UUUUU.DAT         ! VUNAM =PREA   !
(Daily Peak Summary)

-------------------------------------------------------------------------------
All file names will be converted to lower case if LCFILES = T
Otherwise, if LCFILES = F, file names will be converted to UPPER CASE
```

```
         T = lower case      ! LCFILES = F !
         F = UPPER CASE
NOTE: (1) file/path names can be up to 70 characters in length
NOTE: (2) Filenames for ALL PLOT and TIMESERIES FILES are constructed
          using a template that includes a pathname, user-supplied
          character(s), and fixed strings (tt,ii,jjj, and hh), where
                tt = Averaging Period (e.g. 03)
                ii = Rank (e.g. 02)
                jjj= Julian Day
                hh = Hour(ending)
          are determined internally based on selections made below.
          If a path or user-supplied character(s) are supplied, each
          must contain at least 1 non-blank character.

!END!
--------------------------------------------------------------------------------

INPUT GROUP: 1 -- General run control parameters
--------------

     Option to run all periods found
     in the met. file(s)  (METRUN)       Default: 0   ! METRUN =   1  !

         METRUN = 0 - Run period explicitly defined below
         METRUN = 1 - Run all periods in CALPUFF data file(s)

     Starting date:    Year  (ISYR) --    No default   ! ISYR  =  1984   !
     (used only if     Month (ISMO) --    No default   ! ISMO  =  0   !
      METRUN = 0)      Day   (ISDY) --    No default   ! ISDY  =  0   !
                       Hour  (ISHR) --    No default   ! ISHR  =  0   !

     Number of hours to process (NHRS) -- No default   ! NHRS  =  0  !

     Process every hour of data?(NREP) -- Default: 1   ! NREP  =  1  !
      (1 = every hour processed,
       2 = every 2nd hour processed,
       5 = every 5th hour processed, etc.)

Species & Concentration/Deposition Information
----------------------------------------------

      Species to process (ASPEC)       -- No default   ! ASPEC = VISIB  !
      (ASPEC = VISIB for visibility processing)

      Layer/deposition code (ILAYER)   -- Default: 1   ! ILAYER =  1  !
        '1'  for CALPUFF concentrations,
        '-1' for dry deposition fluxes,
        '-2' for wet deposition fluxes,
        '-3' for wet+dry deposition fluxes.

      Scaling factors of the form:     -- Defaults:    ! A =  0.0    !
            X(new) = X(old) * A + B         A = 0.0    ! B =  0.0    !
        (NOT applied if A = B = 0.0)        B = 0.0

      Add Hourly Background Concentrations/Fluxes?
                              (LBACK)  -- Default: F   ! LBACK =  F !

Receptor information
--------------------

  Gridded receptors processed?    (LG) -- Default: F   ! LG  = F  !
  Discrete receptors processed?   (LD) -- Default: F   ! LD  = T  !
  CTSG Complex terrain receptors processed?
```

```
                                    (LCT) -- Default: F   ! LCT = F  !

--Report results by DISCRETE receptor RING?
  (only used when LD = T)     (LDRING) -- Default: F   ! LDRING = F  !

--Select range of DISCRETE receptors (only used when LD = T):

  Select ALL DISCRETE receptors by setting NDRECP flag to -1;
                               OR
  Select SPECIFIC DISCRETE receptors by entering a flag (0,1) for each
     0 = discrete receptor not processed
     1 = discrete receptor processed
  using repeated value notation to select blocks of receptors:
     23*1, 15*0, 12*1
  Flag for all receptors after the last one assigned is set to 0
  (NDRECP) -- Default: -1
                                                ! NDRECP =  -1  !


--Select range of GRIDDED receptors (only used when LG = T):

       X index of LL corner (IBGRID) -- Default: -1     ! IBGRID = -1  !
           (-1 OR 1 <= IBGRID <= NX)

       Y index of LL corner (JBGRID) -- Default: -1     ! JBGRID = -1  !
           (-1 OR 1 <= JBGRID <= NY)

       X index of UR corner (IEGRID) -- Default: -1     ! IEGRID = -1  !
           (-1 OR 1 <= IEGRID <= NX)

       Y index of UR corner (JEGRID) -- Default: -1     ! JEGRID = -1  !
           (-1 OR 1 <= JEGRID <= NY)

  Note: Entire grid is processed if IBGRID=JBGRID=IEGRID=JEGRID=-1


--Specific gridded receptors can also be excluded from CALPOST
  processing by filling a processing grid array with 0s and 1s.  If the
  processing flag for receptor index (i,j) is 1 (ON), that receptor
  will be processed if it lies within the range delineated by IBGRID,
  JBGRID,IEGRID,JEGRID and if LG=T. If it is 0 (OFF), it will not be
  processed in the run.  By default, all array values are set to 1 (ON).

  Number of gridded receptor rows provided in Subgroup (1a) to
  identify specific gridded receptors to process
                           (NGONOFF) -- Default: 0      ! NGONOFF =  0  !

!END!


--------------
Subgroup (1a) -- Specific gridded receptors included/excluded
--------------

    Specific gridded receptors are excluded from CALPOST processing
    by filling a processing grid array with 0s and 1s.  A total of
    NGONOFF lines are read here.  Each line corresponds to one 'row'
    in the sampling grid, starting with the NORTHERNMOST row that
    contains receptors that you wish to exclude, and finishing with
    row 1 to the SOUTH (no intervening rows may be skipped).  Within
    a row, each receptor position is assigned either a 0 or 1,
    starting with the westernmost receptor.
       0 = gridded receptor not processed
```

```
      1 = gridded receptor processed

   Repeated value notation may be used to select blocks of receptors:
      23*1, 15*0, 12*1

   Because all values are initially set to 1, any receptors north of
   the first row entered, or east of the last value provided in a row,
   remain ON.

   (NGXRECP) -- Default: 1


-------------------------------------------------------------------------------

INPUT GROUP: 2 -- Visibility Parameters (ASPEC = VISIB)
--------------

   Maximum relative humidity (%) used in particle growth curve
                              (RHMAX) -- Default: 98   ! RHMAX  = 95.0 !

   Modeled species to be included in computing the light extinction
    Include SULFATE?          (LVSO4) -- Default: T   ! LVSO4  = T  !
    Include NITRATE?          (LVNO3) -- Default: T   ! LVNO3  = T  !
    Include ORGANIC CARBON?   (LVOC)  -- Default: T   ! LVOC   = F  !
    Include COARSE PARTICLES? (LVPMC) -- Default: T   ! LVPMC  = T  !
    Include FINE PARTICLES?   (LVPMF) -- Default: T   ! LVPMF  = F  !
    Include ELEMENTAL CARBON? (LVEC)  -- Default: T   ! LVEC   = F  !

   And, when ranking for TOP-N, TOP-50, and Exceedance tables,
    Include BACKGROUND?       (LVBK)  -- Default: T   ! LVBK   = F  !

   Species name used for particulates in MODEL.DAT file
                  COARSE    (SPECPMC) -- Default: PMC ! SPECPMC = PMC !
                  FINE      (SPECPMF) -- Default: PMF ! SPECPMF = PMF !

Extinction Efficiency (1/Mm per ug/m**3)
----------------------------------------
   MODELED particulate species:
              PM  COARSE      (EEPMC) -- Default: 0.6 ! EEPMC  = 0.6 !
              PM  FINE        (EEPMF) -- Default: 1.0 ! EEPMF  = 1.0 !
   BACKGROUND particulate species:
              PM  COARSE    (EEPMCBK) -- Default: 0.6 ! EEPMCBK = 0.6 !
   Other species:
             AMMONIUM SULFATE (EESO4) -- Default: 3.0 ! EESO4  = 3.0 !
             AMMONIUM NITRATE (EENO3) -- Default: 3.0 ! EENO3  = 3.0 !
             ORGANIC CARBON   (EEOC)  -- Default: 4.0 ! EEOC   = 4.0 !
             SOIL             (EESOIL)-- Default: 1.0 ! EESOIL = 1.0 !
             ELEMENTAL CARBON (EEEC)  -- Default: 10. ! EEEC   = 10.0 !

Background Extinction Computation
---------------------------------

   Method used for background light extinction
                             (MVISBK) -- Default: 6   ! MVISBK =  2  !

        1 =  Supply single light extinction and hygroscopic fraction
             - IWAQM (1993) RH adjustment applied to hygroscopic background
               and modeled sulfate and nitrate
        2 =  Compute extinction from speciated PM measurements (A)
             - Hourly RH adjustment applied to observed and modeled sulfate
               and nitrate
             - RH factor is capped at RHMAX
        3 =  Compute extinction from speciated PM measurements (B)
```

```
          - Hourly RH adjustment applied to observed and modeled sulfate
            and nitrate
          - Receptor-hour excluded if RH>RHMAX
          - Receptor-day excluded if fewer than 6 valid receptor-hours
     4 =  Read hourly transmissometer background extinction measurements
          - Hourly RH adjustment applied to modeled sulfate and nitrate
          - Hour excluded if measurement invalid (missing, interference,
            or large RH)
          - Receptor-hour excluded if RH>RHMAX
          - Receptor-day excluded if fewer than 6 valid receptor-hours
     5 =  Read hourly nephelometer background extinction measurements
          - Rayleigh extinction value (BEXTRAY) added to measurement
          - Hourly RH adjustment applied to modeled sulfate and nitrate
          - Hour excluded if measurement invalid (missing, interference,
            or large RH)
          - Receptor-hour excluded if RH>RHMAX
          - Receptor-day excluded if fewer than 6 valid receptor-hours
     6 =  Compute extinction from speciated PM measurements
          - FLAG RH adjustment factor applied to observed and
            modeled sulfate and nitrate

Additional inputs used for MVISBK = 1:
--------------------------------------
 Background light extinction (1/Mm)
                          (BEXTBK) -- No default   ! BEXTBK = 52.2 !
 Percentage of particles affected by relative humidity
                          (RHFRAC) -- No default   ! RHFRAC = 51.7 !

Additional inputs used for MVISBK = 6:
--------------------------------------
 Extinction coefficients for hygroscopic species (modeled and
 background) are computed using a monthly RH adjustment factor
 in place of an hourly RH factor (VISB.DAT file is NOT needed).
 Enter the 12 monthly factors here (RHFAC).  Month 1 is January.

 (RHFAC)  -- No default     ! RHFAC = 3.7, 3.7, 2.6, 2.6,
                                      2.6, 3.4, 3.4, 3.4,
                                      4.1, 4.1, 4.1, 3.7 !

Additional inputs used for MVISBK = 2,3,6:
----------------------------------------
 Background extinction coefficients are computed from monthly
 CONCENTRATIONS of ammonium sulfate (BKSO4), ammonium nitrate (BKNO3),
 coarse particulates (BKPMC), organic carbon (BKOC), soil (BKSOIL), and
 elemental carbon (BKEC).  Month 1 is January.
 (ug/m**3)

 (BKSO4)  -- No default     ! BKSO4 = 0.3, 0.3, 0.3, 0.3,
                                      0.3, 0.3, 0.3, 0.3,
                                      0.3, 0.3, 0.3, 0.3 !
 (BKNO3)  -- No default     ! BKNO3 = 0.0, 0.0, 0.0, 0.0,
                                      0.0, 0.0, 0.0, 0.0,
                                      0.0, 0.0, 0.0, 0.0 !
 (BKPMC)  -- No default     ! BKPMC = 0.0, 0.0, 0.0, 0.0,
                                      0.0, 0.0, 0.0, 0.0,
                                      0.0, 0.0, 0.0, 0.0 !
 (BKOC)   -- No default     ! BKOC  = 0.0, 0.0, 0.0, 0.0,
                                      0.0, 0.0, 0.0, 0.0,
                                      0.0, 0.0, 0.0, 0.0 !
 (BKSOIL) -- No default     ! BKSOIL= 8.5, 8.5, 8.5, 8.5,
                                      8.5, 8.5, 8.5, 8.5,
                                      8.5, 8.5, 8.5, 8.5 !
 (BKEC)   -- No default     ! BKEC  = 0.0, 0.0, 0.0, 0.0,
```

```
                                    0.0, 0.0, 0.0, 0.0,
                                    0.0, 0.0, 0.0, 0.0 !

    Additional inputs used for MVISBK = 2,3,5,6:
    ------------------------------------------
     Extinction due to Rayleigh scattering is added (1/Mm)
                         (BEXTRAY) -- Default: 10.0 ! BEXTRAY = 10.0 !

!END!
-------------------------------------------------------------------------------

INPUT GROUP: 3 -- Output options
--------------

Output Units
------------
    Units for All Output       (IPRTU) -- Default: 1   ! IPRTU =  1   !
                  for               for
            Concentration    Deposition
       1 =        g/m**3          g/m**2/s
       2 =       mg/m**3         mg/m**2/s
       3 =       ug/m**3         ug/m**2/s
       4 =       ng/m**3         ng/m**2/s
       5 =      Odour Units

    Visibility: extinction expressed in 1/Mega-meters (IPRTU is ignored)


Averaging time(s) reported
--------------------------

    1-hr averages           (L1HR) -- Default: T   !   L1HR = F  !

    3-hr averages           (L3HR) -- Default: T   !   L3HR = F  !

    24-hr averages         (L24HR) -- Default: T   !  L24HR = T  !

    Run-length averages    (LRUNL) -- Default: T   !  LRUNL = F  !

    User-specified averaging time in hours - results for
    an averaging time of NAVG hours are reported for
    NAVG greater than 0:
                             (NAVG) -- Default: 0   !   NAVG =  0  !


Types of tabulations reported
------------------------------

   1) Visibility: daily visibility tabulations are always reported
                  for the selected receptors when ASPEC = VISIB.
                  In addition, any of the other tabulations listed
                  below may be chosen to characterize the light
                  extinction coefficients.
                  [List file or Plot/Analysis File]


   2) Top 50 table for each averaging time selected
      [List file only]
                             (LT50) -- Default: T   !   LT50 = F  !

   3) Top 'N' table for each averaging time selected
      [List file or Plot file]
                            (LTOPN) -- Default: F   !  LTOPN = T  !
```

```
       -- Number of 'Top-N' values at each receptor
          selected (NTOP must be <= 4)
                           (NTOP) -- Default: 4   ! NTOP =  4   !

       -- Specific ranks of 'Top-N' values reported
          (NTOP values must be entered)
                  (ITOP(4) array) -- Default:     ! ITOP =  1 , 2 , 3 , 4   !
                                     1,2,3,4


   4) Threshold exceedance counts for each receptor and each averaging
      time selected
      [List file or Plot file]
                          (LEXCD) -- Default: F   !  LEXCD = F  !

       -- Identify the threshold for each averaging time by assigning a
          non-negative value (output units).

                                  -- Default: -1.0
          Threshold for  1-hr averages   (THRESH1) !  THRESH1 = -1.0  !
          Threshold for  3-hr averages   (THRESH3) !  THRESH3 = -1.0  !
          Threshold for 24-hr averages  (THRESH24) ! THRESH24 = 3.0E-01 !
          Threshold for NAVG-hr averages (THRESHN) !  THRESHN = -1.0  !


       -- Counts for the shortest averaging period selected can be
          tallied daily, and receptors that experience more than NCOUNT
          counts over any NDAY period will be reported.  This type of
          exceedance violation output is triggered only if NDAY > 0.

          Accumulation period(Days)
                           (NDAY) -- Default: 0   !    NDAY =  0  !
          Number of exceedances allowed
                         (NCOUNT) -- Default: 1   !  NCOUNT =  1  !


   5) Selected day table(s)

      Echo Option -- Many records are written each averaging period
      selected and output is grouped by day
      [List file or Plot file]
                          (LECHO) -- Default: F   !  LECHO = F  !

      Timeseries Option -- Averages at all selected receptors for
      each selected averaging period are written to timeseries files.
      Each file contains one averaging period, and all receptors are
      written to a single record each averaging time.
      [TSttUUUU.DAT files]
                          (LTIME) -- Default: F   !  LTIME = F  !

       -- Days selected for output
                     (IECHO(366)) -- Default: 366*0
          ! IECHO  = 366*0  !
          (366 values must be entered)

Plot output options
-------------------

     Plot files can be created for the Top-N, Exceedance, and Echo
     tables selected above.  Two formats for these files are available,
     DATA and GRID.  In the DATA format, results at all receptors are
     listed along with the receptor location [x,y,val1,val2,...].
```

```
     In the GRID format, results at only gridded receptors are written,
     using a compact representation.  The gridded values are written in
     rows (x varies), starting with the most southern row of the grid.
     The GRID format is given the .GRD extension, and includes headers
     compatible with the SURFER(R) plotting software.

     A plotting and analysis file can also be created for the daily
     peak visibility summary output, in DATA format only.

     Generate Plot file output in addition to writing tables
     to List file?
                                 (LPLT) -- Default: F   ! LPLT  = T !

     Use GRID format rather than DATA format,
     when available?
                                 (LGRD) -- Default: F   ! LGRD  = F !


Additional Debug Output
-----------------------

   Output selected information to List file
    for debugging?
                               (LDEBUG) -- Default: F  ! LDEBUG  = T !

!END!
```